Energy Research and Development Division
FINAL PROJECT REPORT

A DAILY SIMULATION MODEL OF THE CALIFORNIA NATURAL GAS TRANSPORTATION AND STORAGE NETWORK

Prepared for: California Energy Commission
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PREFACE

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A Daily Simulation Model of the California Natural Gas Transportation and Storage Network is the final report for the Developing a Low Cost, Daily Simulation Model Of The California Natural Gas Transportation And Storage Network project (Contract Number 500-02-004, Work Authorization Number MRA-59) conducted by the University of California, Davis. The information from this project contributes to Energy Systems Integration-Strategic Natural Gas Program.

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ABSTRACT

This project analyzed nonlinear programming techniques in a simulation model of distribution and storage logistics in the California natural gas network. The analysis emphasized seasonal and weekly natural gas supply and demand balanced with a combination of transportation, injections or withdrawals from underground storage, and short-term linepacking in pipelines. Linepacking is natural gas occupying all pressurized sections of the pipeline network. The model recommended procuring natural gas seasonally and weekly to reduce costs. The model represented decisions by utilities, customers, pipelines, and storage operators in the northern and southern systems that bring California prices towards equilibrium where location (spatial) and time (intertemporal) arbitrage opportunities have been exhausted. The model was calibrated to consumption and production data from recent years and encompassed 52 weekdays/weekend pairs. The model focused on the two main regions within California and also accounted for the links with other parts of the North American network.

The model successfully analyzed the effects of major changes in regulatory rules or infrastructure such as requirements that distribution companies hold a specified amount of natural gas in storage on behalf of "core" customers or which rule constrains their procurement pattern (such as the price of liquefied natural gas from Northeast Asia, or the substitution of natural gas for coal in electricity generation in Ontario). The model emphasized seasonality within the network and across customer types.

Keywords: Simulation, mathematical programming, storage, arbitrage, seasonality, natural gas.

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EXECUTIVE SUMMARY

Introduction

Natural gas demand is characterized by seasonal cycles for residential heating and air conditioning; and cycles between weekdays and weekends with a mix of industrial and residential uses. This demand variability, or unevenness, has increased significantly in the last few years because peaking power plants are consuming more natural gas to generate electricity. Renewable resources, such as solar and wind, also add uncertainty to the demand for natural gas since their production rates are uneven and seasonal.

Storing natural gas close to the consumption centers becomes valuable given this fluctuating demand and mostly steady production rates and fixed-capacity pipelines. Stocks can be kept either in underground storage reservoirs or packed in the pipelines. Underground storage serves primarily to smooth the seasonal cycle, and linepacking serves the weekly cycle. Linepacking refers to natural gas occupying all pressurized sections of the pipeline network. These two types of storage do not necessarily interact. Moreover, underground storage is being used by many market participants in a more speculative manner to take advantage of short-lived profit opportunities signaled by spot and futures prices, which have strong seasonal and weekly patterns. The mixture of operational and financial motivations behind storage decisions results in complex patterns, and deserve analysis by researchers, policymakers, and regulators.

Project Purpose

This project provided the best profiles of natural gas flow, underground storage, and linepacking decisions under various scenarios. These scenarios used a mathematical programming model calibrated to the observed patterns in California's natural gas demand, supply, transportation, and storage for 2006-2007.

Project Results

The model provided insight into the interactions among the demand cycles of various customer types in California and in other market centers (specifically Illinois) that compete with California for the same natural gas resources. Those interactions must be understood if decisions about when and from where to buy gas are to be cost efficient for California. Winters are colder than summers in California however the seasonality is even more pronounced in Illinois, although Illinois's weekly cycle in industrial demand is less pronounced. The model determined appropriate flows to California and Illinois from the common producing region of Western Canada, given the relative seasonal and weekly cycles. The model represented California's place within the North American network with similar seasonal and weekly cycles for other producing regions relevant to California.

Large North American natural gas network forecasting models are often used by energy agencies and highly detailed engineering models are used for pipelines to manage their operations. This simulation model was designed specifically for California and represented by two consumption regions and five supply regions, divided into fifty-two pairs of weekdays and weekends. The level of location (spatial) and time (temporal) disaggregation chosen ensured that the model's output was detailed enough to capture the effects of, for instance, an operational flow order issued by one of the natural gas utilities over a summer weekend. Short-lived events, like an operational flow order, are caused by capacity constraints in pipelines or compressors. They affect prices and trigger decision changes throughout the California network. The model was a valuable analytical tool for understanding how the various activities or market hubs in California are interconnected to the larger network.

