A Core/Noncore Structure for Electricity in California

Staff Report
Division of Strategic Planning
California Public Utilities Commission

March 15th, 2004

STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

March 15, 2004

Honorable Debra Bowen
Chair, Senate Committee on Energy,
Communications and Utilities
State Capitol
Sacramento, CA 95814

Honorable Sarah Reyes
Chair, Assembly Committee on
Utilities and Commerce
State Capitol
Sacramento, CA 95814

Dear Senator Bowen and Assemblywoman Reyes:

President Peevey committed to provide you with a study by March 15 that applied the Core/Noncore market structure to the retail electric marketplace. We are pleased to provide you with the staff report "A Core/Noncore Structure for Electricity in California." This report describes the need to establish certainty in the retail electric market structure, and, if California adopts a Core/Noncore structure, identifies the features such a structure should include. The features are designed to provide retail electric provider choice and ensure sufficient new infrastructure development while guaranteeing consumer protections. The report is not an endorsement of the Core/Noncore model; instead, if Core/Noncore is pursued, it is meant to chart the best course forward.

This is a staff report. It is not intended to represent the views of the Commissioners; it was prepared to inform those views. We look forward to discussing it with you.

Sincerely,

William R. Ahern
Executive Director

Barbara Hale
Director, Division of Strategic Planning

cc: Honorable John Burton, President Pro Tempore of the Senate
Honorable Fabian Nuñez, Speaker of the Assembly
Honorable James L. Brulte, Senate Republican Leader

Honorable Kevin McCarthy, Assembly Republican Leader
Honorable Bill Morrow, Vice-Chair, Senate Energy, Utilities and Communications Committee
Honorable Keith Richman, M.D., Vice-Chair, Assembly Utilities and Commerce Committee
Members, Senate Energy, Utilities and Communications Committee
Members, Assembly Utilities and Commerce Committee
CPUC Commissioners

The concept of a Core/Noncore market structure allows large customers competitive choice, while small customers retain the security of bundled utility service. This report is not an endorsement of the Core/Noncore model; instead, if Core/Noncore is pursued, it is meant to chart the best course forward

This report was prepared by James Hendry, Sepideh Khosrowjah and Dan Adler, with guidance and support from Barbara Hale. To obtain a copy of this report, refer to the Commission's web page http://www.cpuc.ca.gov/ or contact Evelyn Gaviola of the Division of Strategic Planning, 415-703-1245.

Note regarding Data Sources: In preparing this report, Staff has relied upon publicly available information, particularly forecasts prepared by DWR as part of its revenue requirement process. In its proceedings, the Commission uses specific data provided by the utilities, much of which is provided under the confidentiality provisions of Public Utilities Code 583. Therefore forecasts and estimates are presented for illustrative purposes as showing general trends. Specific updates of this information should be performed as part of any discussion over the future structure of the electric market. Use of information contained in this report should not be taken as support of this information in any proceeding before the Commission.

Glossary

AB 1890: State legislation enacted in 1996 opening the electric retail market to competition.

Community Choice Aggregation (CCA): A state program permitting a local government board, or combination of governments to create an entity to procure electricity on behalf of local citizens, businesses, and itself.

Cost Responsibility Surcharge (CRS): The mechanism by which the Commission has allocated costs associated with past utility and Department of Water Resources commitments to Direct Access customers.

Direct Access (DA): The ability of retail customers to choose their own electricity provider.

Energy Service Provider (ESP): Load serving entities other than IOUs.

Investor Owner Utility (IOU): A regulated utility entity whose assets are owned by investors.

Kilowatt (kW): A Common unit of measure of electric power.

Load-serving entities (LSEs): Entities responsible for serving retail electric load.

Megawatt (MW): 1000 KW, roughly sufficient to meet the electric demand of 1,000 households.

Peak Load: The maximum amount of demand a customer places on the electrical system at any given point in time.

Provider Of Last Resort (POLR): The designation applied to an entity responsible for providing service in the event of failure by an ESP.

Qualifying Facilities (QF): Generation resources given special regulatory status under the Public Utilities Regulatory Policy Act (PURPA) of 1978.

Renewable Portfolio Standard (RPS): A state program requiring incremental increases in renewable energy generation by at least 1% per year until renewables comprise 20% in total, with a deadline of 2017.

Residual Net Short (RNS): The amount of each utility's energy need that is not under contract.

Resource Adequacy: The Commission established in D.04-01-050 that all LSEs in the IOU's franchise territories must demonstrate the ability to meet 115-117% of the peak load for which they are responsible. This requirement is to be met by January 2008, with specific milestones and assessment methods to be developed by the Commission this year.

Utility Retained Generation (URG): Generation that is part of the utility's portfolio, either owned or under contract.

Executive Summary

Two of California's highest priorities for its electricity system are potentially in conflict: the need to establish relative certainty in the retail electricity market, and recreating some measure of retail choice earlier than 2013.[1] The assignment addressed by this report is to design a system that both provides Californians choice and ensures sufficient new infrastructure development, while guaranteeing broad and robust consumer protections.

The concept of a Core/Noncore market - currently employed in California's natural gas industry - allows large customers competitive choice, while small customers retain the security of bundled utility service. It is proposed as an electric market reform in pending state legislation, and amounts to limited re-instatement of Direct Access. The Core/Noncore concept is analyzed and applied to the electricity industry in this report.

The report is premised on the notion that some change to the *status quo* will be made in the coming years. It assumes this will allow customer choice to be reinstated while Department of Water Resources contracts are still in effect and California is still working off the debt associated with the electricity crisis. The report recognizes the need for certainty in the marketplace so that timely infrastructure investments can be made. This certainty requires either some affirmative reform, one example of which is a Core/Noncore structure, or certainty that the suspension of Direct Access will continue until 2013.

Based on these assumptions the report recommends a Core/Noncore market design with specific conditions that must be met as implementation progresses. The report is not an endorsement of the Core/Noncore model; instead, if Core/Noncore is pursued, it is meant to chart the best course forward.

[1] Under current law, Direct Access is suspended until 2013, when the last long-term Department of Water Resources (DWR) contract expires. Direct Access allows customers to choose their own provider of energy (other than the utility) while the utility retains the responsibility for transmitting and delivering this energy to the end-use customer.

The report concludes that once certain recommendations are met, a limited Core/Noncore market could start in 2009

The planning horizon for this document is the ten-year period between today and the expiration of the Direct Access suspension in 2013. During this period California will be working to address the after-affects of the energy crisis, and to establish a stable wholesale market for all of the state's electricity users. The report should be considered an interim plan to provide limited retail choice during this period, minimizing the creation of new sunk costs and further risks to ratepayers, anticipating further Legislative direction as to the structure of the retail market subsequent to 2013.

The report concludes that once the recommendations are met, a limited Core/Noncore market could start in 2009. This is approximately four years ahead of the current date that the presently legislatively mandated Direct Access suspension would end. The amount of new load available for Noncore status in 2009 would largely be a function of expiring QF and short-term IOU commitments in 2009.

Beginning in 2010, with the expiration of substantial amounts of DWR contracts, Noncore opportunities increase to approximately 2,000 MW in 2010, approximately 2000 MW in 2011, and approximately 5,000 MW in 2012. Expiration of DWR contracts alone could potentially increase by 45% the size of the current Direct Access market by 2010, increasing its potential share of the total electric market to 20%. By 2012, the total size of the Direct Access market could be as large as 30% of the total market.

To successfully move in this direction a smooth and careful transition will be critical. We should learn from the last electric retail reform effort and provide for interim "off-ramps" and potential decision points to defer implementation, if needed. Retail choice with substantial Direct Access appears to function relatively well in states with excess capacity, but when tested by tight supply conditions, as in California and recently in Texas, the potential for system instability and economic shock is substantial[2].

Principles Guiding the Analysis

In considering the development of any Core/Noncore structure, California should ensure a careful, measured and fair transition to opening up the electricity market.

Additionally, any market structure should meet the following criteria:

1) *Symmetric risk:* Noncore customers leaving utility service face potential benefits and risks that depend on how the competitive market is structured. In financial terms, there are "upsides and downsides" to this choice. Fairness suggests that both the upside benefits and downside risks should be borne by the Noncore customer only, prohibiting cost-shifting and protecting the Core from any reliability concerns originating within the Noncore.

2) *Real benefits:* Any new market structure should deliver real benefits. Any cost savings should be achieved through improved efficiencies and not through the re-allocation of existing costs. As was shown with AB1890, estimated savings may not be achieved.

3) *Maintaining reliability*: Any structure should ensure that the system could be operated reliably under both short-term (i.e. meeting peak summer demand) and long-term conditions (i.e. ensuring that sufficient capacity is available and that new capacity is added when needed.)

4) *Maintaining Public Purpose Programs:* The Legislature has adopted a number of programs that are either funded through rates or implemented by the Commission and/or the utilities it regulates. These programs include energy efficiency, low-income and baseline allowances for ratepayers, and the promotion of renewable energy. These public purpose goals should be maintained under any system.

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[2] For instance, Texas Commercial Energy (TCE) was forced into bankruptcy in March 2003 as a result of high prices in the Texas short-term electricity markets. This ESP had been procuring for its load largely from these markets, with insufficient long-term commitments.

In reviewing the applicability of these principles to the current framework, the report makes the following observations on the current state of the electric market.

There is a Need for Certainty in the Regulatory Structure so that Timely Infrastructure Investments Will Be Made

Utilities, customers, and the financial community are all unclear as to the future shape of the California electric market. Certainty regarding the market structure must be established. The Legislature could establish this certainty by: 1) reintegrating the utilities and dismantling Direct Access; or 2) declaring that no change will be made to market structure until 2013; or 3) allowing some new form of retail competition.

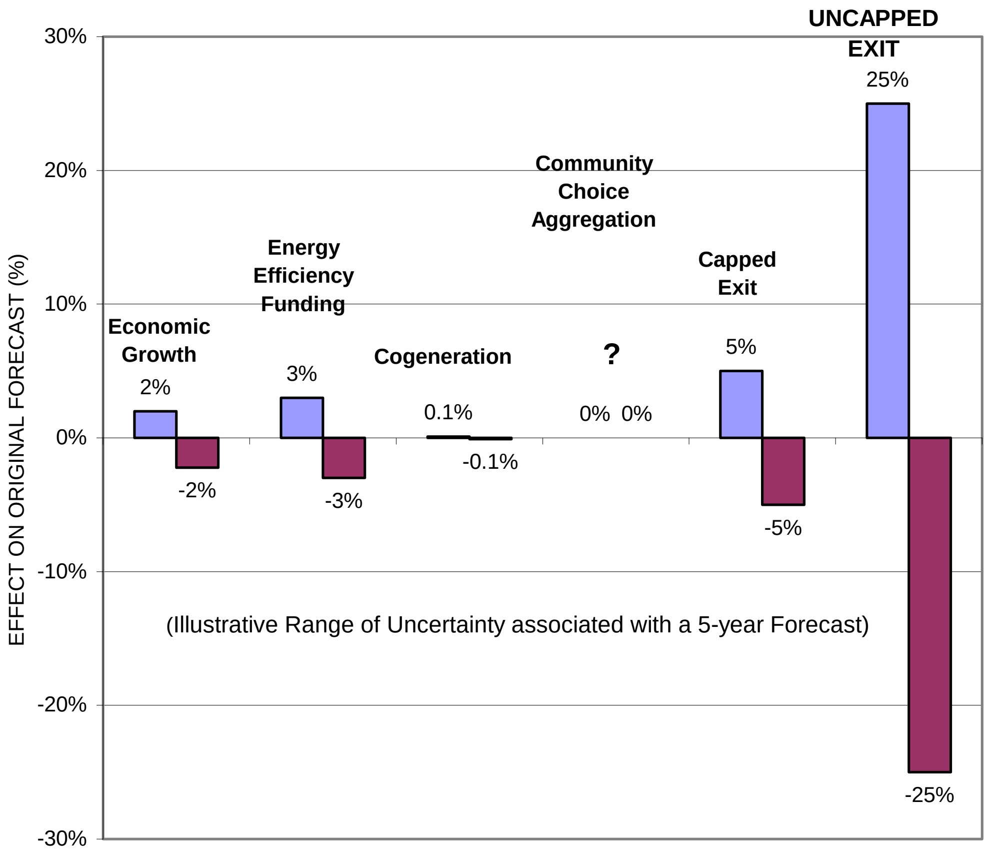
There is a need for certainty in the regulatory structure so that timely infrastructure investments will be made

The Utilities Need a Reasonable Degree of Certainty as to the Amount of Load They Must Plan For

Under any market structure, the utilities should know with a reasonable degree of certainty what level of load they are responsible for serving. Otherwise they could over-commit to new resources or find themselves short, with negative implications for bundled customers. Therefore, there needs to be clearly-defined rules as to who the utility is obligated to serve, and how long ahead of time customers seeking an alternative to utility service should give notice.

The following chart compares the uncertainties that the utilities have traditionally planned for as compared to the uncertainty introduced by a Noncore structure.

UNCERTAINTIES AFFECTING UTILITY RESOURCE PLANNING



California Needs New Infrastructure Investments in the Near to Medium Term

The California Energy Commission (CEC), California Independent System Operator (ISO) and the Commission are currently evaluating California's need for new resource additions. California may have to make new resource additions in the near future to meet anticipated load growth in the 2006-2008 time frame.

In the Short Term it Appears Only the Utilities are Able to Get Power Plants Built

Current uncertainty as to the retail electric market structure and in the financial markets is likely to favor existing utilities in financing new resource additions. The only entities capable of making long-term investment in new power plants appear to be utilities, which are able to utilize their guaranteed cost recovery through rate base.

The merchant generation sector, which had previously financed a significant amount of new construction, is currently in serious financial distress, and appears unable to build new projects unless financed through a long-term contract.

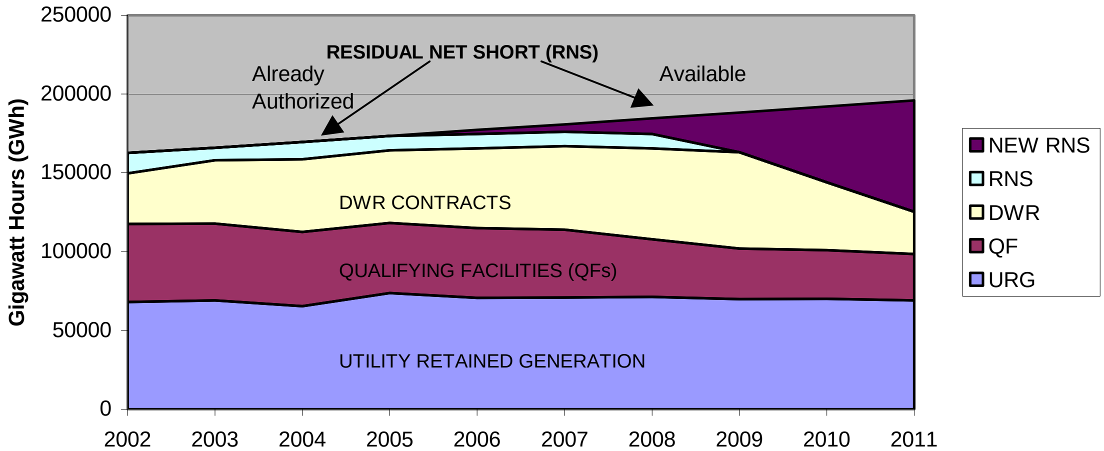
Almost all electric customers are typically unwilling (for a variety of valid economic and business reasons) to enter into contracts for longer than 1-3 years. Power plant developers (and the investment community upon which they rely), by contrast, are unwilling to invest absent longer-term contracts of 10-15 years. Any successful Noncore structure must develop a way to address this temporal gap for power plant developers to commit new capacity to a Noncore market.

The Utilities Have Already Acquired Resources to Meet Substantially All of the Needs of Their Customers Through 2009

Prior to 2009, substantially all of the total energy needs for all customers taking bundled service from the utility have already been acquired by the utilities, much of it under long-term contract. Therefore, the utilities lack the flexibility to reduce their energy purchases to reflect the departure of any of their existing load without creating additional stranded costs.

The following chart shows the amount of Residual Net Short (RNS) through 2011. RNS is the amount of energy the utility needs to buy after taking into account its own Utility Retained Generation (URG) and long-term DWR contracts. As shown the RNS is only about 5-8% of total utility load. In 2003, the utilities resumed purchasing to meet their own energy needs, replacing DWR, and have subsequently entered into additional energy contracts for various terms. This further reduces the amount of the RNS.

RESIDUAL NET SHORT AS A PORTION OF LONG-TERM UTILITY OBLIGATIONS



The utilities have already acquired resources to meet substantially all of the needs of their customers through 2009

Short-term Savings are Likely to Be Small

The Commission approved substantial rate reductions for Edison in August 2003 and for PG&E in February 2004. These reductions were due to the end of the Edison PROACT settlement and the settlement of the PG&E bankruptcy. Going forward it is less certain if there are any further opportunities for significant rate reductions.

Since essentially all existing resources are already committed under long-term obligations almost all of the components of California's current electric rates are relatively fixed for the next five years. The major components of California's high rates reflect the costs of repaying the DWR bonds, the cost of long-term above-market DWR contracts, the PG&E bankruptcy costs, and on-going above-market payments to Qualifying Facilities. Thus the potential for any significant cost savings is minimal until the long-term DWR contracts begin to expire in 2010.

There May Be Other Benefits to Allowing Choice

Allowing customers to choose a different provider, even if there are no discernible price savings, may offer benefits such as increased flexibility, new and different service options, greater control over usage, and other benefits. Additionally, the possibility of customers switching may incent the utility to better address the concerns of their customers more than they would under a structure where choice is not available. Allowing choice also provides a potential benchmark to measure the efficiency of utility-provided services. It is not possible to quantify these savings, but they are potentially of some value to customers.

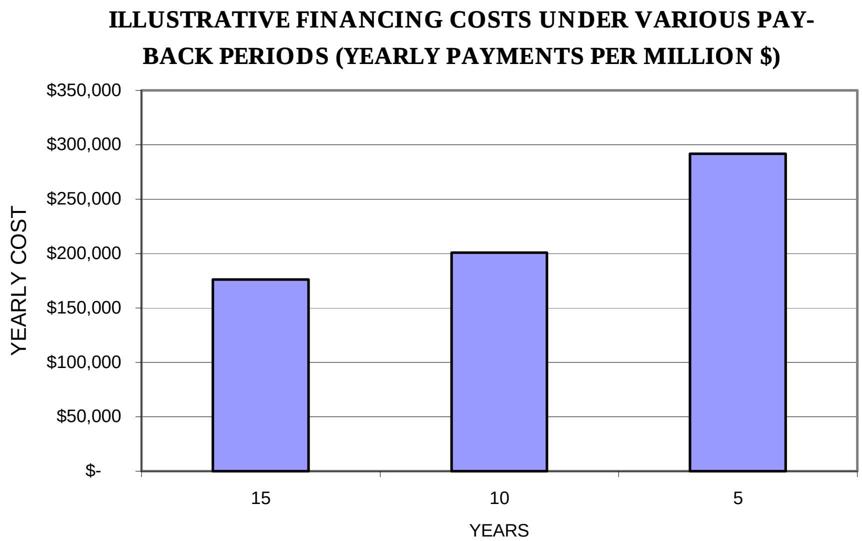
Cost shifting between customer classes is precluded by statute

Cost-shifting Between Customer Classes is Precluded by Statute

The Legislature, as well as the Commission, has previously determined that all customers are responsible for paying their "fair share" of above market resource costs. These costs should not be shifted to other customers. The Commission has addressed this issue by establishing a Cost Responsibility Surcharge (CRS) for all customers, with the exception of customers who retained Direct Access service throughout the crisis, representing about 2% of load.

The Composition of the Core Portfolio May Change

Through adoption of effective CRS charges, Core customers may be protected against cost shifting between Core and Noncore customers. However, the potential for customers to switch (even if required to give 3 to 5 years notice) is likely to bias the portfolio of utility resources available to meet demand toward shorter-term contracts and products. Thus, Core customers could face potentially higher costs and increased price volatility.



Larger Customers are the Primary Customers Who Choose an Alternative Supplier

Based on the experiences of California and most other states, the primary customers choosing an alternative supplier have been larger customers. This may support segmenting the electric industry into a competitive Noncore sector of larger customers, and a regulated Core sector comprised of residential and small commercial customers.

Implementation Issues and Recommendations

It is challenging to implement a Core/Noncore separation in California's present electricity market because the market is characterized by substantial debt, long-term contract commitments and the need for new generation infrastructure soon. These challenges are addressed by:

- Designing strict cost responsibility provisions for departing customers
- Coordinating departure from utility service with expiring DWR contract commitments, and
- Implementing strict resource adequacy requirements for all load-serving entities.

Unlike most of the markets where retail choice is considered relatively successful, California does not enjoy a substantial overcapacity of generation to support the short-term transactions characteristic of competitive electric procurement. Careful consideration must therefore be paid to the implementation issues addressed below if California is to continue its recovery from the events of 2000/2001.

Because of the high cost to Californians and our economy of getting it wrong, all of the milestone activities described below should be completed *before* customers are allowed to choose service from non-utility providers

The table below presents key implementation timeline issues discussed in the text that follows. Because of the high cost to Californians and our economy of getting it wrong, all of the milestone activities described below should be completed *before* customers are allowed to choose service from non-utility providers. Following this recommendation, all of the milestone activities must be completed in 2006, before the second round of investor-owned utility long-term plans are approved[3] (with the important exception of the resource adequacy requirement, to be completed by January 2008).

[3] This schedule is dependent upon legislative enactment sufficient to allow 12 months of Commission implementation.

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Resource Adequacy Implemented		Begins			Completed					
DWR Obligations Expire (approx. MW)	1500	1500	300				2000	2000	5000	1000
IOU Long-Term Plan Filings			X		X		X		X	
Present Capped CRS Expires								X		
First Eligible Customers Notify IOU			X							
New Noncore CRS Calculated for 2009			X							
First Noncore Exit						X				

Ensure Resource Adequacy Requirements Are Met

The Commission established in its recent Procurement decision, D.04-01-050, that all load-serving entities (LSEs) in the franchise territories must demonstrate the ability to meet 115-117% of the peak load for which they are responsible. This requirement is to be met by January 2008. The Commission is currently holding workshops to implement this requirement. This requirement should be a precondition to the creation of a Noncore market.

Link Noncore Exit to Expiring Utility Contractual Commitments

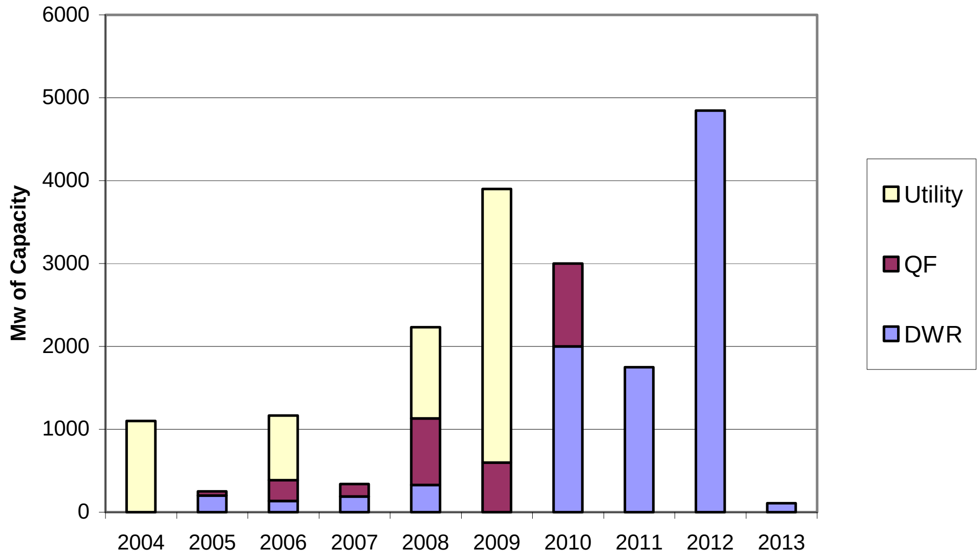
Long-term utility-contracted generation commitments begin to expire in 2009, which is the first full year after the Commission's resource adequacy requirements will be in effect. Allowing Noncore exit prior to this point would create new stranded costs, avoidance of which is a high priority in this analysis. It is therefore recommended that the first Noncore exit opportunity be allowed in 2009, with potential Noncore customers declaring their interest in leaving utility service in mid-2006. This timing will also allow the utility to make reasonable investment decisions for its Core customers in the 2006 long-term planning cycle previously established by the Commission.

It is recommended that the first Noncore exit opportunity be allowed in 2009, with potential Noncore customers declaring their interest in leaving utility service in mid-2006

Between now and March 2006 the Commission should:

- Determine the precise amount of load available to Noncore customers in the years 2009-2013
- Calculate the appropriate Cost Responsibility Surcharge (CRS) for customers leaving in 2009
- Complete its bottoms-up ratemaking process to allow potential Noncore customers to see the true costs of utility service and therefore make economically efficient decisions
- Establish key Provider of Last Resort provisions (described below), and
- Develop a method of tracking the deferred obligations accrued by Noncore customers as a result of the capped CRS. Presently bundled customers choosing Noncore service in 2009 will be owed their accrued portion of the deferred obligations resulting from the capped CRS.

UPCOMING MAJOR ENERGY RESOURCE CONTRACT EXPIRATIONS



MAJOR UTILITY INVESTMENT DECISIONS 2004-2010

Mojave Coal Plant (A.02-05-004): Application by Southern California Edison regarding spending $1.1. Billion on pollution control retrofits and refurbishments at the 1,580 Mw Mojave coal plant. Edison owns 56% of the plant.

San Onofre Nuclear Generating Station (SONGS) (A.04-02-026): $650 million to replace steam turbines at this 2200 Mw nuclear power plant. Replacement would occur in 2009. Edison's share of upgrade would be $500 million, SDG&E's share as a partial owner of SONGS would be $110 million. (Source Edison SEC 8-K filing)

Diablo Canyon Nuclear Power Plant (A.04-01-009): Application by Pacific Gas & Electric to begin preliminary engineering/design work associated with replacing the steam turbines at this 2200 Mw nuclear power plant. Replacement would occur in 2008 (Unit 2) and 2009 (Unit 1) at an estimated cost of $706 million.

SDG&E Request for Proposal (R.00-10-024): Request by SDG&E to acquire approximately 1,100 Mw of new capacity including the Palomar (550 Mw) and Otay Mesa power plants (550 Mw).

Address the Effect of a Capped CRS on Bundled Customers

The present capped Cost Responsibility Surcharge creates deferred financial obligations to which Core customers will ultimately be entitled, to be repaid with interest. Each new customer taking service with a capped CRS increases the financial burden on bundled customers. Allowing more customers to leave at a capped CRS therefore creates further deferred financial obligations, which must be spread over a shrinking number of bundled customers. This is an untenable situation. We therefore recommend that Noncore customers pay an uncapped CRS reflecting their full cost responsibility. Financial commitments made on the part of bundled customers since the suspension of Direct Access – the point from which the original CRS was calculated – should also be added to the CRS of Noncore customers.

The initial threshold for Noncore participation should be set at 500 kW minimum peak load

Set the Initial Threshold for Participation at 500 kW Minimum Peak Load

Linking the opportunity for Noncore exit to expiring utility contracts limits the creation of new stranded costs and the attendant financial risks to bundled ratepayers. The opportunity created for exit should be first allocated to customers with a minimum of 500 kW peak load. This category includes the large industrial customers most likely to leave California because of high electricity costs, threatening the state's jobs and tax bases. We recommend this threshold be employed for the first "open season," in the 2006 IOU planning cycle. If the amount allocated at that time for 2009 exit is not fully subscribed by the 500 kW customer class, consideration should be given to lowering the size threshold.

Do Not Permit Aggregation Prior to the Expiration of All DWR Contracts[4]

Aggregation would allow a number of smaller customers to combine their electricity demand to reach the minimum size threshold for Noncore eligibility. In order to direct the initial potential benefits of the Noncore option to large industrial customers, those most likely to leave California, we recommend allowing no customer aggregation through 2013. However, should the initial Noncore allocation not be fully subscribed, consideration should be given to allowing aggregation, up to the established MW limits for each year, in post-2006 utility planning cycles.

Coordinate Exit and Entry with Utility Planning Cycles

The utilities are presently on two-year planning cycles before the Commission. In order to avoid the creation of new stranded costs and the financial risks to bundled ratepayers these costs pose, potential Noncore customers should be required to declare their interest in leaving utility service on a schedule that allows the IOUs to plan for the appropriate commitment to new resources. For instance, interested customers should be required to declare their intent prior to the adoption of each utility's long-term plan in 2006. Similarly, Noncore customers who choose to return to utility service on an orderly basis should be required to give adequate notice to coordinate with IOU planning. The method of determining which customers are allowed to exit – such as an auction, random selection, or on a first-come basis – will require further study.

Establish the IOU as Provider of Last Resort, with Two Categories of Service

A source of substantial risk to California and to bundled ratepayers in the Core/Noncore structure lies in the potential for unexpected customer swings back from the Noncore to utility service. The option of physical interruptibility of all Noncore customers without sufficient generation resources is not endorsed here, as too damaging to the California economy. At the same time this backstop service provision should not be costless for Noncore customers, as it is now with

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[4] This recommendation is not intended to restrict Community Choice Aggregation, which is permitted by state law.

the IOUs obligated to serve all customers. We therefore recommend a two-tiered approach to the provision of this backstop service.

The first option, "Capacity-Assured Noncore," has the IOU providing for all the capacity needs for the Noncore customer, with costs recovered as a nonbypassable charge on the customer's bill. Core customers would not be liable in any way for the provision of this capacity service. Capacity-Assured Noncore customers would choose competing, non-utility service for their electricity needs. They would be allowed to return to full utility service with relatively broad latitude, subject to specific terms.

The second option, "Capacity-Independent Noncore," requires a complete break from IOU service by the Noncore customer, provided that the Energy Service Provider in question demonstrates resource adequacy as described above. Noncore customers in this category receive both capacity and energy service from the ESP, and can be guaranteed return to IOU service only on a strict timeline that coordinates with the IOU planning cycle. Noncore customers returning on an uncoordinated basis may be subject to high prices for short-term purchases made by the IOU on their behalf, and may be subject to interruption if generation cannot be procured for them on a real-time basis.

Complete Bottoms-Up Ratemaking to Enable Efficient Decisions for Noncore Customers

Potential Noncore customers should be able to assess the benefits of Noncore service by comparing the Noncore rate to the actual cost of electricity from IOU service. This means two things: IOU rates for potential Noncore customers should not be artificially inflated to stimulate competition, and these rates should not allocate to other customer classes costs attributable to potential Noncore customers. It is recommended that the Commission accomplish this efficient and fair allocation of costs via its "bottoms-up" approach to ratemaking.

Provide Certain Choice Options for Core Customers

This report recognizes the non-price benefits that may be available in a retail choice regime, such as billing services that enable better management of customers' energy budgets. We recommend that the state consider adopting market rules for competitive billing service provision, in a manner that would capture these benefits without requiring the re-opening of retail competition. In a Core/Noncore structure Core customers should continue to have options regarding Time of Use and Real-Time Pricing opportunities. Green choice should also be made available to Core customers, as a companion program to the Renewable Portfolio Standard, and should be considered immediately while Core/Noncore issues are debated.

Maintain Public Purpose Programs with Participation by All Customers

All customers should continue to support these programs via nonbypassable Public Goods Charges. Energy efficiency funds should be utilized for Core and Noncore customers alike, and efficiency programs should be designed to capture the savings available in both customer classes. As required by current law, the Renewable Portfolio Standard should apply to all LSEs on a percent-of-load basis. The report makes specific recommendations as to how these Public Purpose Programs should be pursued in a Core/Noncore structure.

CHAPTER 1
BACKGROUND

The term "Core/Noncore" comes from the natural gas industry, where federal and state regulatory efforts restructured the industry through the mid-1980s and into the early 1990s

A. The Purpose of This Report

This study examines the feasibility of creating a "Core/Noncore market structure" (CNC) for that portion of California's electric industry regulated by the California Public Utilities Commission (CPUC). This includes California's three largest investor-owned utilities (IOUs): Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE or Edison), as well as several smaller IOUs.[5] Collectively, these utilities serve about 75% of California's electric demand, with the remainder served by municipal utilities, irrigation districts and cooperatives.[6]

The term "Core/Noncore" comes from the natural gas industry, where federal and state regulatory efforts restructured the industry through the mid-1980s and into the early 1990s. The result of this restructuring was to separate natural gas customers into two broad classes:

- Noncore customers: generally larger customers who were free to purchase their own gas supplies (and later arrange the transport of their natural gas over interstate pipelines); and,

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[5] In crafting any legislation, the Legislature may wish to give the Commission discretion to develop different rules for these smaller utilities. Although AB1890, which restructured California's electric industry starting in 1996, applied to all electric utilities regulated by the Commission, it was drafted almost exclusively to address the three major electric utilities. This resulted in several implementation problems as the Commission sought to apply the legislative requirements to these smaller utilities.

[6] This includes, for example, the Los Angeles Department of Water & Power (LADWP), Sacramento Municipal Utility District (SMUD) and the Modesto, Turlock and Imperial Irrigation Districts.

- Core customers: for whom the incumbent utility would continue to purchase and procure natural gas.

For both groups of customers the incumbent gas utility remains responsible for providing distribution services. Additionally, all customers (both Core and Noncore) must pay non-bypassable charges to fund public purpose programs and to fairly assess the costs of transitioning to the new Core/Noncore market structure (known as Interstate Transition Cost Surcharges or ITCS in the gas industry).

Splitting the natural gas market into a Core and Noncore sector recognizes that large customers are sophisticated energy users, and want increased flexibility to procure their energy needs directly from the marketplace. For smaller customers (i.e. residential and small commercial) energy costs as a percent of their budget are low, and potential savings from shopping around for energy services are small. Additionally, as was seen during the California energy crisis, most small customers place a high value on price certainty and minimizing their exposure to potentially volatile market prices.

A Core/Noncore structure therefore attempts to balance these concerns by allowing large customers the ability to compete in the energy marketplace while smaller customers enjoy the protection of having the incumbent utility meet all of their energy needs.

B. The Relationship of Core/Noncore to Direct Access

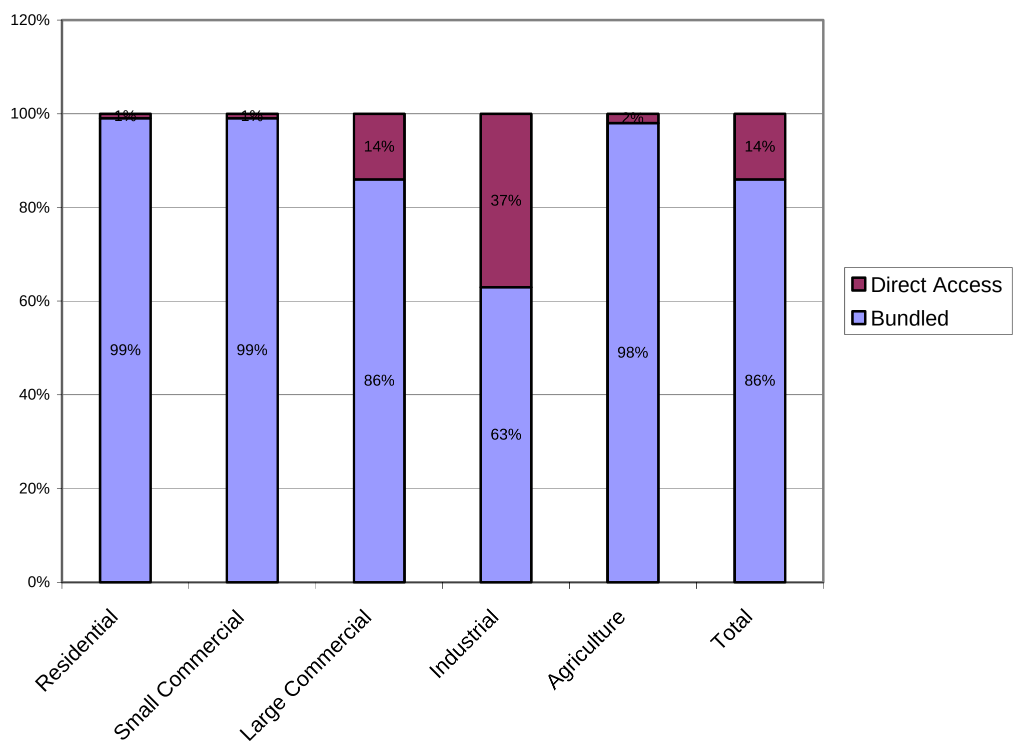
A Core/Noncore market structure is a variant of the Direct Access market structure created by California with the passage of AB1890 in 1996[7]. Building off of California's experience in the natural gas industry, California sought to restructure its electric industry in a similar fashion. Electric customers were given a choice of either having the incumbent utility procure their electric energy (known as "bundled service") or purchasing their energy from a competing provider (known as an Energy Service Provider or ESP).

[7] Stats. Of 1996, Ch. 854.

A major difference between the electric and natural gas restructuring efforts was that on the electric side <u>all</u> customers, not just large ones, had the opportunity to choose a different energy supplier.

Although in theory all customers had a choice of a different energy supplier, actual experience in the electric market shows that it was primarily large customers, with some commercial customers, who chose a competing energy provider. While over 1/3rd of industrial customers (by volume) chose to switch, for example, only about 1% (by volume) of residential customers switched. Almost all of the residential customers choosing to switch did so in order to choose a "green" energy provider offering renewable energy. Very few residential customers appear to have switched as a result of price savings.

SIZE OF DIRECT ACCESS MARKET VARIES BY CLASS



Similar patterns have appeared in other states that have opened up their electric market to competition, although large-scale residential has occurred in some states (i.e. Texas and Pennsylvania).

C. Legislative Issues

Establishment of any Core/Noncore market structure would require that electric customers be allowed to enter into new contracts with ESPs. This would require a change in existing law.

AB1X added Section 80110 to the Water Code. This section requires that:

> "After the passage of such period of time after the effective date of this section as shall be determined by the commission, the right of retail end use customers pursuant to Article 6 … to acquire service from other providers shall be suspended until [DWR] no longer supplies power hereunder."

The last long-term DWR contract is set to expire in 2013.

Currently, there are several legislative proposals that would seek to re-open the Direct Access market prior to the expiration of the DWR contracts.

These legislative proposals include:

- **AB428** (Assy. Richman), which would create a Core/Noncore structure and allow Noncore customers to switch suppliers, provided notice is given.
- **AB416** (Assy. Reyes) which would lift the current suspension on Direct Access
- **AB 2006** (Assy. Speaker Nunez) that, among its other provisions, would allow Noncore customers (500 kW and above) to choose a competitive provider but only if they give 5-years notice of their intent to leave the incumbent utility

In contrast to the above proposals, **SB888** (Sen. Dunn) would largely eliminate Direct Access and restore the existing utilities as the energy provider for all customers.