The model was also effective for considering major changes in policies or circumstances. One such scenario considered was removing the requirement that distribution utilities must hold a specified amount of natural gas in storage by November 1 of each year for their "core" customers. The model suggested that this requirement was unnecessary since distribution companies would find the normal intertemporal price signals ample incentive for storage. A second scenario considered the impact of a possible liquefied natural gas (LNG) terminal in Baja California, Mexico. The model suggested that this new LNG terminal will encourage further California underground storage. California will import LNG from the Pacific basin and since this area's seasonality is more pronounced than in California the difference will encourage underground storage in the state. The third scenario offered a related insight. Using more natural gas for electricity generation in Ontario, Canada will divert these supplies from the producing regions of Alberta, Canada that would have gone to California during the summer, when California has lower heating demand and traditionally fills its underground storage. This diversion may be less obvious on weekends, reducing the affect on California's weekly cycles, and less pronounced than implied by a simple annual network model.

Project Benefits

The model provided valuable insight into demand and market scenarios for California's natural gas use. This information will facilitate decisions about when and where to buy natural gas most cost-effectively and helps ensure a steady natural gas supply for California ratepayers.

CHAPTER 1: Introduction

This project analyzed nonlinear programming techniques in a simulation model of distribution and storage logistics in the California natural gas network. The analysis emphasizes daily data, not only seasonal demand cycle because a weekly demand cycle influences natural gas flow and storage decisions. The model represents flows from natural gas supply nodes (the producing areas serving California) to demand nodes (Pacific Gas and Electric Company [PG&E] and Southern California Gas Company [SoCal Gas] service areas) that move natural gas along fixed capacity arcs and can be temporarily stored at intermediate nodes (underground storage facilities and pipelines) along the way. The costs of gas from different producing regions at different times of the year and week and the cost of storing gas are the driving forces shaping the optimal daily profile of flows and inventories,.

Data examined to develop the seasonal model revealed noticeable weekly cycles in the demand and logistics of the California natural gas markets. It is important that distinguishing between weekends and weekdays in each month allows for the complementary nature between underground storage and linepack management. Second, monthly averages often disguise shorter-lived pipeline or storage capacity constraints.

The scenarios focused on California's northern and southern regions however the model accounts for the links with other parts of the North American network. Included are direct links with producing regions where California obtains its gas (Western Canada, Rocky Mountains, San Juan basin, Permian basin) and indirect links with other demand regions that compete for the same sources of gas. The seasonality and day-of-week effects in these demand regions have different profiles than observed in California, as seen in their patterns of flows and in forward price curves. Those different demand profiles transmit themselves into seasonal and weekly storage within California.

The model's planning horizon is one year starting in April, the official start of the storage injection season. Overall, the model intends disaggregated by location and time to analyze the effects of increased variability in prices and demand requirements that have been observed in the California natural gas market during the last few years. This report includes sensitivity analysis using spatial and temporal aggregation. Six regions in California and each day of the week were separately studied. The model treated California as a single location and the year as two periods with steady daily natural gas injection from April through October and steady daily withdrawal from November through March.

Variability is distinct from uncertainty. Conditions may make for an unusually cold day in January, with Californians using more natural gas than anticipated, however it is expected for weather conditions to be colder in January than May requiring more natural gas for heating. These are variable factors, not uncertainty. Weekends also cause variability, not uncertainty.

Storage is often described as a buffering mechanism, suggesting its principal role is to accommodate uncertainty. Storage, however, accommodates variability too, even more than uncertainty. For natural gas planning, accommodating uncertainty is considered against the backdrop of the known variability. For instance, an unusually warm day in early November is more easily accommodated than an unusually cold day in late March because the seasonal variability expects large natural gas stocks in November and small stocks in March. The model considers storage as a response to the known variability in California as it interacts with the variability elsewhere in the North American network. A full model of uncertainty must also include variability.

1.1 Seasonal Cycles in Natural Gas Consumption and Flows

Seasonality in the natural gas demand profile is well understood and accounted for in most models, although sometimes only at the level of two periods per year, injection and withdrawal seasons. Such seasonality has been characterized by a large peak during the winter months coinciding with heating load by residential and commercial customers. In the last decade, however, with low-cost, low-polluting combined-cycle electricity generation plants opening in California, a secondary peak has emerged in the summer months. Combined-cycle electricity generation units are often the peaking units, providing peak load power for air conditioning in the hottest summer days. In addition, in California, natural gas requirements by the agricultural and food processing sector also peak in the summer, increasing natural gas demand. These differences in seasonality imply that the mix of customer types changes through the year. Residential heating demand is more seasonal for PG&E in Northern California (Figure 1) while seasonality from electricity generation is greater in Southern California (Figure 2).