Based on the legislative interest in addressing the future structure of the electric industry this report takes as its founding premise the notion that some change to the status quo will be made in the coming years. The report assumes that this change will allow customer choice to be reinstated while DWR contracts are still in effect and California is still repaying the debt associated with the electricity crisis.

California, like the rest of the nation, has had a long experience with how traditional regulation of electric utilities has been performed. By contrast, no state has yet to implement a Core/Noncore market structure for its electric industry. Therefore, a review of how such a structure might function would best serve the legislative debate.

Based on the above assumption the report recommends a Core/Noncore market design with specific conditions that must be met as implementation progresses. The report is not an endorsement of the Core/Noncore model; instead, if Core/Noncore is pursued, it is meant to chart the best course forward.

A smooth and careful transition will be critical, and California should learn from the last electric retail reform effort and provide for interim "off-ramps" and potential decision points to defer implementation if needed. Retail choice and substantial Direct Access appears to function relatively well in states with excess capacity, but when tested by tight supply conditions, as in California and recently in Texas, the potential for system instability and economic shock is substantial[8].

D. Current State of the Direct Access Market

In 1994 the Commission issued its Blue Book proposal to open the retail market to competition. This proposal was subsequently implemented into law with the passage of AB1890 in 1996 and on April 1, 1998 California's retail market was opened to competition.

For its first two years of operation, California's market worked reasonably well. Wholesale prices appeared to be competitive, and approximately 14% of load was served by competitive energy service providers (ESPs)[9]. However,

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[8] For instance, Texas Commercial Energy (TCE) was forced into bankruptcy in March 2003 as a result of high prices in the Texas short-term electricity markets. This ESP had been procuring for its load largely from these markets, with insufficient long-term commitments.

[9] See for instance, the annual reports of the ISO's Market Surveillance Committee.

starting in late 2000/early 2001 wholesale prices began to rise exponentially, Direct Access' share of the market dropped from 15% to 2%, and two of California's utilities tottered on the brink of insolvency. In 2001, the State of California was forced to begin purchasing energy to meet the needs of California's customers, through the Department of Water Resources pursuant to SB 6X.

With the passage of AB1X (Statutes of 2000), Direct Access was suspended until DWR was no longer procuring energy. In D.01-09-060 the Commission implemented this suspension. Subsequent to this decision, the Commission has addressed Direct Access rules through several decisions. These decisions have:

- Made Direct Access customers responsible for their share of DWR and utility procurement costs and DWR bond repayment charges incurred during the energy crisis, through implementation of a Cost Responsibility Surcharge (CRS);
- Capped the CRS for Direct Access customers at 2.7 cents/kWh;
- Allowed customers to renew pre-existing contracts and to switch between ESPs; and
- Defined the terms under which customers could assign their pre-existing Direct Access contract rights between locations and accounts.

Although Direct Access had fallen to as low as 2% of total load, Direct Access participation rates rose back to 14%, close to their pre-energy crisis levels, as the energy market stabilized Direct Access

Under current law, the Direct Access suspension ends with the expiration of DWR contracts in 2013. Given recent Commission decisions it appears that some Direct Access load will remain until at least 2013.

CHAPTER 2
Principles Guiding the Analysis

In reviewing the development of any Core/Noncore structure, California should develop a careful, measured and fair transition to opening up the electricity market.

Any Core/Noncore structure, or any market structure reform, should meet the following basic principles.

Symmetric Risk

For Noncore customers who would choose to leave utility service there await potential benefits and risks that depend on how the competitive market is structured. In financial terms, there are "upsides and downsides" to the choice. Fairness suggests that both the upside benefits and downside risks should be borne by the Noncore customer only. This requires that there should be a prohibition on any unjustified cost shifting between Core and Noncore customers and that Core customers be protected from any reliability concerns caused by the actions of Noncore customers.

The Legislature has previously addressed the issue that there should not be any cost shifting between customers as a result of a competitive marketplace.

Legislatively enacted provisions include:

- PU Code § 368 and §370 require that all customers are responsible for certain on-going stranded costs created by the restructuring of the electric industry. These costs include the above market cost of Utility Retained Generation (primarily the above-market cost of Qualifying Facilities contracts)

- PU Code § 366.2 requires that "each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the Department of Water Resources' electricity purchase costs, as well as electricity purchase contract obligations incurred as of the effective date of the act adding

> this section, that are recoverable from electrical corporation customers in [C]ommission-approved rates."

The Commission in its regulatory duties has implemented these requirements. In D.02-11-022, it found Section 366.2(d) relevant, and applied this statutory provision to make Direct Access customers who took bundled service from an electrical corporation on or after February 1, 2001, responsible for paying the DWR ongoing power charge component of the DA CRS. [10]

Additionally, under the Commission's authority, the Commission has also required that all customers be responsible for their fair share of other costs incurred by the utilities, such as monies spent by Edison to procure energy during the energy crisis[11] as well as the costs associated with resolution of PG&E's bankruptcy.

Real Benefits

Any new market structure should deliver real benefits. Any cost savings should be achieved through improved efficiencies and not through the re-allocation of existing costs. As was shown with AB1890, estimated savings may not be achieved. Relative risks and rewards, as well as the probability of them occurring, need to be carefully examined.

Maintaining Reliability

Any structure should ensure that the electrical system can be operated reliably. Reliability must be assured under both short-term conditions (i.e. meeting electric demand in real-time, particularly during periods of peak summer demand) and long-term conditions by ensuring that sufficient capacity is available and that new capacity is added when needed.

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[10] (D.02-11-022, pp. 61-62, 141 [Findings of Fact Law Nos. 11 and 12], & 148 [Conclusion of Law No. 16].)

[11] Edison's Historical Procurement Charge (HPC).

Maintaining Public Purpose Programs

The Legislature has adopted a number of programs that are either funded through rates or implemented by the Commission and/or the utilities it regulates.

The Legislature has recognized that these programs provide benefits to all Californians, and that all Californians should share in paying to support them. Therefore, the Legislature has determined that all customers:

- Should pay for energy efficiency expenditures through a non-bypassable surcharge; and
- Be responsible for meeting the Renewable Portfolio Standards (RPS) implemented by the Legislature.

The Core/Noncore structure analyzed in this report incorporates Public Purpose Programs as an essential component of electric service for all customers in the IOU franchise territories.

CHAPTER 3
Observations on the Current Status of the Electric Industry

A. There is a need for certainty in the short and long term

There is a need for certainty as to the regulatory structure so that timely infrastructure investments will be made

One of the few issues on which all parties seem to agree is the need for certainty. Utilities, customers, and the financial community are all unclear as to the future shape of the California electric market. Certainty regarding the market structure must be established. The Legislature could establish this certainty by: 1) reintegrating the utilities and dismantling Direct Access; 2) declaring that no change will be made to market structure until 2013; or 3) allowing some new form of retail competition.

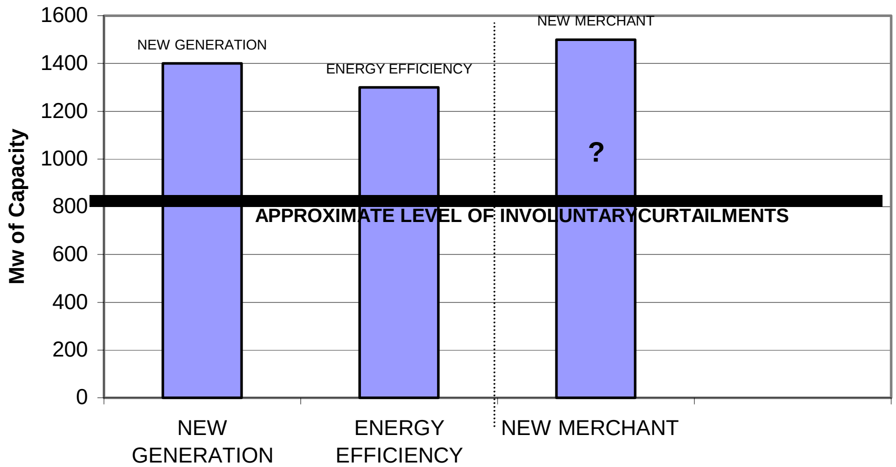
Providing certainty to the market would help all load serving entities (LSEs) to better plan for their energy needs as well as giving both merchant generators and the utilities clearer guidance on their long-term investment strategies. Financial markets also dislike uncertainty, thus making it both more difficult and more expensive to acquire necessary project financing.

A common statement is that one of the causes of California's energy crisis was the market uncertainty that existed between 1994 and 1998 while California first debated, and then implemented its market structure. During this time regulated utilities were reluctant to make new investments in generating capacity such as the 1,500 MW of new capacity the Commission proposed to add to the system through the BRPU process[12]. At the same time, merchant generators were reluctant to invest in new power plants since the market rules were still under development. The transition to a new market structure also significantly reduced the spending on and effectiveness of energy efficiency programs.

[12] D.94-06-051.

One option that would address this problem is to develop a clearly defined strategy to coordinate any transition of procurement responsibility between the utilities and a competitive generation market. Had such a transition strategy been in place during AB1890, California may have avoided some of the reliability and market power problems it faced in the 2000-2001 time-period.[13]

ENERGY RESOURCES AFFECTED BY AB1890 TRANSITION



The Current Supply Situation

The need for certainty is particularly important given California's long-term resource needs. In its recent Procurement decision, the Commission concluded that:

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[13] Even if the 2000-2001 market meltdown had not precluded the private financing of new power plants, the lack of certainty in the new market appears to have delayed entry of new generation into the market in a timely fashion. Ultimately, a significant portion of the new power plants that came on line during the 2000-2002 period were financed in whole or in part by long-term DWR contracts.

"Based on the assessments described above, we conclude that there are ample resources for California to meet demand for 2004 as well as adequate resources available for California to meet peak demand through 2007 although all of these forecasts, particularly in the "out" years, contain some element of uncertainty."[14]

The California Energy Commission, in its Integrated Energy Policy Report reached somewhat similar conclusions (noting a potential need for new resources in 2006) while the California ISO believes that under adverse conditions (for which the probability of these conditions occurring is not determined) could face resource shortfalls in 2005.

The commonly accepted lead-time to site and build new generation within California is 3 to 4 years, although currently there are several projects either already permitted or in various stages of construction that might be able to be on-line within 18 to 24 months if they are able to obtain project financing.

Therefore, regardless of which forecast one relies upon, California has a brief window to determine its retail electric market structure before potentially needing to make new investments in energy resources (either new generation or corresponding energy efficiency/demand response investments) to meet expected demand.

In addition to meeting future growth, certainty in the marketplace would allow California to evaluate the large number of other major resource decisions that the utilities must address in the next 5 to 7 years.

These resource decisions include the upcoming expiration by 2010 of about 1/3rd of the existing contracts with Qualifying Facilities (QFs). Currently, there are about 600 QFs under contract to the utilities that supply power to serve about one-fourth of the combined retail load for the three utilities[15].

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[14] D.04-01-050, p. 19.

[15] D.04-01-050, p. 132.

Expiring QF Contract Capacity

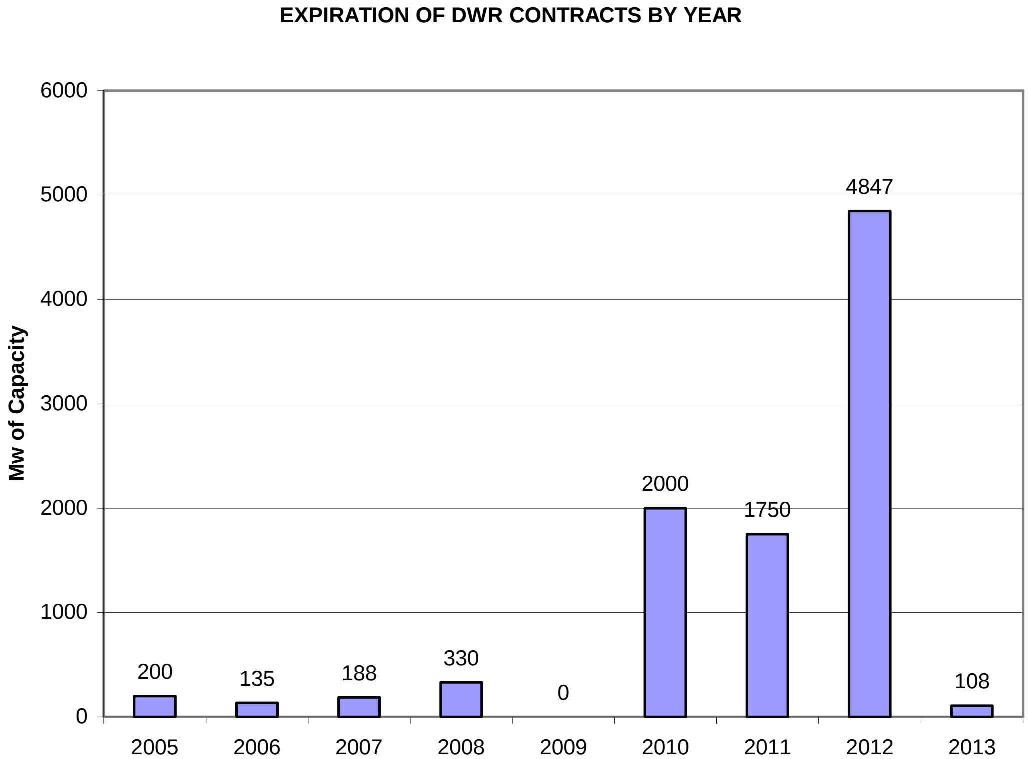
	2005	2006	2007	2008	2009	2010
PG&E QFs	0%	1%	6%	8%	19%	23%
SCE QFs	1%	11%	11%	31%	38%	43%
SDG&E QFs	0%	0%	0%	0%	0%	0%
Combined QFs	1%	6%	8%	19%	28%	32%

The Commission has committed to open rulemakings into how the issue of QF contract expiration should be addressed and appropriate modifications to the pricing methodology by which QFs are paid. In the interim, the Commission has required the utilities to offer new five-year Standard Offer (SO)1 contracts to pre-existing Qualifying Facilities whose existing contract has either expired or will expire prior to January 1, 2006[16].

[16] The QF must have been under contract to the utility at some point after January 1, 1998.

9,000 MW of Long-Term DWR Contracts

Will Expire Between Now and 2012

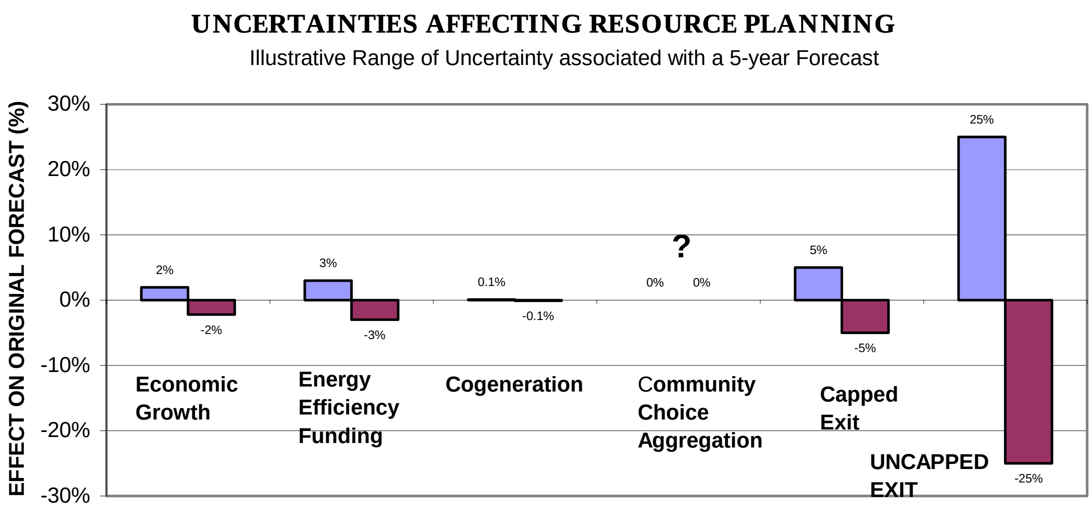


The utilities also need to engage in substantial refurbishment and up-grades to their own generating resources, and make decisions regarding how much and for what time period they should enter into contracts with the approximately 18,000 MW of divested generating capacity.

The utilities need a reasonable degree of certainty as to the amount of load they must plan for to minimize cost and ensure reliability for their customers

The need for certainty is particularly important for the investor-owned utilities that are still responsible for procuring energy for 86% of the customer base (by volume) as well as retaining the legal obligation of being the Provider of Last Resort for all customers, including Direct Access customers returning to bundled service.

Other than weather fluctuations, which are handled through the establishment of planning reserves[17], the uncertainty created by moving to a core/non-core structure is significantly greater than other forecasting risks that the utility must plan for. The following chart identifies the range of uncertainty inherent in a five-year forecast. Most forecast error is in the range of plus or minus 2% over a five-year forecast. Allowing customers above 500 kW to choose a different provider (even without allowing for aggregation) by contrast, introduces a potential forecasting uncertainty of almost 25% of the utility's total load. Even adopting a smaller "capped" amount of customer choice (shown here arbitrarily as 5% of total load) is significantly greater than the other uncertainties that the utility has to plan for.



[17] A hotter than normal summer (i.e. a hot summer that is expected to occur once every ten years) results in peak demand being about 6.1% higher than normal. Utilities usually plan for these occurrences through establishing planning reserve levels that are typically 15-17% above what peak demand would be in a "normal" summer.

If the utility alone bore the financial risk associated with the uncertainty of planning for its resource needs, consumers may be less concerned over any implementation of a core/non-core structure. However, under the recently enacted provisions of PU Code § 454.5[18] (also known as AB57, Wright), the Commission is required to determine in advance the appropriate criteria under which it will allow each utility to recover its reasonable costs in carrying out its procurement plans and activities.

Therefore, if the utility procures energy resources pursuant to a Commission-approved plan, and then loses a significant portion of its customer base, it appears the utility may be entitled to full recovery of its costs. The result would be to either unfairly assign these costs to the remaining bundled customers or collect these costs from all customers (both core and non-core) through some form of surcharge (thus negating the savings that a non-core structure is supposed to provide.) There is also the concern that the uncertainty could encourage the utility to either under-procure its resource needs or over-rely on spot market/short-term purchases, both of which raise reliability concerns.

There are two ways to provide certainty to the utility, as well as all load-serving entities. One is to require each customer to provide sufficient advance notice of his/her desire to leave the utility so that the utility can adjust its resource plan accordingly. Alternatively, the amount of load eligible to switch providers can be capped at a certain amount, thus providing certainty. Both of these options are discussed further under Transition and Implementation Steps.

The need for certainty may bias new resource additions in favor of the existing utilities until the new market structure fully develops

The need for certainty in both the regulatory structure and in the financial markets is likely to favor the existing utilities in financing new resource additions, at least until any new market structure fully develops and matures.

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[18] Stats. 2002, Ch. 850, Sec. 3, (effective September 24, 2002).

New utility-financed generation could be achieved by 10 to 15-year Purchased Power Agreements with merchant generators and/or utility-owned generation.

Even proponents of a Core/Non-core structure note that there is likely to be a relatively long transition period (2-4 years) while new market rules are developed and implemented, and investors feel confident enough that the adopted rules are sufficiently stable so that they can commit to long-term investment decisions. A similar “learning” process appears to have happened when California first opened its market to competition in 1998. As the General Accounting Office noted, over 75% of new merchant power plants in California were not even proposed until 2000-2001, almost two years after the market began operation and almost 4 years after adoption of AB1890[19].

Such a situation may occur again if California re-opens its market. Therefore, in the interim, the existing utilities are likely to be the primary, if not the only entities capable of making major resource commitments. This will be due in large part to their ability to finance their projects with guaranteed cost recovery through electric rates rather than to any inherent efficiency advantage that the utility may have.

Compounding this problem is the current financial state of the merchant generation sector. Almost every merchant generator is under financial distress and some (Enron, Mirant and PG&E’s National Energy Group[20]) are in bankruptcy proceedings.

[19] “Restructured Electricity Markets: Three States' Experiences in Adding Generating Capacity. GAO-02-427 May 24, 2002.

[20] This is the un-regulated affiliate of PG&E.

STANDARD & POOR'S CREDIT RATINGS FOR THE MERCHANT GENERATION SECTOR

	January 2004	
	Rating	**Outlook**
AES	B+	Negative
Allegheny	B	Negative
Aquila	B	Negative
Calpine	B	Negative
Dynegy	B	Negative
EME	B	Negative
El Paso	B	Negative
Mirant	D	-
NEGT	D	-
NRG	B+	Stable
Reliant	B	Negative
Williams	B+	Negative

Note: Ratings range from D to AAA; BBB is the lowest investment-grade rating.

Whereas in the past merchant generators may have been willing to finance new projects based on market expectations, currently financial markets are requiring that merchant generators have long-term contracts in hand prior to offering financing.

A 2004 Standard & Poor's study noted that:

> "In less than 10 years, U.S. energy merchant companies have gone from the cradle to the graveside, if not the grave itself. In the past two years, well over $100 billion of energy merchant market capitalization has disappeared as almost everything that could have gone wrong with the nascent energy merchant industry did… Credit ratings for 12 companies owning more than 200,000 MW of generation worldwide have fallen from investment grade (in most cases) to low non-investment-grade levels. "

While the merchant generators appear to be making some progress toward improving their financial condition by reducing the amount of debt maturing in 2003 from $25 billion to $800 million, they still face nearly $65 billion of loans coming due by the end of 2010 out of a total debt burden of $125 billion.

Compounding the problem of merchant generators financing new projects is the current mismatch between what customers are willing to commit to and what the financial community is seeking. In the electric side, as is true for many customers in the gas side[21], customers are unwilling (for a variety of valid economic and business reasons) to enter into contracts for longer than 1-3 years. Power plant developers (and the investment community upon which they rely), by contrast, are unwilling to invest absent longer-term contracts of 10-15 years. To date, no party has satisfactorily addressed how this temporal gap can be breached so that power plant developers are willing to commit to new capacity.

One option, discussed further in the Transition and Implementation Steps section, is the imposition of resource adequacy requirements. However, while

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[21] The gas market, unlike the electric market has a subset of exceedingly large customers able to make long-term commitments. These customers include, for example, electric power generators, Enhanced Oil Recovery (EOR) customers, oil refiners, and some QFs. These exceedingly large customers often serve as the "anchor tenants" for new pipeline expansions in the same way that Macys or Nordstrom serve as an anchor tenant to help finance new shopping centers. By contrast, few electric customers are comparably sized, and if these customers are more likely to invest in on-site self-/co-generation rather than invest in new power plants.

these requirements help to ensure short-term reliability, their effectiveness at promoting longer-term investment in new capacity is less clear. Another option is the development of a robust futures market for electricity that would allow power plant developers to hedge some of the risk associated with new projects. Futures markets have developed further in the natural gas industry but have yet to effectively develop on the electric side. Additionally, market manipulation of the price indices upon which gas future contracts were traded have lessened the credibility of these markets and significantly reduced their recent use.[22]

B. California Faces an Existing Overhang of Cost and Supply Obligations

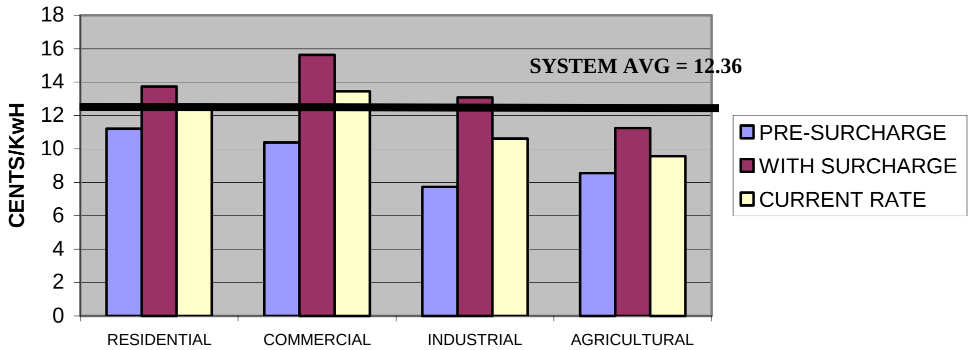
California's electric rates are high. Some components of these rates would continue to be the responsibility of customers choosing Noncore service.

The Commission recently approved rate reductions for both Edison (due to the end of their PROACT collection period) in August, 2003 and for PG&E (as a result of the settlement in their bankruptcy proceeding) in February, 2004.

The result of both of these actions was to significantly reduce rates for customers of these two utilities, albeit rates are still higher than they were before the energy crisis.

[22] FERC Office of Market Oversight and Investigation, *State of the Market Report*.

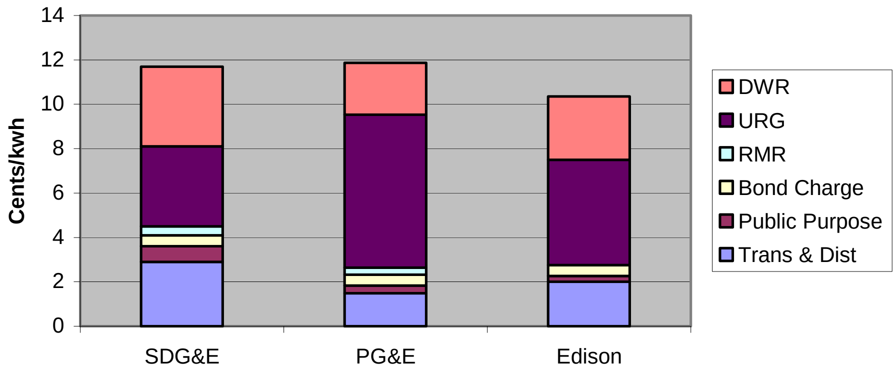
SOUTHERN CALIFORNIA EDISON AVERAGE RATES



Going forward, it is less clear if there are significant opportunities for additional rate reductions. A substantial portion of existing electric rates represents such financial commitments as the DWR bond charges, the cost of long-term DWR contracts, on-going repayment costs associated with the PG&E bankruptcy, and on-going QF contract obligations. None of these costs are avoidable in the near to mid-term. Since existing statutory language precludes shifting these costs between customers, any customers choosing Noncore service would not be relieved of their pre-existing obligation to pay their share of these costs.

Thus any savings from a Core/Noncore structure are likely to appear only if Noncore customers are able to procure energy on the wholesale energy market at a lower price than California's utilities currently do. Other elements of the present rate structure that will persist into the period beyond any creation of a Noncore option include charges for utility retained generation, public purpose programs, nuclear decommissioning, reliability must-run generation, and the like. Some of these rate components are embodied in the Cost Responsibility Surcharge paid by existing Direct Access, while others remain solely the responsibility of customers retaining IOU service.

2004 AVERAGE INDUSTRIAL RATES



Note: Rates for PG&E do not reflect recent 14% reduction approved by the Commission in February 2004.

As the above charts show, a significant portion of the energy-related component of the rate consists of the long-term DWR contracts. Estimated costs for energy supplied under these contracts is approximately $70/Mwh. This level of cost is likely to continue until the DWR contracts begin expiring in 2010.

Another large component of rates is the cost of the utility-retained generation (URG). A significant component of this rate element is the cost of Qualifying Facilities under contract to the utilities. Many of these contracts continue through at least 2010. The remainder of the URG consists primarily of utility owned generation that consists of a mix of resources with costs both above market and significantly below market (such as the hydroelectric resources of PG&E, and to a lesser extent Edison).

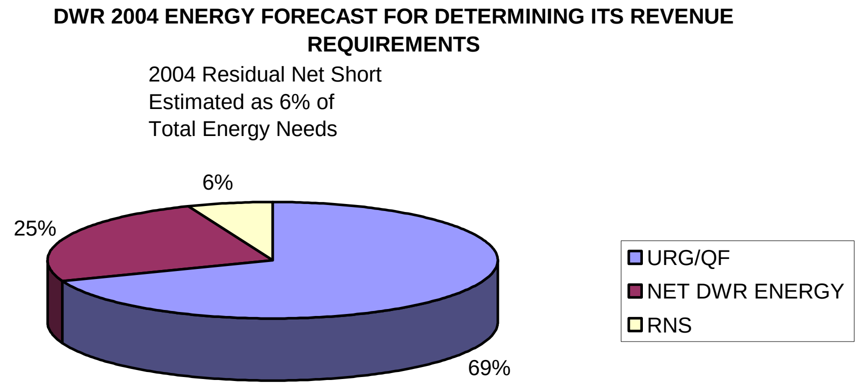
In addition to California's currently high electric rates being largely fixed for the coming years due to on-going financial and contractual commitments, a significant portion of California's energy needs have already been procured for the period 2004-2011. As a result of the energy crisis, the state (through DWR) had to enter into a number of long-term contracts.

When entering into these contracts, DWR assumed that the level of Direct Access load would not exceed 2%.[23] Combined with existing utility-owned

[23] See D.02-11-022.

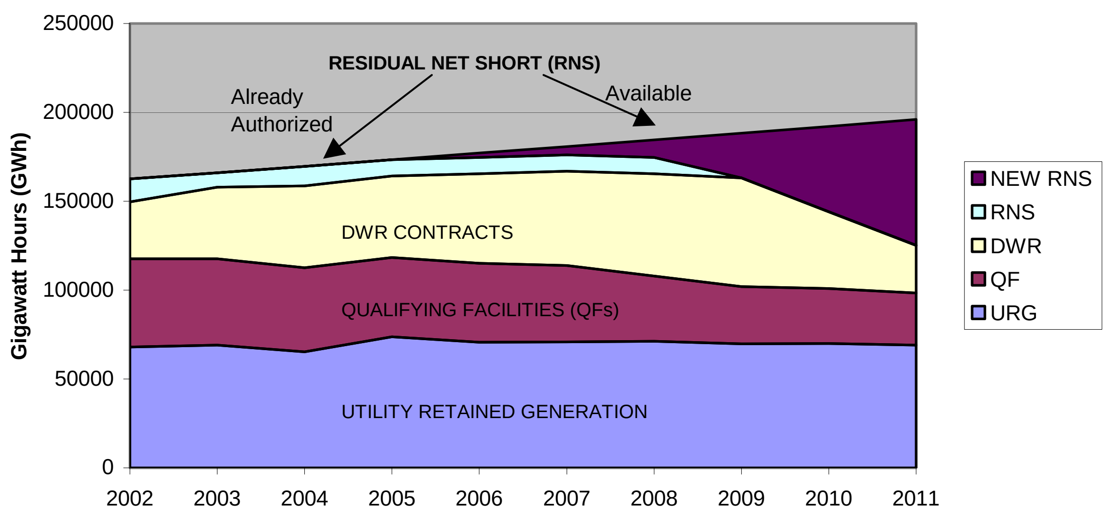
resources and QF contracts, this means that substantially all of the energy needs of the utility's existing customers have already been procured through 2011. The total amount of each utility's need that is not under contract (called the residual net short or RNS) is relatively small.

The following chart shows the amount of energy that is already procured by the utilities to meet the needs of their existing customers for 2004.



This trend continues out through 2009 after which time several of the long-term DWR contracts begin to expire.

RESIDUAL NET SHORT AS A PORTION OF LONG-TERM UTILITY OBLIGATIONS



Compounding the fact that the IOUs have already acquired resources to meet substantially all their needs is the relative distribution of the DWR contracts between the months of the year. As noted by the Commission in D.04-01-050, a significant portion of each utility's RNS capacity needs is concentrated in the time of summer peak demand, while for much of the off-hours and winter seasons the RNS is either close to zero, or in some cases negative (i.e. the utility is selling excess power).

This type of load profile makes it difficult for non-core customers to "back-fill" each utility's RNS needs. Most non-core customers have relatively flat usage patterns and do not match the RNS portfolio. Additionally, it is precisely the times when the RNS is largest (i.e. during the summer peak months) when there is the greatest concern about ensuring that energy resources are available if needed.

The above chart also does not take into account the additional procurement activities that California's utilities have engaged in once they resumed procuring to meet their own energy needs starting on January 1, 2003. In order to ensure reliability, meet reserve requirements, and minimize total costs to ratepayers, the Commission has authorized the utilities to engage in forward contracting to meet 100% of their 2004 RNS needs and to sign up this energy for up to five years.[24]

UTILITY MULTI-YEAR PROCUREMENT ACTIVITIES APPROVED BY THE COMMISSION

D.02-08-071: Gave the utilities transitional procurement authority to procure their forecasted on-peak RNS needs (under a low-case scenario) using multi-year contracts.

D.02-08-071 (renewables): Approved 600 MW of renewable energy resources under contracts ranging from 1 to 15 years to assist the utilities in meeting their Renewable Portfolio Standard (RPS) targets.

D.02-10-062: Approved the utilities 2003 short-term procurement plans "The short-term procurement plans should cover only plans… to procure electricity in 2003 (though the actual power bought or contracted for in 2003 may cover needs for up to five years)."

D.03-08-066: Approved PG&E's request to solicit offers to procure up to 50% of its non-baseload needs for 2004.

D.03-12-059: Approved Edison's request to enter into a long-term Purchased Power Agreement for the 1,054 Mw Mountainview project.

D.03-12-062: Authorized the utilities to enter into contracts with terms up to five years for transactions to meet 2004 needs with delivery beginning in 2004.

D.04-01-050: Requires utilities to offer new five-year Standard Offer (SO) 1 contracts to pre-existing Qualifying Facilities whose existing contract has either expired or will expire prior to January 1, 2006.

The consequence of these activities is to “crowd-out” any discretionary energy purchases that could otherwise be made available to new Noncore customers. As it is, increasing the amount of new Noncore customers could have the effect of further “stranding” existing contractual obligations that the utility has already entered into.

To some extent this may already be happening. Because the DWR contracts do not exactly match when customers actually use power, in some hours and times of the year, the utilities are obligated to purchase more power than they have load to serve and have to resell this excess DWR power onto the spot market. The current level of sales of excess DWR power is already equal to about 50% of the total Direct Access load.

Increasing the size of the Noncore market could require the utilities to sell off more excess DWR power to reflect their newer reduced load. Yet, since the Noncore customers remain responsible for their share of the above-market DWR costs, it is not clear that these customers would receive any savings.

Given recent rulings by FERC, as well as the terms of the contracts, it also appears unlikely that significant renegotiation of these contracts is possible.

It is not until 2009, when substantial amounts of utility contract commitments start to expire, that significant amounts of load could be made available for a Noncore market structure without incurring new sunk costs.

C. There may be other benefits to allowing choice

Allowing customers to choose a different provider, even if there are no discernible price savings, may offer other benefits to the customer.

Commonly cited examples of these benefits include:

- increased flexibility,
- new and different service options, and
- greater perceived control over usage.

As a result of Direct Access, customers were given the opportunity to choose a competitive supplier for other services besides just energy. This included the development of competitive billing options and metering.

Additionally, the availability of customers to switch may incent the utility to better address the concerns of their customers more than they would under a structure where no choice was available.

Allowing choice also provides a potential benchmark to measure the efficiency of utility-provided services.

It is not possible to quantify these savings, but they are of value to customers.

D. Composition of the Core portfolio may change

Under the concept of symmetric risk, Core customers should be protected against any adverse effects from the creation of a Noncore customer class. Existing statutory prohibitions against cost shifting should ensure that costs incurred by Noncore customers are not shifted to the Core.

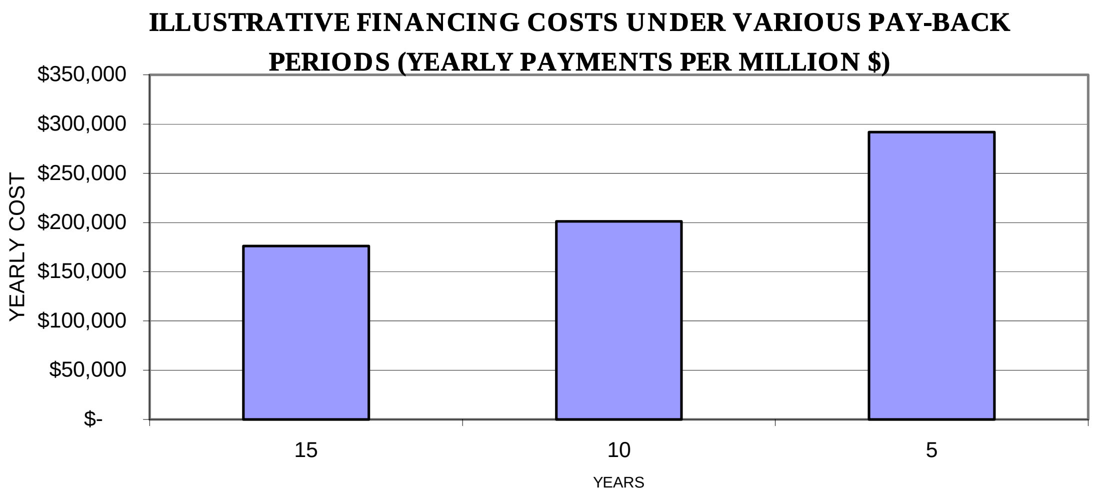
However, even with this safeguard, the potential for customers to switch (even if required to give significantly long advance notice before switching) is likely to bias the portfolio of utility resources toward shorter-term contracts and products. Thus, Core customers could face potentially higher costs and increased price volatility.

Increased potential for switching between Core and Noncore status may also result in the utilities seeking a shorter amortization period for financing new power plant projects. Traditionally, utilities amortized the cost of new power projects for as long as 30 years. Increased switching might lower that period to as short as ten to 15 years, or in some cases five. As the Office of Ratepayer Advocates (ORA) testified in the Procurement proceeding (R.01-10-024):

”Over reliance on shorter-term energy markets can be dangerous, as in the energy crisis, and also does not ensure reasonable cost and rate stability due to potential resource shortages and increased prices with price spikes. While commitments beyond one to five years will be needed, this does not mean that thirty-year commitments are necessary. ORA testifies that ten-year contracts could provide sufficient assurance for market generators to construct new power plants…”

Accelerating the amortization of new power plant construction, however, does increase the price paid for the plant (just as having a 15-year instead of 30-year home mortgage increases its monthly cost).

The following chart provides illustrative monthly payments for a new power plant over various amortization periods. Shortening the amortization period increases yearly costs.



Finally, it is unclear if increasing the size of the Noncore market is good or bad for Core customers. Some economists believe that the larger the share of a market a utility has, the easier it is for the utility to exercise monopsony power as the only buyer, thus getting better deals in the wholesale energy market. Others believe that expanding the amount of both buyers and sellers is a better method of increasing efficiency and cost savings in the wholesale energy market.

E. The infrastructure already exists to support Direct Access

California already has in place the infrastructure needed to create a Core/Noncore market structure. Almost this entire infrastructure was put in place when California implemented Direct Access as a result of AB1890.

This infrastructure includes:

- A functioning ISO to handle wholesale energy transactions;
- The development of Scheduling Coordinators (SCs) who serve as middlemen matching purchases on the wholesale market with demand for energy from ESPs;
- "Unbundled" rate design that allows customers to clearly identify the various components of the total energy bill and which portions of the bill are open to competition;
- Established utility rules on how ESPs and DA customers are billed; and,
- A process by which customers can switch service (Rule 22).

As a result of Direct Access being in effect since 1998, the utilities have developed the necessary interfaces between the ESPs and the utilities so that information on issues such as billing and switching ESPs can be handled. This is not to say that all of these functions have worked flawlessly since the inception of Direct Access. For example, coordinating of billing between the ESPs and the utilities appears to be an on-going problem. Nonetheless the rules and structures governing these areas of retail competition are in place.

Additionally, the Commission has pre-existing legal authority over ESPs as a result of SB477. For example, the Commission has the authority to set technical and operational standards for ESPs providing service to any Direct Access customer (PU Code 394). To these requirements should be added the recently adopted requirement that all LSEs under Commission jurisdiction must meet reserve and resource adequacy requirements (D.04-01-050). From the standpoint of these issues at least, establishing a Core/Noncore structure would not require significant time or resources.

Achievement of the necessary infrastructure for Direct Access did impose a substantial up-front cost that should largely be considered sunk.[25] The on-

[25] These costs included $250 million to establish the ISO (currently being repaid by all customers through the ISO's transmission rates; $90 million consumer education program; and $90 million in utility –incurred implementation costs (PUCode 376).

going variable costs associated with re-instituting a Core/Noncore structure, however, should be evaluated.

For example, the yearly operating cost of the ISO ($220 million) represents about 1-2% of the total wholesale market price for electricity. About ½ of this cost appears to be associated with the complex scheduling, billing, and settlement processes that a competitive marketplace requires.[26] To these costs should be added equivalent costs incurred by the utilities and ESPs to interact with these processes.

The cost of these market structures needs to be factored in when evaluating the future of any Core/Noncore structure. This analysis is beyond the scope of this report, but should be considered in the going-forward debate regarding Core/Noncore.

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[26] In its 2004 Grid Management Charge proceeding (GMC), which is analogous to a utility General Rate Case, the ISO conducted a functionalized study of its operations. While about half of its costs were classified as reliability-related (i.e. costs that would have to be incurred for reliability reasons regardless of market structure), most of the remaining ½ of ISO costs were associated with scheduling/billing.

Chapter 4

Recommended Transition and Implementation Steps to a Core/Noncore Structure

The challenge faced by this report is to design a Core/Noncore market structure that is responsive to the needs of California's ratepayers and its electricity system following the energy crisis. Building from this foundation, the following transition steps are recommended if a Core/Noncore structure is pursued.

1) Ensure Resource Adequacy Requirements Are Met

The Commission established in its recent Procurement decision, D.04-01-050, that all load-serving entities (LSEs) in the IOU franchise territories must demonstrate the ability to meet 115-117% of the peak load for which they are responsible. This requirement is to be met by January 2008, with specific milestones and assessment methods to be developed by the Commission this year. Meeting this requirement should be a precondition to the creation of a Noncore market.

The ramping up of these reserve levels will help to ensure that existing and any future Direct Access customers are adequately provided for, and procurement for bundled customers not relied upon to meet non-IOU load.

As these standards are implemented the Commission will gain valuable insight into the strength of ESPs and their ability to secure firm resources. This insight, in turn, will allow the Commission to assess the extent to which ESPs will be able to expand service to a Noncore market while maintaining resource sufficiency. It will take some time before ESPs can demonstrate this level of resource adequacy, a time period that may define the transition to a potential Core/Noncore market.

Options for Meeting the Resource Adequacy Requirement

The Commission has established that resource adequacy and appropriate reserves must be secured for all load in the IOU franchise territories. In light of California's need for generation resources in the near future, this is a sound principle that no Core/Noncore structure should violate. To that end the following options are available:

1) *ESPs must meet all the needs, including reserves, of the load they serve.*

In this option the entire burden is placed on the ESP, subject to confirmation by the Commission that the ESP has met its targets. The extent to which ESPs will meet this challenge, and how long it will take to meet it, cannot be known in advance. Noncore exit may therefore be delayed by an unforeseeable period.

2) *IOUs provide for all the generation needs of customers in their territories.*

This is effectively the *status quo* option, limiting ESP service to the Noncore to functions such as billing and energy management.

3) *IOUs provide capacity and reserves for certain Noncore customers; other Noncore customers have all generation needs met by ESPs, provided these ESPs meet the resource adequacy standard.*

This option creates two categories of Noncore service. The first, "Capacity-Assured Noncore," allows Noncore customers to procure energy competitively from the ESP, while paying for and receiving capacity services, including reserves, from the IOU. The second, "Capacity-Independent Noncore," allows the Noncore customer to exit IOU service completely, but requires that the ESP providing service in this category demonstrate resource adequacy up to the full 115-117% level.

Again, it cannot be known in advance how long it will take before ESPs can demonstrate this level of resource adequacy; the Capacity-Independent Noncore option may not be available, therefore, by the time of first Noncore exit. Capacity-Independent Noncore customers may be subject to interruption if the ESP fails to provide adequate generation in real time.

Demonstrated resource adequacy should be a precondition to the creation of a Core/Noncore structure

Recommendations

We recommend option three, with two categories of Noncore service, as the best means of ensuring resource adequacy in a system of retail choice. Capacity-Assured Noncore customers should bear the full cost of IOU capacity services, and may test the proposition that energy can be procured more cheaply outside of the utility system. Capacity-Independent Noncore customers would be responsible for the Cost Responsibility Surcharge, reflecting the full share of their obligations, but not for the costs associated with further capacity and energy services from the utility. We recommend that Capacity-Independent Noncore customers be physically interruptible to the fullest extent possible, should their ESPs fail to provide service.

Under either option the relevant LSE would be required to demonstrate resource adequacy on the schedule established by the Commission. Demonstrated resource adequacy should be a milestone that must be achieved prior to actual Noncore customer exit.

2) Coordinate Noncore Exit with Expiration of Utility Contract Commitments and the IOU Planning Process

Potential Noncore customers should be required to declare their interest in leaving utility service on a schedule that allows the IOU's to plan for the commitment to new resources

The IOUs are presently on two-year planning cycles before the Commission. In order to avoid the creation of new stranded costs and the financial risks to bundled ratepayers these costs pose, potential Noncore customers should be required to declare their interest in leaving utility service on a schedule that allows the IOU's to plan for the commitment to new resources. The method of determining which customers are allowed to exit – such as an auction, random selection, or on a first-come basis – will require further study.

Significant care must be exercised during the transition period so that existing generation supply does not have incentives either to cease operation, be acquired to serve non-California load, or be consolidated in a wholesale market structure that results in an increase in market power.

Options for Coordinating Noncore Exit with IOU Procurement

1) The "Big Bang"

In this approach eligible customers are given the option of leaving utility service at a defined point in time, after which all remaining customers would be locked in to utility service going forward.

2) Timing Noncore exits with expiring IOU commitments.

The established process of IOU long-term planning should allow the Commission to determine the amount of expiring generation under contract in a given year, which could be interpreted as an amount of Noncore load that could leave utility service without imposing new sunk costs. This amount of exiting load could be made available to Noncore customers and corresponding ESPs via an allocation method to be determined by the Commission.

3) Allowing Noncore exits regardless of expiring IOU commitments.

A Noncore "open season" could allow exit from utility service without regard to sunk costs.

4) Allowing Noncore exit up to a cap.

Noncore exit could be capped at some level higher than the expiring utility commitments, and a CRS recalculated to reflect a fair share allocation of sunk costs.

Recommendation

The transition period leading up to 2009 provides a period of time for the IOUs to adjust their procurement strategies to avoid making investments on behalf of departing Noncore load. The precise timing of this coordination is essential in avoiding new sunk costs, costs that should be passed on to Noncore customers via the CRS, and is one of the most challenging elements in designing a Core/Noncore structure.

The "big bang" approach creates a "now or never" framework and increases the likelihood that Noncore customers will jump at the opportunity without fully weighing the potential risks and rewards. This could subsequently result in pressure to allow return to utility service if those rewards fall short of expectations, threatening the utility's ability to procure for bundled customers. Moreover, the requirement that resource adequacy be established prior to Noncore exit limits the feasibility of this approach.

An uncapped potential exit level allows for a much greater amount of sunk costs. This approach poses a risk to utility finances and procurement strategies, risk which may ultimately be borne by bundled ratepayers.

While not avoiding incurring new sunk costs, an approach that caps Noncore exit at some level higher than the utility's expiring contract commitments would limit these threats to ratepayers, the utility, and to market stability in general.

We recommend timing Noncore exit with expiring utility contract commitments, allowing the first Noncore exit to take place in 2009, with the first substantial opportunity for exit coinciding with the end of DWR contracts in 2010. This approach caps the amount of exit at approximately 2000 MW in 2010, approximately 2000 MW in 2011, and approximately 5,000 MW in 2012[27]. The

[27] This could potentially increase the size of the Direct Access market by 45% by 201010, increasing its potential share of the total electric market to 20%. By 2012, the total size of the Direct Access market could be as large as 30% of the total market.

amount of available exit in 2009 will be a function of expiring QF contracts, renewal of which may be desirable for reasons of efficiency and resource diversity, and short-term IOU contracts recently authorized by the Commission. The Commission should determine the precise amount of this load available for Noncore status, and establish a method of allocating it to potential Noncore customers in time to coordinate with the IOU planning cycles, i.e. the 2006 planning period.

This timing will also allow the utility to make reasonable investment decisions for its Core customers in the 2006 long-term planning cycle previously established by the Commission.

Potential Noncore customers would declare their desire to select either the Capacity-Assured or Capacity-Independent Noncore options. Subsequent to the allocation of the available Megawatts for 2009 exit, the IOUs would prepare their 2006 long-term plans to reflect their new procurement obligations. This approach minimizes the creation of new sunk costs, ensures the fair share allocation of procurement costs, and allows for a significant increase in the amount of available retail choice.

Between now and March 2006 the Commission should determine the precise amount of load available to Noncore customers in the years 2009-2013, calculate the appropriate Cost Responsibility Surcharge (CRS) for customers leaving in 2009, rationalize bundled ratemaking to allow potential Noncore customers to make economically efficient decisions, and establish key Provider of Last Resort provisions (described below).

3) Establish the IOU as Provider of Last Resort (POLR) with Two Categories of Service

A source of substantial risk to California and to bundled ratepayers in the Core/Noncore structure lies in the potential for unexpected customer swings back from the Noncore to utility service. Noncore customers who return to utility service should be required to give adequate notice to coordinate with IOU planning, or risk facing high spot market prices for electric service and possible interruption.

As a manifestation of symmetric risk, Noncore customers should not be permitted to move back and forth freely between utility and ESP service, responding to short-term swings in the price of electricity from each provider. Absent specific extenuating circumstances, such as the failure of the ESP to provide service on any terms, Noncore customers should be required to remain outside utility service for a period of time sufficient to limit threats to the stability of the Core's procurement portfolio, the process of developing new infrastructure, and the market in general. Rules that govern subsequent return to utility service will limit gaming of the Core/Noncore structure by Noncore customers.

The utility should remain the Provider of Last Resort with two categories of Noncore service, minimizing risk to bundled customers while allowing different degrees of choice

Role of the Provider of Last Resort

Provisions must be in place to prevent reliability problems from spilling into Core service in the event of resource inadequacy on the part of an ESP. Dividing the electricity system for purposes of allowing limited competition in retail service cannot mask the fact that, absent stringent physical interruptibility standards, the grid remains an integrated whole. If these inadequacies persist and the ESP can no longer serve the Noncore customer, provisions must also be made to serve the returning customer on a longer-term basis, in recognition of the importance of electric service to California's economy. This backstop function is delivered by the Provider of Last Resort (POLR) in other restructured markets.

The terms and conditions of POLR service, including the length of time the service can be accessed and the process for transitioning out of POLR service to another ESP or back to the utility, should be clear and enforceable before a Core/Noncore structure is implemented.

The Commission and Noncore customers must be aware of the significantly increased costs that a returning customer could face in taking POLR service that is procured from spot markets, as could occur if a returning customer cannot be quickly reintegrated into the utility's portfolio. Had such a regime been in place during California's energy crisis, for example, returning customers could have faced prices in the $200-300/Mwh range. Additionally, POLR arrangements may specify only a "best efforts" to obtain energy. During times of tight supply, POLR providers may be unable to procure power at any price, and these Capacity-Independent Noncore customers may be interrupted. This could have significant economic repercussions for California.

Should this circumstance materialize we would expect significant pressure to allow returning Noncore customers to access the Core generation portfolio outside of the established procurement planning framework. Such an eventuality could represent cost shifting from the Noncore to the Core, and could potentially spread resource adequacy problems beyond the competitive segment of the retail market.

In theory the possibility of having to faces high POLR rates based on spot market prices will encourage Noncore customers to examine closely the resource adequacy and general stability of the ESP with which they contract. This heightened scrutiny, again in theory, should favor ESPs that can demonstrate such resources, at the expense of those more likely to fail.

In practice, however, it may be difficult to impute such diligence to Noncore customers considering ESP options. POLR services and rates may not enter into the decision of a customer to leave utility service.

In this case the risk that ESPs may fail, and POLR service may subsequently be called upon, increase. If POLR service is provided by the regulated utility, this in turn increases the risk that Core customers will ultimately provide the resource adequacy, and bear the financial cost, to provide POLR service.

A liquid spot market of excess generation is present in Texas as well as in other prominent restructured states such as Massachusetts and New Jersey, providing a substantial buffer to swings between competitive and utility-provided generation.[28]

In a market with tighter margins, however, there is little if any buffer, and the burden of market monitoring to ensure sufficient capacity is increased. This

[28] The reserve margin in Texas is estimated to be in the range of 33-40%. Massachusetts is expected to have substantial overcapacity for the next five years, reaching 33% in the next few years; New Jersey's margin is more than 20%. California, in contrast, is implementing a plan to achieve 15-17% reserves by 2008.

concern may be mitigated if ESPs demonstrate ability and willingness to secure firm resources, stimulating the construction of new generation, as opposed to reliance on spot market surpluses that may not exist in future years. Our research up to this point does not indicate that this stimulus is taking place.[29] Observing the generation market in California and elsewhere in the coming years should provide clearer indication on this important point.

In the interim it is enforcement of the strict resource adequacy requirements for all LSEs that is California's best hope of ensuring sufficient generation in a Core/Noncore structure.

Options for POLR Service – POLR Provision

In restructured markets the role of the Provider of Last Resort is generally played by the utility, although competitive auctions have been established in some jurisdictions to determine how POLR service will be provided.

1) *POLR Service by the IOU*.

If the utility is designated to provide POLR service, it can do so either through its own generation assets, via competitive procurement, or some combination of operated and contracted sources.

Rhode Island places the obligation on the utility, but requires that it procure POLR power competitively from merchant generators.

Ohio has established provisions whereby the distribution utility provides POLR service at prices based on the competitive solicitations used to serve the needs of the utility's entire customer base.

2) *POLR Service by an ESP or third party*.

Texas has established a system whereby an auction determines the provider of POLR service. POLR service in Texas is provided at a Commission-

[29] For instance, Texas Commercial Energy (TCE) was forced into bankruptcy in March 2003 as a result of high prices in the Texas short-term electricity markets. This ESP had been procuring for its load largely from these markets, with insufficient long-term commitments.

approved price, by different entities serving residential, small non-residential, and large non-residential customers.

By design the Texas system can support POLR provision by any entity. In practice, however, POLR service in Texas has thus far been provided by IOU-affiliated entities operating outside of the IOU's service territory.

Options for POLR Provision – Coordination with IOU Procurement

We recommend above that the Noncore be divided into two categories, Capacity-Assured and Capacity-Independent. These categories have different implications for coordination of POLR service provision with IOU procurement for Core customers.

1) *Coordination with Capacity-Assured Noncore provision*

Capacity-Assured Noncore customers that return to utility service for both energy and capacity face the following options:

a. *Long-term commitment to full utility service.* Insofar as the Noncore customer has been paying to receive capacity services from the utility, the customer can be integrated into full utility service on short notice at bundled rates.

b. *Transitioning to a new ESP*. Again, the Capacity-Assured Noncore customer has paid to receive capacity services, and should be eligible to receive energy from the utility for a limited period of time before selecting a new ESP. The length of this interim period should be subject to further study.

c. *Choosing Capacity-Independent Noncore service.* Noncore customers that wish to fully exit utility service could coordinate with utility procurement and minimize sunk costs by timing their exit with expiring utility commitments. Alternatively these customers would face a potentially higher CRS to reflect the resource commitments previously made on their behalf.

By design, with the Capacity-Independent Noncore customer severing all ties to the utility, there is no alternative to the real-time provision of energy if POLR service is required

2) Coordination with Capacity-Independent Noncore provision

a. *Establish a "best efforts" standard of utility procurement for POLR service to Capacity-Independent Noncore customers.* The utility will not have made any provisions to secure capacity for these customers, and so, in the event that the customer's ESP fails to procure on its behalf, the utility will be forced to make arrangements in real time. By design – with the Noncore customer severing all ties to the utility – there is no alternative to this real-time provision of energy. The utility may be able to absorb the returning load without incident, or the utility may be unable to procure for the returning customer under any circumstances. There are options, however, in how to address generation shortages in this instance.

b. *Allow these shortages to influence service to Core customers.* This option may involve the curtailment of load throughout the IOU service territory.

c. *Require that Capacity-Independent Noncore customers be physically interruptible.* This option requires advanced metering and remote interruption capabilities to prevent resource inadequacies originating in the Noncore from influencing Core service.

d. *Allow Capacity-Independent Noncore customers to return to utility service.* The Capacity-Independent Noncore customer could be allowed to return to utility service on a schedule coordinated with the utility's procurement planning.

Recommendations

Enforce resource adequacy requirements to minimize the need for POLR service.

In states where restructuring is claimed to be successful, such as Texas, Massachusetts, and New Jersey, the POLR backstopping service is provided in a context of substantial excess generating capacity. California does not presently possess this excess capacity, and until or unless it does, the design of POLR service must stimulate sufficient resource development, in order that the state may reach a point where capacity is sufficient to test the propositions of the competitive market.

Establish the IOU as Provider of Last Resort.

Under California law the investor-owned utilities are effectively the Providers of Last Resort in their territories, and, as demonstrated during the electricity crisis, IOU customers expect them to play this role regardless of the existence of retail choice[30]. This study therefore recommends that the utility provide POLR service in any Core/Noncore structure that is created, subject to distinctions arising from the separation of Noncore service into two categories.

Allow Capacity-Assured Noncore customers to take POLR service at bundled rates for a specified period.

Capacity-Assured Noncore customers are required to bear the full cost to the utility of providing capacity that is dedicated to those customers. To the extent that the utility procures this capacity, Noncore customers in this category should be able to return to utility service for some period at bundled rates. The length of time the Capacity-Assured Noncore customer should be allowed to receive this service should be the subject of further study.

Establish a "best efforts" standard for POLR service to Capacity-Independent Noncore customers, with physical interruptibility.

No provisions will have been made by the utility for the needs of this category of Noncore customers. Consequently, the utility as POLR service provider will be forced to make real-time arrangements to meet these generation needs, which may entail high-priced spot market purchases. The cost of these purchases should be borne by the Capacity-Independent Noncore customer only, and in the event that provisions cannot be made, these customers should be subject to physical interruptibility. Capacity-Independent Noncore customers should be allowed to reestablish utility service on a schedule that coordinates with the utility's procurement planning.

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[30] At the height of the electricity crisis, the state itself stepped in to serve in the POLR role. This resulted largely from the financial inability of the IOUs to procure power under the frozen rate structure imposed by AB 1890. Under this recommendation, POLR service would be provided at a rate that adequately compensates the IOU for providing the service.

4) Establish a Fair Cost Responsibility Surcharge for Noncore Customers

The Commission's present method of allocating non-bypassable charges to Direct Access customers is via the Cost Responsibility Surcharge. Setting a fixed CRS will be important in establishing the competitive dynamics of the Core/Noncore market. Prospective Noncore customers will need to know their CRS obligations before they can make an informed choice regarding the price benefits of leaving utility service. A CRS that may fluctuate will potentially create enough uncertainty to deter customers from choosing Noncore status. Similarly, a CRS that fluctuates to absorb the difference between Noncore service prices and some predetermined "market price," as in the AB 1890 approach to Competition Transition Charges, could eliminate any benefits to Noncore status that may exist.

At the same time, the present capped Cost Responsibility Surcharge creates deferred financial obligations to which Core customers will ultimately be entitled, to be repaid with interest. Each customer taking service with a capped CRS increases the financial burden on bundled customers. Allowing more customers to leave at a capped CRS therefore creates further deferred financial obligations, which must be spread over a shrinking number of bundled customers.

Options in Establishing a Noncore CRS

1) Retain the existing CRS cap of 2.7 cents

The Commission arrived at the 2.7-cent cap as representing a substantial portion of the share of sunk costs attributable to Direct Access customers. Payment of this capped CRS would result in bundled customers being largely "made whole" by the time the bulk of DWR contracts terminate in 2011. While the precise effect on bundled customers would require further calculation, the Commission could permit further exit from utility service by Noncore customers under a CRS capped at the present level.

2) Reset the CRS to reflect the full share of sunk costs associated with Noncore customers.

Alternatively, the Commission could recalculate the CRS to reflect the full share of sunk costs attributable to the Noncore, including new obligations undertaken by the utilities since the suspension of Direct Access. While this would represent a full fair share allocation and lessen the burden on bundled ratepayers, the effects on the viability of the Noncore market are unknowable in advance.

Recommendations

The potential size of the Noncore market described here – a total of 9,000 MW by 2012 – represents roughly a doubling of the present Direct Access market. Allowing Noncore exit under the capped CRS would therefore result in substantial cost shifting to a shrinking amount of bundled customers. This is an untenable situation, and we therefore recommend that Noncore customers pay an uncapped CRS reflecting their full cost responsibility.

Financial commitments made on the part of bundled customers since the suspension of Direct Access – the point from which the original CRS was calculated – should also be added to the CRS of Noncore customers. This new CRS should be fixed for a predetermined period of time, to enable Noncore customers to make an informed choice regarding the relative merits of utility and Noncore service. Presently bundled customers choosing Noncore service may also be owed their accrued portion of the deferred obligations resulting from the capped CRS. Precisely how these customers could be credited in the proper amount would require further study.

It may be possible to allow a Noncore customer to pay a one-time exit fee that would cover its projected total contributions in the form of an uncapped CRS. This amount should properly be reduced via an appropriate discount rate to arrive at its net present value. Further study should be conducted on this point in advance of the first Noncore exit in 2009.

Noncore customers should pay a Cost Responsibility Surcharge that encompasses the full share of their obligations

5) Make Noncore Status Optional and Initially Available Only to Customers 500 kW and Above; "Grandfather" Existing Direct Access into Noncore Status

As has been shown in other states and countries that have chosen to restructure their electric industry, it has been large customers who have predominantly chosen Direct Access. Therefore, under an orderly transition to a CNC structure, it appears appropriate to limit participation to some subset of larger customers. The question that must be answered is what is the appropriate size threshold for allowing customer choice.

Options in Establishing a Size Threshold for Noncore Status

1) A starting threshold for customer choice appears to be to allow customers with a maximum peak demand of greater than 500 kW to be able to choose their competitive provider. This range corresponds to the large industrial customer tariffs of the utilities (Edison's TOU-8 and PG&E's E-19/E-20 rates). These customers are the largest users, are sophisticated and knowledgeable about their energy usage, and contain a large number of manufacturing customers. All of these customers have been on mandatory time-of-use rates since the early 1980's and thus have experience with the hourly and seasonal fluctuation in energy prices. These customers represent over 2/3rds of the current direct access load.

2) A slightly lower threshold of 200 kW has also been proposed. This is the customer size for taxpayer-funded CEC installation of real-time meters for all customers pursuant to the requirements of ABX1 29. Many of the customers with demand between 200 and 500 kW would be expected to be large, sophisticated energy users as well,

3) As the size threshold is progressively lowered below 200 kW, the amount of eligible customers (both in terms of number and percent of total utility load) begins to increase significantly.

Noncore status should be optional, and initially reserved for customers 500 kW and above. Existing Direct Access customers should be grandfathered into Noncore status

Other size thresholds that have been proposed include:

- 50 kW -- This is the size at which customers choosing Direct Access under AB1890 were required to acquire a real-time meter; or

- 20 kW – This was the initial divide approved in AB1890 between residential and small commercial customers and large commercial/industrial customers. 96% of current Direct Access load is 20 kW or above.

Recommendations

In setting the size threshold at which customers could be allowed to choose, there are three main policy criteria.

First, the larger the class of customers allowed to choose, the greater the uncertainty over the amount of load for which the incumbent utility is responsible, and the broader the impacts of any reform failure.

Looking at Southern California Edison, as an example, setting the size threshold at 500 kW would mean that approximately 23% of its existing bundled service load would be allowed to switch. Lowering the threshold to 200 kW increases this to approximately 34% of Edison's current bundled load.

Therefore, even limiting Noncore eligibility to just the larger customers (200 kW or 500 kW) introduces a significant amount of uncertainty into Edison's resource planning to meet its bundled customer needs. This uncertainty increases the risk of stranded costs for unnecessary investments, for which bundled customers may be responsible, or insufficient investment to meet customer need, and the attendant reliability problems that may result.

Extending the definition of Noncore down to even lower thresholds (20 kW or 50 kW) would even further increase the amount of load that the utility would not be sure it was responsible for planning for, compounding the risks described above.

A second important criterion in determining the appropriate size threshold is the ability to monitor energy usage by those customers choosing Noncore status. Critical to ensuring the reliability of the electric system in real time is ensuring that ESPs providing service to Noncore and Direct Access customers provide sufficient energy to the system during peak periods. Otherwise, there is a threat that insufficient resources could jeopardize system reliability and increase the risk of involuntary load curtailments. It also leads to the potential for cross-subsidization, as Noncore customers lean on utility-provided generation during peak time periods.

The ability to monitor energy usage in real-time of Noncore customers thus argues for setting the level at which customers can choose Noncore service to 1) 200 kW and above – the level for which the CEC has installed real-time meters or 2) 50 kW or above with the requirement that each customer choosing Noncore service acquire a real-time meter. (This rule is identical to the rules in effect during Direct Access).

Noncore service could be defined even more broadly to include any customer who wants to choose Direct Access, regardless of size, if the customer agrees to install a real-time meter. This raises planning problems, however, as described below, and is not recommended. Additionally, at lower size levels, the cost of installing a real-time meter is likely to exceed any benefits from being a Noncore customer.[31]

Finally, given the above recommendation that Noncore exit be capped at the level of expiring utility contract commitments, there is the important consideration of apportioning the opportunity to receive the potential benefits of Noncore status. A major motivation behind the Core/Noncore debate appears to be a concern over large industrial customers leaving California. To the extent this belief is warranted, California should consider the impact a size threshold would have on addressing this potential problem.

We recommend that the opportunity created for exiting utility service by expiring utility contracts should be allocated first to customers with a minimum of 500 kW peak load. This category includes the large industrial customers most likely to leave California because of high electricity costs, threatening the state's jobs and tax bases, and contains a customer class whose energy use can be most effectively monitored in real time. We recommend that this threshold be employed for the first "open season," in the 2006 IOU planning cycle. If the load allocated at that time for 2009 exit is not fully subscribed by the 500 kW customer

[31] During the implementation of AB1890, the CEC argued that installing real-time meters for Direct Access load could be cost-justified down to the 20 kW level, a position the Commission did not adopt. The cost-effectiveness should be up-dated to reflect changes in energy costs and metering technologies.

class, consideration should be given to lowering the size threshold. Any customer eligible for Noncore status should have a real-time meter.

Options in Establishing Certainty of Participation Levels

California must also decide whether participation in the Noncore will be optional or mandatory.

1) *Make Noncore status mandatory for all size-eligible customers.*

This approach has the advantage of establishing with certainty the amount of load that will leave utility service, making the procurement planning process easier and less risky for bundled customers.

2) *Allow eligible customers the choice of Noncore status.*

The gas industry offers the example of "Core subscription," in which large gas customers, eligible to receive competitive service, elect to remain with utility procurement. This approach allows large customers to match their tolerance for risk with a level of price and service certainty. The value of certainty for the utility and its bundled customers, however, is not provided by this option.

Recommendations

The idea that large customers would be forced to engage the uncertainty of market transformation and competitive service does not sit well with consumers still reeling from the electricity crisis. As one representative of large California industry put it, Noncore customers want to be "pulled" into competitive service by attractive deals, not "pushed" in by legislative or regulatory fiat.

As noted, making Noncore status optional does not provide the same level of certainty to the IOU, and therefore requires careful coordination with IOU resource planning. Above we describe a method of coordination that utilizes expiring utility contracts to define the amount of Noncore exit to be allowed in a given period. A larger amount of exit would create utility sunk costs that would, in fairness, follow the departing customer as part of a CRS. While these are challenging implementation details, they are preferable to the threat of forced exit by eligible customers, and the uncertainty regarding cost, service and resource adequacy such a forced process would entail.

Perceptions of the value of choice are some of the main reasons California is considering a Core/Noncore structure now. In our view choice should extend to participation in the Noncore, and we recommend that Noncore status for eligible customers be optional.

Options in Treating Existing DA Customers in a Noncore Structure

Establishing a consumption-level threshold for qualification for Noncore status is likely to leave some existing Direct Access customers outside the Core/Noncore structure. The Commission has implemented the Legislature's direction to allow existing DA customers to remain with ESPs, subject to certain conditions. Establishing a Core/Noncore structure would require consideration of how to treat those existing DA customers who continue to meet the legal standards required to retain their status.

1) *Withdraw DA status for customers beneath the consumption threshold.*

One option would be to simply withdraw the DA status of customers who are too small to be eligible for Noncore service, and return these customers to utility bundled service.

2) *"Grandfather" existing Direct Access into the Noncore*

Another option would be to allow existing DA, sub-Noncore level customers to be "grandfathered" into the Core/Noncore structure. ESPs serving this DA load would still be required to demonstrate resource adequacy sufficient to match it, and the Commission would retain authority to enforce the conditions under which DA customers lose their status and return to bundled service.

Recommendations

The option of forcing smaller DA customers back to bundled service would impose a burden on the utility of incorporating those returning customers into its procurement portfolio in an orderly fashion. It is also likely to generate opposition from present DA customers, without providing much if any benefit to bundled service or to the state in general. This option is therefore not recommended.

The option of grandfathering existing DA load into Noncore status has the advantage of familiarity and would not represent a threat to existing DA customers who have worked to maintain their eligibility to receive competitive service. We therefore recommend this option.

6) Do Not Permit Aggregation Prior to Expiration of All DWR Contracts

An issue closely related to the size threshold is that of "aggregation." Aggregation allows customers to consolidate load from multiple locations to achieve the required size for Noncore status. For example, if the threshold for Noncore is defined as 500 kW as above, qualification for Noncore status would be possible if a customer had 10 different sites each with 50 kW of load (or 50 sites with 10 kW of load, or theoretically 500 sites at 1 kW each).

Options in Addressing Noncore Aggregation

1) *Allow aggregation of unrelated customers without restriction.*

This option effectively enables unlimited exit from Core utility service, and resembles in many respects Direct Access service as envisioned by AB 1890.

2) *Allow aggregation of customers under one corporate or organizational umbrella.*

This option limits the participation in Noncore aggregation programs to customers such as chains, franchises, or cooperatives.

3) *Prohibit Noncore aggregation.*

Individual customers below the peak load threshold would be excluded from Noncore status.

Recommendations

The ability to aggregate creates several major implementation problems. First, it creates a "slippery slope" for utility planning purposes as to the amount of "Core" load for which they are responsible. As previously mentioned, setting the size threshold at 20 kW could result in perhaps a majority of load being eligible for Noncore status, making it difficult for the utility to plan its procurement strategies and protect bundled ratepayers.

Aggregation should not be allowed in the early years of the Noncore program, unless available space is not claimed by large customers

Secondly, it disrupts the equity balance among otherwise equally situated customers. Some parties have advocated limiting aggregation solely to sites "owned" by the same firm or company. Imposing such a requirement complicates the administrative structure, requiring the Commission to define ownership (i.e. do affiliates or subsidiaries qualify, and does partial ownership of less than 100% allow for qualification). These burdens are similar to the problems the Commission currently faces in trying to enforce its rules on utility-affiliate dealings.

Allowing aggregation only among sites with the same owner also raises important societal issues of equity and economic efficiency. Limiting aggregation to a single owner, for example, would allow for a 7-11 convenience store to qualify for aggregation while an otherwise identical mom-and-pop store across the street would be precluded.

In order to direct the initial potential benefits of the Noncore option to large industrial customers, those most likely to leave California, we therefore recommend allowing no customer aggregation through 2013. As mentioned in the context of establishing size thresholds, however, should the initial Noncore opportunities not be fully subscribed, consideration should be given to allowing aggregation, up to the established MW limits for each year, in post-2006 IOU planning cycles.

7) Establish a Competitive Benchmark Price that Reflects the True Cost of Utility Service

We recommend above that Noncore status be optional, not mandatory, for eligible customers, and that all customers have the choice of staying with the utility provider. This has the effect of placing the utility in competition with the Noncore-serving ESP, and raises the fundamental issue of the terms on which that competition will take place. This is principally an issue of the price of service from the utility to potential Noncore customers, known variously as the "benchmark price" or "price to beat" in other markets.

Options in Establishing the Competitive Benchmark Price

1) *Set the benchmark price based on the short-term procurement typical of ESPs*

This approach would have the IOU mirror the procurement practices of the ESPs with which it is competing for Noncore customers, revealing the relative strengths of each entity in procurement of this type.

2) *Set the benchmark price based on the IOU's total procurement portfolio.*

This approach provides a benchmark price that reflects the cost of serving Noncore-eligible customers as part of the utility's bundled service.

Recommendations

On one hand it is important, if the competition between utility and ESP for Noncore customers is to be meaningful, that the utility's price to these customers accurately reflect the total cost to provide service. The full range of utility procurement costs should be incorporated into the price that is offered to the Noncore customer, with no elements subsumed into other components of utility ratemaking. Competition between utility and ESP for Noncore customers should be transparent and on a total-cost basis.

On the other hand, suggestions that utility prices to Noncore customers should be raised to encourage switching, made in other restructured markets, have the effect of assuming the problem competition is supposed to solve: electricity rates are unsustainably high for an important segment of California's economy. Making these rates still higher to encourage competition will bias the utility-ESP choice as surely as will the hiding of utility procurement costs outside the utility's Noncore offer price.

Noncore customers should see the true cost of service from the utility's total portfolio

A claimed benefit of the Core/Noncore structure is that it will allow Noncore customers to procure electricity at a fixed price for a short period of time, for instance 1-3 years, an option that is not currently available from the utility. Insofar as this is the product that will be transacted in the Noncore market, some have advocated that the utility should be forced to procure only from the same market the ESPs would use. The difference in prices for these short-term products would reveal the relative competitive advantages of the utility and the ESP.

While this proposal has the advantage of placing the two competitors on the same footing, it also denies the utility the strength of its organizational structure: the ability to procure generation over a range of timeframes, from a mix of contracts and utility-owned facilities. In principle this structure should convey advantages to the utility. It is not clear that these advantages should be denied to Noncore-eligible customers should they choose to remain with utility service.

Forcing the utility to compete for Noncore customers using only short-term procurement divorced from its total portfolio effectively turns the utility into an ESP. It may well be that actual ESPs perform the ESP role better than a regulated utility; this does not seem to be the proper test. If competition between ESP and utility is what is sought, as a means to test the proposition that ESP service will ultimately be cheaper, handicapping the utility by denying its organizational strengths will not arrive at an honest answer.

Moreover, to meet the Commission's resource adequacy requirements and stimulate the construction of new generation infrastructure, California should encourage its ESPs to engage in long-term procurement practices more akin to what the IOUs undertake. Encouraging the IOUs to instead undertake short-term procurement is likely to be counterproductive in the face of California's infrastructure needs.

Utilities and ESPs can be placed in competition for the full range of products that Noncore customers may desire, on terms that accurately reflect total costs of service, and the viability of each provider will be fairly assessed as a result. Biasing the competition in either direction – favoring the utility by hiding costs, or the ESP by limiting the utility's strengths – may ultimately lead to higher, not lower, costs to Noncore customers.

In sum, potential Noncore customers should be able to assess the benefits of Noncore service by comparing the Noncore rate to the actual cost of electricity from IOU service. This means two things: IOU rates for potential Noncore customers should not be artificially inflated to stimulate competition, and these rates should not allocate to other customer classes costs attributable to potential Noncore customers.

It is recommended that the Commission accomplish this efficient and fair allocation of costs via its "bottoms-up" approach to ratemaking.

8) Public Purpose Programs Should Remain Available To, and the Responsibility Of, All Electric Customers

California's Public Purpose Programs express important priorities for the state's energy system. The challenge in continuing to pursue these state priorities in a Core/Noncore structure must be met on three principal fronts:

- Ensuring that the IOU can continue to cost-effectively meet these goals on behalf of Core customers;
- Ensuring that ESPs serving Noncore customers meet these goals; and
- Ensuring an equitable distribution of the costs associated with pursuing these goals.

General Recommendation

Public Purpose Programs should be supported by Noncore customers via a nonbypassable portion of the Cost Responsibility Surcharge.

Energy Efficiency Programs in a Core/Noncore Structure

The Commission's electric efficiency program (Pub.Util.Code 381 et. seq.) allocates approximately $275 million annually for electric service within the IOU service territories, with the goal, as stipulated in the authorizing legislation and in the joint agency Energy Action Plan (EAP), of pursuing "all cost-effective energy efficiency investments." Efficiency is widely recognized as one of the best methods of meeting the state's energy needs, and occupies the lead position in the EAP's "loading order."

The threshold test of cost-effectiveness presents two challenges: estimating potential benefits before making an investment, and assessing efficiency returns afterwards. The ratepayer-funded program administered by the Commission is subject to oversight on both of these fronts, and in theory extends to the load served by ESPs in the IOU franchise territory.

Recommendations

Insofar as ESPs serving the Noncore would be under Commission oversight in regard to efficiency programs, the state's ability to monitor and achieve progress towards its efficiency goals may not be impaired. Further study will be needed to assess the extent to which the state's efficiency programs are reaching ESP load as effectively as they are the load of the IOUs.

As a condition of allowing a CNC structure to develop without sacrificing the state's efficiency goals, we recommend that the process of assessing efficiency investments in the current Direct Access and any future Noncore market be strengthened, and that the Commission ensure that measurement and evaluation methods in place for investments in this load be robust. The Commission could establish uniform goals for efficiency gains – such as the "all cost-effectiveness" test, an IOU ratepayer cost-effectiveness test, or some percentage improvement – along with a standardized efficiency audit to be applied to Core and Noncore load alike.

The Renewable Portfolio Standard (RPS) Program

California's RPS program establishes aggressive goals for the development of new renewable generation resources, directing each load-serving entity to achieve a 20% renewable portfolio mix by 2017. ESPs are expressly included in the enabling legislation, although the Commission must by statute initiate a proceeding to determine precisely how ESPs are to comply. The joint agency Energy Action Plan embraces these RPS goals on an even more accelerated timeframe, seeking a 20% portfolio by 2010.

Unlike in the efficiency case, therefore, ESPs serving Noncore customers will be responsible for achieving a quantitative target for renewable generation, and will likely be subject to the same incremental increases in their renewable portfolios as IOUs (e.g. at least 1% more per year until 20% is reached). Pursuant to Pub.Util.Code §399.12(b)(3)(C), ESPs "shall be subject to the same terms and conditions applicable to an electrical corporation" under the RPS. Rules established so far for IOUs under the RPS program will also apply to ESPs serving the Noncore.

Recommendations

Pursuant to legislative direction, RPS obligations should be imposed upon ESPs serving the Noncore, under the same terms and conditions faced by the IOUs. RPS rules must be established soon for existing ESPs serving Direct Access load, presently approximately 12% of state load, regardless of whether the state pursues a CNC split. Establishing rules that work for the present Direct Access load may allow for rules that work for expanding the DA program to include Noncore customers.

Community Choice Aggregation (CCA)

California's new CCA program presents many of the same challenges to the IOU model as the concept of a CNC structure does. Via a CCA, communities (defined as cities, counties and/or joint power authorities) may aggregate their demand for electricity on a geographic basis and procure generation sufficient to meet their needs, independently of the IOU. Customers in the CCA area will have the option of opting out and continuing to receive service from the IOU. CCAs must also meet the targets of the RPS program, and must be assessed a Cost Responsibility Surcharge that reflects a fair-share apportionment of obligations entered into on their behalf.

Implementation of the CCA program is still in its infancy, but in concept some implications for a CNC structure are already clear. If a CNC structure contains a Core Aggregation provision that broadly embraces small consumers, then Core Aggregation and CCA are functionally quite similar[32]. The ability of large consumers to leave the utility system without associating themselves with a CCA, as would be possible under a CNC structure, may lessen the appeal of CCAs for communities containing large electricity users.

Recommendations

The Commission should continue to implement the CCA program regardless of whether a CNC structure is established, and should apply uniform standards to CCAs and ESPs serving the Noncore market regarding the CRS, coordinating exit from utility service, and demonstration of resource adequacy.

Baseline Rate Restrictions

As part of the state's response to the electricity crisis the legislature directed the CPUC to adopt a residential rate structure that exempts consumption below 130% of a regionally adjusted baseline (AB1x, Statutes of

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[32] Aggregation outside of the Community Choice Aggregation framework is not recommended as part of the initial Core / Noncore structure, as discussed above.

2000; implemented in D.01-05-064) from rate increases. The legislation in question stipulates the following:

"In no case shall the commission increase the electricity charges in effect on the date that the act that adds this section becomes effective for residential customers for existing baseline quantities or usage by those customers of up to 130 percent of existing baseline quantities, until such time as the department has recovered the costs of power it has procured for the electrical corporation's retail end use customers as provided in this division." (Water Code Section 80110)

Recommendations

Any Core/Noncore structure should follow Legislative direction regarding prohibitions on cost shifting, and not increase the electrical rates of sub-130% baseline customers.

Demand Response Programs

The Commission's Demand Response Programs – including Time of Use rates (TOU), the interruptible program, and the pilot Real-Time Pricing program (RTP) – will continue and expand regardless of the adoption of a Core/Noncore market. It is important to consider, however, the extent to which a Core/Noncore structure would impact the scope and effectiveness of these utility-focused programs.

Conventional wisdom holds that it is larger customers who will take most advantage of demand response programs, and in so doing provide the most benefit to the electrical system in moderating demand in response to prices. These are the same customers that may be drawn to Noncore service, thus potentially outside of the purview of these programs at present. Net benefits of the state's extended efforts to implement demand response programs may therefore be diminished as a result of declining participation on the part of those customers most likely to participate effectively.

Recommendations

As with the other public purpose initiatives discussed in this section, the Commission should design demand response programs that are available to, and utilized by, Noncore as well as Core customers. To the extent these programs are funded by nonbypassable charges assessed to Noncore customers, the

Commission may be obligated to design demand response programs to ensure this availability.

9) Provide Pricing and Green Choice Options for Core Customers

In a Core/Noncore market some forms of choice may be available to all customers. While Core customers would continue to receive bundled service from the utility, these customers could be allowed to choose among a portfolio of pricing options, options that would reflect each customer's desire to be exposed to changes in the underlying market for electricity. Core customers could also be given options to purchase renewable generation in addition to, not instead of, participation in the RPS program.

Core pricing options

Building on California's existing Time of Use (TOU) rates and the Commission's Demand Response proceeding (R.02-06-001), Core service could include a set of options that better reflect the actual real-time price of electricity. Via time-differentiated tariffs or advanced metering, Core customers could be allowed to see and respond to changes in these prices as they occur, modifying consumption to better reflect their relative preferences for electrical service or cost savings.

For larger Core customers in particular, those who would be eligible for Noncore status and who are attracted to service options in the Noncore market, this ability to more actively manage electricity consumption could be attractive. While all Core customers could be made eligible to receive the service, the cost of installing the necessary metering technology and monitoring the dynamics of the underlying market may make this option unappealing to smaller customers.

Recommendations

Core customers should continue to have the option of participating in California's Time of Use and Demand Response programs.

The Commission should immediately consider a Green Choice program that does not require the reinstatement of Direct Access

Green power options

Green power options have proven to be relatively popular among residential consumers in markets where retail competition has been introduced in electricity. Depending on the manner in which green power can be procured, there has also been some success in inducing commercial and industrial customers to participate in these voluntary arrangements. The operative phrase is “relative” success, however, as residential participation rates average approximately 1%, with a top range of 3-6%.

Three potential green power options should be considered in the context of a possible CNC market structure. These options differ in the extent to which they involve the IOU and in terms of the Commission’s ability to implement them with or without legislative authorization.

1) *Green Portfolio Options through the IOU.*

In this approach, the utility offers its customers the option of paying a premium above its commodity service price for a specified amount of green power, either a percentage of the customer’s total consumption, or a fixed block of power, such as 100 kWh per month. Premiums depend on the technology used to provide the renewable power, typically averaging around 2.5 cents for wind power products, substantially higher for solar.

In this model there is no need to open the electricity market to competition; all transactions are managed through the utility’s relationships with bundled customers. Hence, the Commission would not require legislative authorization – in the form of reinstating Direct Access – to implement this option.

2) *Green Choice through an ESP.*

An alternative approach in restructured markets allows customers to purchase all of their power from a competitive supplier, who in turn pledges to source all or some of that power from renewable technologies. According to US Department of Energy’s National Renewable Energy Laboratory (NREL) these products are often provided as 100% renewable, but in fact their power content does not regularly meet this standard. The role of third-party verification is therefore important in these programs, and independent organizations have arisen to provide certification of green power content.

Implementing a new ESP-based green power program would entail a reinstatement of Direct Access, and would therefore require legislative authorization before the Commission could proceed.

3) *Green choice partnerships between ESPs and the utility*.

NREL reports that continuing problems in competitive markets have resulted in a hybrid approach to the provision of green choice:

"In most restructured markets, alternative marketers have found it difficult to persuade customers to switch suppliers and, with few exceptions, green power marketing has been slow to emerge. Because of these market problems, green power marketers have started to team with default suppliers to jointly offer green power options. Although these teaming arrangements are relatively new, there are early indications that they may prove to be an effective strategy for marketing green power in restructured states, particularly to residential customers."[33]

This approach appears to resemble the Oregon model, in which the default utility offers green power choices to consumers, overlain with a marketing function provided by an ESP. While the extent of these "teaming arrangements" is unclear, it appears that the utility remains the provider of electricity; hence no "switching" appears to take place, and thus the suspension of Direct Access may not be implicated.

At the same time, one of the principal barriers to the expansion of green choice programs that numerous studies have identified – the barriers to customer awareness – may be overcome by the coupling of an ESP's marketing abilities to the utility's obligation to serve.

Recommendations

We recommend the hybrid approach, combining utility and ESP service in the provision of green choice. The utility could continue to procure renewable power to meet its RPS targets, and work with the ESP to procure sufficient further power to meet its green choice obligations. Since both sets of obligations

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[33] "Green Power Marketing in the United States: A Status Report" Sixth Edition; Bird and Sweezey; NREL Technical Report NREL / TP-620-35119; October 2003.

are associated with the utility, there would a path to determining the extent of new resource development, which is often a challenge in green choice programs. As with the IOU-only approach, each customer's bill could be adjusted to reflect its particular exposure to nonrenewable generation costs, depending on the extent of the customer's green choice commitments.

While this option requires further study, it appears to have promise for California. It should be noted that implementing this approach would not require a CNC structure or a reinstatement of Direct Access.

It is important to emphasize that the requirements of the RPS program will remain in place for utility providers of Core service, meaning that renewable procurement will increase substantially on behalf of this customer base even without additional voluntary programs. Any voluntary renewable programs must be compatible with the RPS, and provisions should be made to evaluate these programs independently of RPS development.

The priority for a green choice program should be the development of new renewable generation to displace nonrenewable alternatives. Recent evidence suggests that careful oversight is required to ensure that this development takes place. A structure for green choice in the Core will best serve the state if a robust mechanism of oversight is included.

In conclusion, the Commission has the authority to establish a green choice option for utility customers, regardless of whether or not a Core/Noncore structure is pursued, if the utility remains the provider of electricity to the customers in question. If the Commission desires to create a system of green choice in which ESPs provide for all electrical needs independently of the utility, this would entail a re-opening of Direct Access and would require Legislative authorization. Utility-based green choice could be implemented immediately, and it is our recommendation that the Commission begin consideration of this option in addition to the RPS program.

CHAPTER 5
Conclusions and Recommendations

The Commission should encourage the Legislature to act soon to establish certainty in the retail electric market structure. If the Legislature acts to establish a Core/Noncore structure, the new structure should include the following features:

1) Ensure Resource Adequacy Requirements Are Met

2) Coordinate Noncore Exit with Expiration of IOU Contracts and the IOU Planning Process

3) Establish the IOU as Provider of Last Resort (POLR) with Two Categories of Service

4) Establish a Fair Cost Responsibility Surcharge of Noncore Customers

5) Make Noncore Status Optional and Initially Available Only to Customers 500 kW and Above; "Grandfather" Existing Direct Access into Noncore Status

6) Do Not Permit Aggregation Prior to Expiration of All DWR Contracts

7) Establish a Competitive Benchmark Price that Reflects the True Cost of Utility Service

8) Public Purpose Programs Should Remain Available To, and the Responsibility Of, All Electric Customers

9) Provide Pricing and Green Choice Options for Core Customers

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ATTACHMENT A
Deregulation in the Natural Gas Industry

The Commission initially adopted the Core/Noncore model for natural gas customers in 1986.

Natural Gas Infrastructure

Before we look at the history of gas regulation, we need to understand the natural gas infrastructure and its components.

Natural gas infrastructure components include pipeline transportation and storage. Natural gas is shipped long distances through high-pressure, large-diameter pipelines. Pipelines crossing state boundaries are referred to as *interstate pipel*ines. The major utility pipelines that receive gas from the interstate pipelines are called *intrastate pipelines*. The Federal Energy Regulatory Commission (FERC) regulates interstate pipelines and the Commission has jurisdiction over intrastate pipelines. In California, three major utility companies distribute gas: PG&E, SoCalGas, and San Diego Gas and Electric Company (SDG&E). These utilities also manage vast networks of very small diameter *distribution pipelines*.

Storage enables the gas utilities to optimize use of interstate and intrastate pipelines. By injecting gas into storage in the spring and fall, utilities draw on these reserves to meet the summer peak demand associated with power plant and air conditioning load, as well as the winter peak demand for residential space heating. Storage provides overall system flexibility to accommodate daily, weekly, and seasonal fluctuations in consumer demand. Storage is also used as a price-hedging tool, since natural gas prices are typically lower in the summer than in the winter.

FERC Deregulation of Natural Gas

Deregulation in the natural gas market started at the federal level. In response to supply shortfalls of natural gas in the early 1970s, the Congress adopted the 1978 Federal Natural Gas Policy Act and deregulated wellhead prices. As a result, natural gas production increased and a supply surplus developed in the early 1980s. Subsequently, FERC passed a series of initiatives and unbundled natural gas and its transportation to let the utilities take advantage of the availability of cheap natural gas in the spot market. These initiatives released utilities from high-priced, long-term contracts with the interstate pipelines and opened up the transportation services on the pipeline.

- 1984-Order 380: Eliminated the variable cost components of pipeline minimum bills. This order modified the utilities' contract obligations to pay for high-priced gas bundled with the interstate pipeline transportation service and enabled utilities to purchase lower-priced natural gas directly from wellhead suppliers.
- 1985-Order 436: required pipeline to provide open access. This order established a direct relationship between consumers and producers. Consumers could directly negotiate prices with producers and contract separately with the pipelines for transportation.
- 1987-Order 500: Modified Order 436 to address pipeline companies' take-or-pay issues.[34] This order created a mechanism for pipeline companies to recover from their customers the costs of modifying or terminating their long-term contracts with producers.
- 1992-Order 636: 'unbundled' pipeline services and provided shippers[35] with firm interstate pipeline capacity rights to market their capacity to others. This order is also known as the final restructuring rule.

PUC Deregulation of Natural Gas

In step with natural gas market reforms at the federal level, during the late 1980's and early 1990's the Commission issued a series of decisions to establish a new regulatory framework for the natural gas industry in California. In Decision (D.) 86-03-057, one of the first decisions in these series, the Commission recognized that the 1978 Natural Gas Policy Act has created a vigorously competitive natural gas market and concluded that there was a need for a new natural gas industry regulatory framework. In this decision, the Commission started the unbundling of the gas utilities' services by ordering utilities to provide short-term transportation for large customers. Thus, it ordered utilities

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[34] Take-or-pay: The clause in a gas supply contract which provides for a specific period a specific minimum quantity of gas must be paid for whether or not delivery is accepted by the purchaser. Some contracts contain a time period in which the buyer may take later delivery of the gas without penalty.

[35] Customers who transport their own natural gas on a pipeline.

to file tariffs to provide short-term transportation. In establishing this new regulatory framework, one of the main goals of the Commission was to protect those customers who had no choice except receiving bundled services from the utilities while providing an opportunity for larger customers to benefit from the competitive natural gas sales market.

To accomplish its goal, in D. 86-03-057, the Commission established two classes of customers, Core (gas usage of less than 25,000[36] MCf per year) and Noncore (gas usage of more than 25,000 Mcf per year)[37]. It defined "Core" and "Noncore" customers as a direct function of which customers were deemed qualified for transportation service by the Commission. It concluded that because of the availability of transportation service and fuel switching for Noncore customers, utilities no longer should be obligated to seek long-term gas supply for those customers unless they were willing to sign long-term service contracts for gas with the utility.

However, the utilities were still obligated to provide interruptible gas transportation service to all customers similar to a Provider of Last Resort (POLR) function, at a lower quality of service. The utility plant remained dedicated to the public. In D. 86-03-057, the Commission also ordered utilities and other parties to file proposals for establishing rules and regulations and for its new regulatory framework.

On December 3, 1986, the Commission issued D.86-12-010 adopting rules establishing the general regulatory and industry structures. The Commission also adopted D.86-12-009 addressing the allocation of costs and rate design of gas transmission and procurement in light of policies adopted in D.86-12-010.

The Commission contended that due to the actions taken at the federal level the natural gas market was more competitive and a flexible and market-responsive rate design was needed. It defined the term "market responsive" as the unbundling of the traditional combination service provided by the

[36] 25,000 Mcf per year size limit was established in D.85-12-102 for transportation customers.

[37] Core customers are residential and small commercial customers who typically receive full service (procurement, transmission, storage, distribution, metering, and billing) from the regulated utility. Noncore customers are large commercial, industrial, and electric generation customers who may buy their own natural gas and pay for interstate pipeline transportation service, or purchase natural gas directly from the marketer at the California border.

distribution utility and a de-averaging of rates. Therefore, it separated the gas procurement and transportation functions of the utility arguing that the gas procurement function was clearly competitive in nature, and the transmission function had natural monopoly characteristics with economies of scale.

The Commission also established ‘elected Core’ customer class for those Noncore customers that wanted the utility to provide them with Core procurement service. It also asserted that in a competitive gas supply market buyers face the risk of gas price volatility. The Commission also concluded that Noncore customers who do not sign procurement contracts should not be protected from market swings.

In addition, in D.86-12-009, the Commission expressed its theoretical preference for a marginal cost methodology to achieve the goals of economic efficiency and equity. However, it argued that adequate marginal cost studies were not yet developed enough to be a basis for its rate design and adopted historical embedded costs on an interim basis.

Finally, after six years of debate, the Commission adopted the long-run marginal cost methodology for pricing California gas utilities services in D.92-12-058. It argued that the LRMC method captures the cost of new facilities as well as the short-term marginal cost of daily operating requirements. The Commission adopted the following marginal demand measures for computing and allocating marginal cost revenues:

1. Backbone Transmission: Cold Year winter Season for PG&E and Cold year for SoCalGas
2. Local Transmission: Cold Year Coincident Peak Month for PG&E and SDG&E
3. Storage: Cold Year Winter Season for PG&E, SoCalGas, and SDG&E
4. Distribution: Cold Year Peak Day for PG&E, SoCalGas, and SDG&E

The Commission ordered that resource planning should be updated in general rate cases and LRMC should be updated in each utility’s cost allocation proceedings.[38]

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[38]Under the natural gas new regulatory framework the gas utilities were required to file initially annual later biennial cost allocation applications (BCAP) to adjust gas utility rates to reflect annual changes in cost. In the cost allocation proceedings, the Commission mainly reviews any changes in authorized revenue requirement not previously reflected in rates; the amortization of

Footnote continued on next page

After more than a decade of using LRMC methodology for pricing California gas utilities services, the appropriate cost methodology for natural gas customers is still a controversial issue and a subject of debate. In its recent BCAP filing, SoCalGas and SDG&E have proposed to use embedded cost principles for natural gas cost allocation studies instead of LRMC. They argue that the use of embedded cost will minimize time and resources needed to review the derivation of customer-related costs, replacement cost adders, and the utility's long-term resource plans. Therefore, the applicants propose that it is more appropriate and beneficial to return to the use of embedded cost allocation principles.

Finally, in 1993, the Commission issued D.93-02-013 and unbundled the storage piece of natural gas infrastructure. This decision adopted policies and rules for permanent natural gas storage programs. Consistent with Federal policies, previous unbundling of Noncore gas supply and transportation service, and legislative urgings[39], the Commission authorized the unbundling of Noncore storage service. A "let the market decide" policy was adopted for construction or expansion of the storage facilities. The Commission adopted market-based Noncore storage rates applicable to the incumbent utilities, including incremental rates for service derived from new or expanded facilities. The Commission asserted that utilities were not obliged to expand their facilities to provide Noncore customers in their territories service unless customers guaranteed recovery of costs. It also allowed the independent storage providers to enter the storage market and compete with the incumbent gas utilities, subject to legal requirements.

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balances in authorized balancing and tracking accounts; forecast changes in the cost of gas supplies reflected in core customer rates; forecast throughput to customers; and changes necessary to fairly allocate costs among the various customer classes for the BCAP Test period.

[39] In late 1992, the legislature passed and the Governor approved Assembly Bill (AB) 2744 dealing with gas storage in California. AB 2744 argued that storage provides benefits to the natural gas infrastructure and urged the Commission to unbundle storage service and to encourage independent storage by establishing interconnection rules and reasonable cost allocations. This decision was also a response to the main concerns of AB 2744.

Cost Allocation Methodology: An Example of the BCAP

A BCAP is a rate design proceeding whose main purpose is to allocate the utility's revenue requirement, adopted in the general rate case (GRC) and other Commission proceedings, to different classes of customers based on a forecast of gas demand. In addition, BCAP examines the level of risk to cover the revenue requirement. [40] As an example, in D.00-04-060, based on a joint recommendation sponsored by the utilities (SoCalGas and SDG&E), the Office of Ratepayers Advocates (ORA), and other parties, the Commission adopted the following rate designs for SoCalGas and SDG&E.

- SoCalGas' rates were reduced by $158.9 million for Core and $50.7 million for the Noncore, based on a throughput of 950.3 MMdth. The Commission also adopted 75/25 (ratepayer/shareholder) balancing account protection for Noncore throughput, and 50/50 balancing account protection for storage. In addition, it adopted a transmission resource investment plan of $32.5 million; that level of investment was needed for the next investment years to satisfy anticipated growth in demand.
- SDG&E' rates were reduced by $18 million for Core and $18.7 million for the Noncore, based on a throughput of 480 million terms for former Utility Electric Generator (UEG) customers. In addition, it adopted a transmission resource plan of $31 million; that level of investment was needed for the next investment years to satisfy anticipated growth in demand.

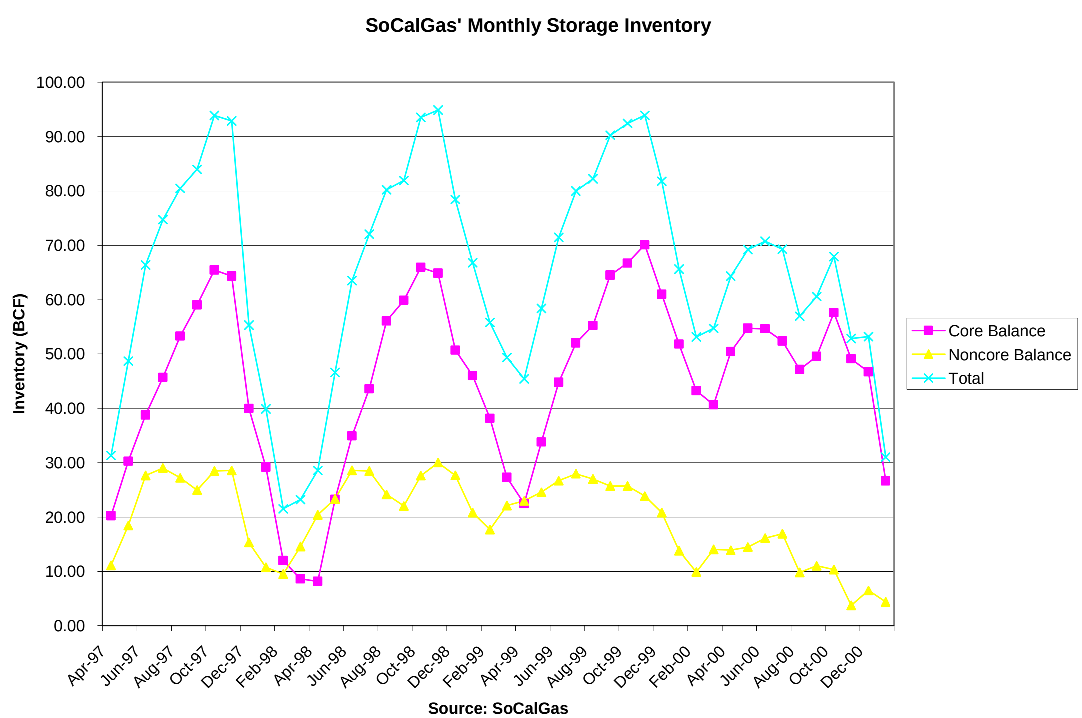
Noncore Storage Activities Wrong in 2000-2001 Energy Crisis

As explained above, storage is an optional service for Noncore customers. It is offered by the two major natural gas utilities, PG&E and SoCalGas and the independent storage providers, Wild Goose and Lodi. Utilities are not responsible for ensuring that Noncore customers have reserved adequate storage capacity to meet their natural gas requirements. However, utilities are required

[40] It does not include the cost of gas.

to reserve storage capacity for their Core customers; PG&E and SoCalGas'[41] Core reservation are about 32 Bcf and about 70 Bcf respectively.

In the 2000 injection season, Noncore customers did not inject as much gas into storage as they could have, particularly on the SoCalGas system, as shown in the figure below. While SoCalGas' unbundled storage program was fully subscribed, gas prices increased in May of 2000, the injection season, at the same time the forward price strip indicated lower prices in future. Therefore, the Noncore customers decided not to inject into storage. Later in the year, as electric generation demand rose, these customers increased natural gas deliveries to California in order to meet their increased gas demand, causing usage of the utility backbone natural gas transmission systems to significantly increase.



[41] PG&E's total storage capacity is about 98 Bcf. SoCalGas' total storage capacity is currently about 122 Bcf after its 2002 expansions.

Nonetheless, the storage reserves PG&E and SoCalGas maintained for Core service provided overall system reliability, and enabled them to meet all customer classes' demand in 2000 and 2001.

In response to concerns that Noncore customers were not injecting adequate supplies of natural gas into storage, the Commission initiated a proceeding, Order Instituting Rulemaking (OIR) 01-03-023, to consider whether it should revise storage rules for Noncore customers. One of the central questions of R.01-03-023 was whether the Commission should change curtailment and diversion priorities for Noncore natural gas customers.

In D.01-12-019, the Commission concluded that it should not modify the gas tariffs for SoCalGas and PG&E to grant gas service priorities to electric generators. It also concluded that the Commission should not modify gas storage rules at that time. In addition, D.01-12-019 ordered parties to file opening comments on the question of whether and how the Commission should allocate gas among electric generators during times of curtailments. Finally, the Commission issued D.02-07-029 where it examined and rejected the question of granting a new gas priority to electric generators for natural gas service based on a plant's heat rate.

Noncore Migration to Core Issues

During the 2000-2001 winter, natural gas spot prices increased tremendously. Many Noncore customers in SoCalGas and PG&E service territories wanted to return to bundled Core service to take advantage of the lower cost of gas procured by utilities for its bundled customers.

In December 2000, SoCalGas filed Advice letters[42] and argued that if Noncore customers were permitted to elect Core subscription service, SoCalGas would be required to purchase additional volumes at the California-Arizona border, which would significantly increase SoCalGas' cost of gas for its existing Core and Core subscription customers. SoCalGas proposed a different rate mechanism for those Core subscription customers that elected Core subscription on January 1, 2001. The Commission denied SoCalGas' proposal and suspended

[42] SoCalGas Advice Letters 2987 and 2979.

transfers of customers to Core subscription service and ordered SoCalGas to file an application to address these issues.[43]

In July 2001, PG&E filed an Advice Letter with the Commission[44] and made similar arguments and made specific proposals to mitigate the situation. The Commission denied PG&E's proposal and suspended transfers of customers, the voluntary transfer of Noncore customers to Core service, and asked PG&E to file an application to address these issues.[45]

Subsequently, the Commission modified the rules to allow Noncore customers to migrate to Core service for SoCalGas, SDG&E, and PG&E, concluding that a five-year customer commitment to utility procurement service is adequate to prevent undue customer switching and to facilitate utility asset planning. [46]

Natural Gas Infrastructure Expansions Serving in California

In 1990, responding to a shortage of interstate pipeline capacity to California, the Commission issued Decision (D.) 90-02-016 and adopted a "let the market decide" policy with regard to proposals for new interstate pipeline capacity. In D.90-02-016, the Commission noted, "California has experienced four curtailments of Noncore gas service within the last three years, including three of the four winters since open access transportation first became available to California."[47]

As a result, numerous pipeline companies proposed expansions of interstate capacity to California. The Commission took the position at the FERC that shippers who wanted additional pipeline capacity to be built to the state had to be willing to pay for that capacity. At the same time, the Commission did not require California's existing utility customers to pay for any of the proposed

[43] Resolution G-3304.

[44] PG&E AL 2326-G.

[45] Resolution G-3318.

[46] D.02-08-065 for SoCalGas and SDG&E; D.03-12-008 for PG&E.

[47] D.90-02-016, Pg. 114.

expansions in their utility bills. Ultimately, several pipelines expanded their capacity or built new pipelines to California. Within California, the utilities expanded their systems to take delivery of the new gas supplies.

In 1993, as discussed above, the Commission "unbundled" Noncore storage services and also adopted a "let the market decide" policy with regard to the construction or expansion of intrastate storage facilities.

This "let the market decide" policy has led to sufficient interstate pipeline and storage expansions serving the California natural gas market. During 2001-2003 period, about 2,000 MMcfd of additional interstate pipeline capacity and about 38 Bcf of additional storage capacity came on line, based on the large Noncore customers' long-term commitments. In addition, SoCalGas increased its transmission capacity by 375 MMcfd (11% increase) in 2001 and 2002 and PG&E increased its transmission capacity by 180 MMcfd.[48]

Upcoming OIR on Gas Industry Infrastructure

On January 27, 2004, in response to ongoing changes in the natural gas market the Commission issued an Order Instituting Rulemaking (OIR), R.04-01-025[49]. In R.04-01-025, the Commission states:

> "This Order Instituting Rulemaking (OIR) is issued in response to new reports, recent Federal Energy Regulatory Commission (FERC) orders, and ongoing changes in the natural gas market, which indicate that in the long-term there may not be sufficient natural gas supplies and/or infrastructure to meet the requirements of all California residential and business consumers unless the Commission takes certain actions in the near future. "

[48] During this time period, the utilities made extensive additions to distribution system capacity as well.

[49] In November 2001, in response to SBX1 6, the Commission issued *California Natural Gas Infrastructure Outlook, 2002-2006* report. In its report, the Commission evaluated California's natural gas transportation and storage system, and concluded that the California natural gas infrastructure is adequate to provide seasonally reliable amounts of competitively priced natural gas to residential, commercial, industrial, and electric generation customers for the 2002-2006 period. The report also promised that the Commission would conduct another overall evaluation of California's natural gas infrastructure in two years. This rulemaking also serves as that evaluation.

In R.04-01-025, the Commission asserts that to ensure reliable, long-term natural gas supplies to California at reasonable rates, it must make certain decisions in 2004 regarding following issues:

1. Increased demand reduction efforts (e.g., energy efficiency and renewable energy programs[50]

2. The availability of sufficient firm interstate and intrastate pipeline capacity for serving California

3. The benefits and flexibility of storage facilities fully appreciated and utilized;

4. Access to imported natural gas supplies (e.g., from LNG facilities) to meet the new challenges

To meet some of the deadlines facing the utilities and other natural gas market participants,[51] the Commission establishes two phases in this rulemaking. Phase I of this proceeding will address the following issues:

1. Sufficient Interstate Pipeline Capacity to Meet Core Procurement Supply Obligations

The Commission orders each utility to propose the aggregate amount of firm rights on interstate pipelines, which needs to hold in 2006 under long-term contract and he aggregate amount of out-of-state supply, which it believes it will need in 2016 in order to serve its Core procurement supply.

2. Access on Intrastate Pipelines to LNG Supply

The Commission orders utilities to propose guidelines concerning on how natural gas supplies from potential LNG facilities constructed on the West Coast could access each of their intrastate pipelines and distribution facilities.

3. Access on Interconnecting Facilities with Interstate Pipelines

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[50] The Commission is addressing this issue in R01-08-028.

[51] Some of the interstate pipeline capacity contracts are expiring in the next two years; pipelines related to potential LNG projects; and interstate pipeline expansions.

The Commission directs SoCalGas to file a proposal for providing additional access for Rocky Mountain supplies to reach California through SoCalGas' interconnecting facilities.

The Commission is planning to issue a decision on phase I issues by the Summer of 2004.

The Commission also argues that during the 2000-2001 energy crisis Californians had to pay billions of dollars of additional costs in natural gas and electric prices. The Commission points out that this happened during abundance of natural gas supplies and we are currently facing a tight natural gas supply market and we may face insufficient supply in future. Therefore, R.04-01-025 concludes that it's essential for the Commission to take new steps and adopt policies and rules to prevent natural gas shortage and protect Californians in the event of an emergency. Therefore, the Phase II of this rulemaking addresses these concerns:

1. Natural Gas Utilities' System Reserves for Emergencies

The Commission proposes that public service obligations of California natural gas public utilities, in their role as system operators, be expanded to include a requirement for maintaining "emergency reserves," which consist of: (1) slack capacity on the intrastate pipelines for maximum flexibility of access to storage and interconnecting pipeline facilities; (2) an emergency supply of natural gas in storage in California; and (3) a limited amount of additional interstate pipeline capacity subscribed to by the California utilities solely for the emergency needs of the utilities.

2. The Utilities' Potential Backstop Function

The commission is currently considering the necessity of the natural gas utilities operating as a backstop *if* the Noncore market participants do not ensure sufficient interstate pipeline capacity to meet the Noncore customers' needs in the future, a function totally separate from the emergency reserve requirement.

3. New Ratemaking Policies Consistent with the Goal of Ensuring Adequate and Reliable Long-Term Natural Gas Supplies

In light of all changes in the natural gas market, the Commission is reexamining its ratemaking policies, to potentially modify its current policies. It requires the utilities in their Phase II filings to identify and propose changes to current "at risk" conditions they face in their rates, which they believe create incentives that conflict with the Commission's policies in favor of energy demand reduction efforts (e.g., energy efficiency programs) and the Commission's proposals for additional slack capacity, additional interstate pipeline reservation charges and emergency reserves of natural gas.

This rulemaking is one of the most comprehensive reviews of the natural gas market since the late '80s when the deregulation of natural gas industry started in California.

Conclusion

The deregulated natural gas market has been perceived as an example of a robust competitive market for many years. Some energy experts, drawing a parallel between natural gas and electricity markets, argue that 'It worked for natural gas hence it works for electricity.' Thus, they advocate moving to a similar Core/Noncore model for the electricity market.

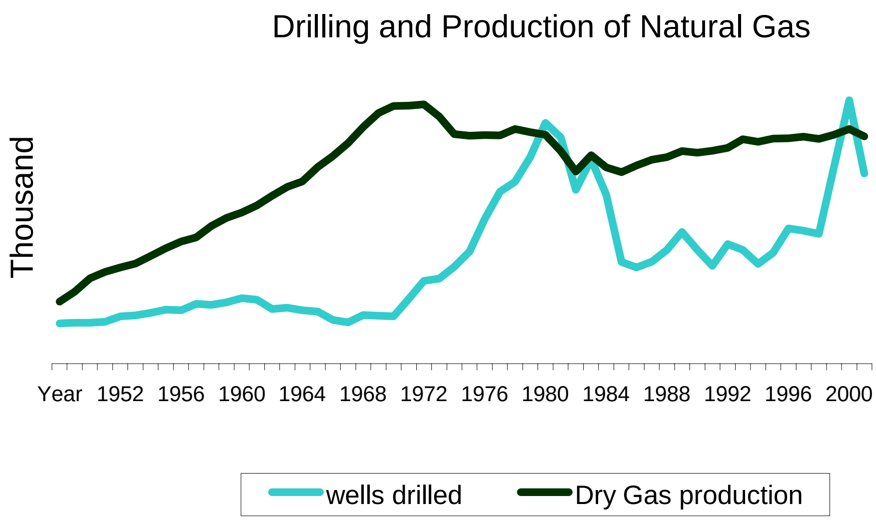
First we need to compare the natural gas infrastructure and its components to electricity.

Infrastructure Differences

As explained above, storage is an important component of natural gas infrastructure for providing overall system flexibility and pricing mitigation measures. Storage feasibility is one of the major differences between gas and electricity infrastructure. We cannot store electricity as we can store natural gas to optimize the system reliability or as a price hedging tool.

Another major difference is the capital outlay necessary for new infrastructure. The cost of drilling a new well is only few million dollars on average compared to hundreds of millions of dollars to cite and construct a new power plant[52]. In addition, citing and drilling a gas well has a much quicker turn over than citing and building a new power plant. Therefore, in general, the price of natural gas has had a direct relationship with the number of active rigs and drilling activity. Whenever the price of natural gas decreased the drilling activity declined and the scarcity of the commodity contributed to higher prices and as a result more drilling activity and lower prices with a lag of only few months.

[52] $110 per foot is the average drilling cost for a new well. For example: According to EIA' s Annual Energy Review 2002, the average depth of natural gas well was about 6,000 feet and the drilling cost would be $660,000.



In addition, the natural gas market is a national and to a lesser degree an international market[53] which provides a more dynamic situation for competition. On the other hand, the electricity market is based on a local/regional market that creates limited options for competition. For example, even in a situation of a natural gas shortage in North America, importing LNG could be a viable option whereas electricity cannot be imported from overseas in case of a serious shortage.

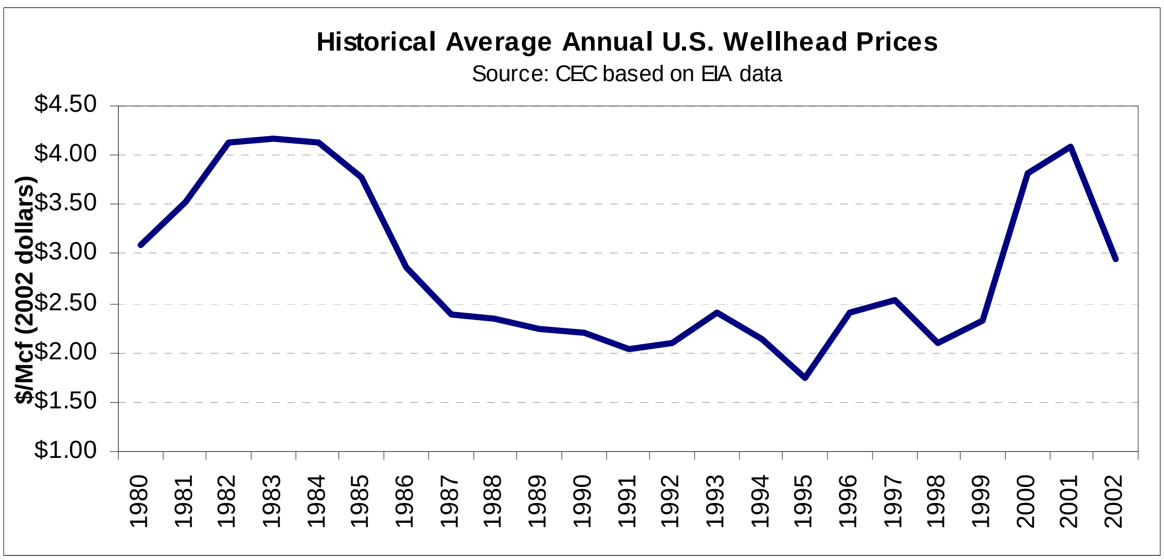
Other Differences and Issues

As a result of the 1978 Federal Natural Gas Policy Act, natural gas production increased and by the late '80s the price of natural gas decreased from $4.00 Mcf to about $2.00 Mcf. Therefore, by mid '80s when the Commission started its new regulatory framework the natural gas prices had a decreasing trend and there was a surplus of natural gas in the market. The Commission's goal was to ensure that the natural gas utilities and their customers would be able to take advantage of this situation and for many years the natural gas customers in California enjoyed low natural gas prices.

[53] Gas imports from Canada and LNG.

Another important element that helped natural gas market to establish this market surplus was the availability of fuel switching in the early years of the natural gas deregulation. As a result of fuel switching availability, natural gas producers had to compete with alternate fuels, e.g. oil. Because of legitimate environmental concerns, in the early '90s when a competitive natural gas market had already been established the Commission eliminated fuel switching capability.

Presently, there are serious concerns among natural gas experts regarding the declining production rate compared to drilling activity. Many natural gas experts argue that as a result of the scarcity of resources and higher production costs, it may be that the era of $2.00 Mcf natural gas is over.[54] The Commission's recent rulemaking is a response to this situation.



[54] Many participants in the CPUC / CEC December 2003 workshop expressed this view.