Figure 1: Monthly PG&E Sendouts by Customer Type (April 2004-March 2005)

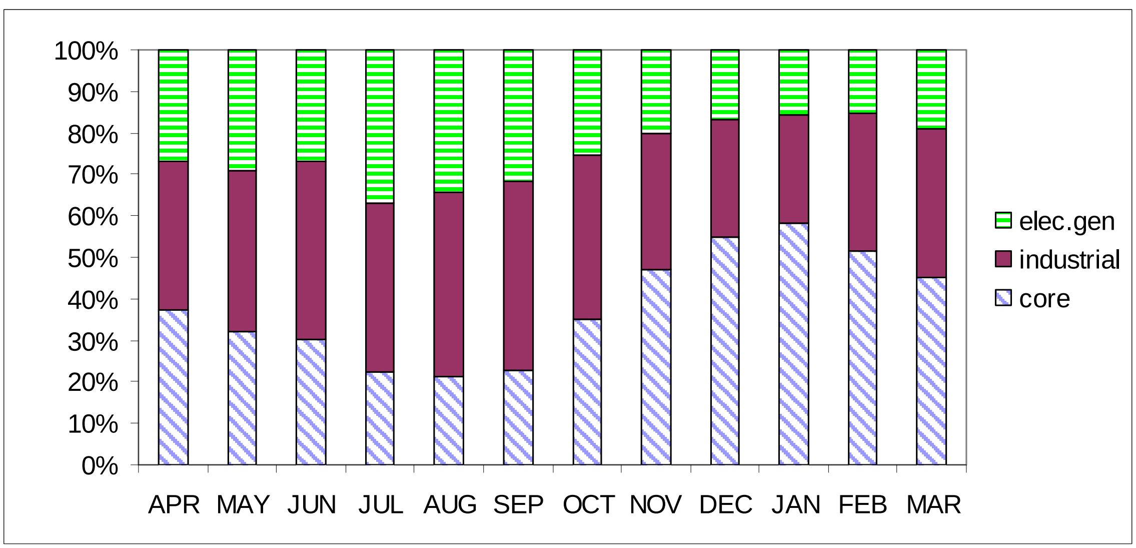
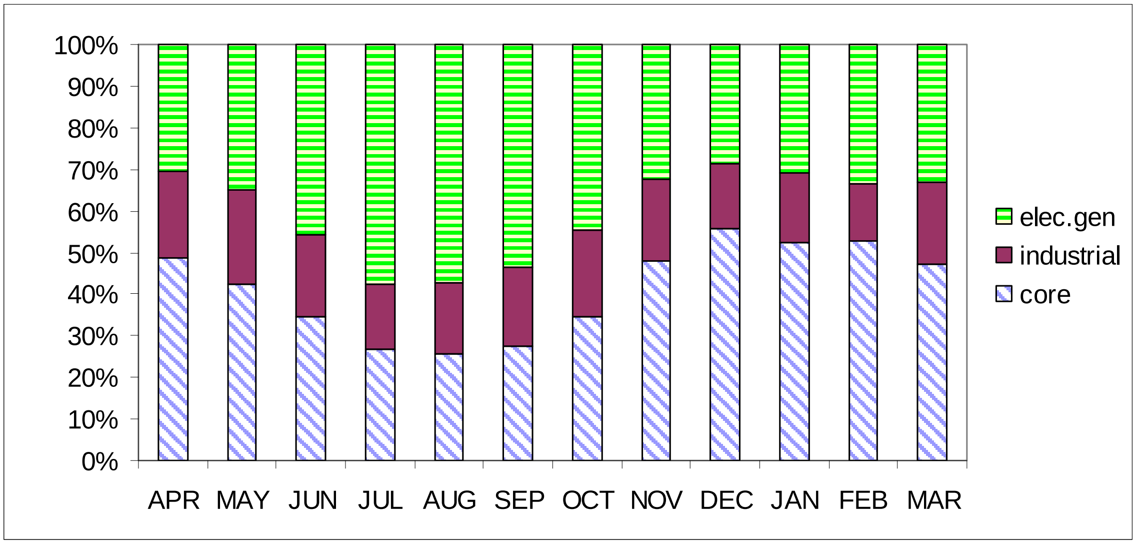
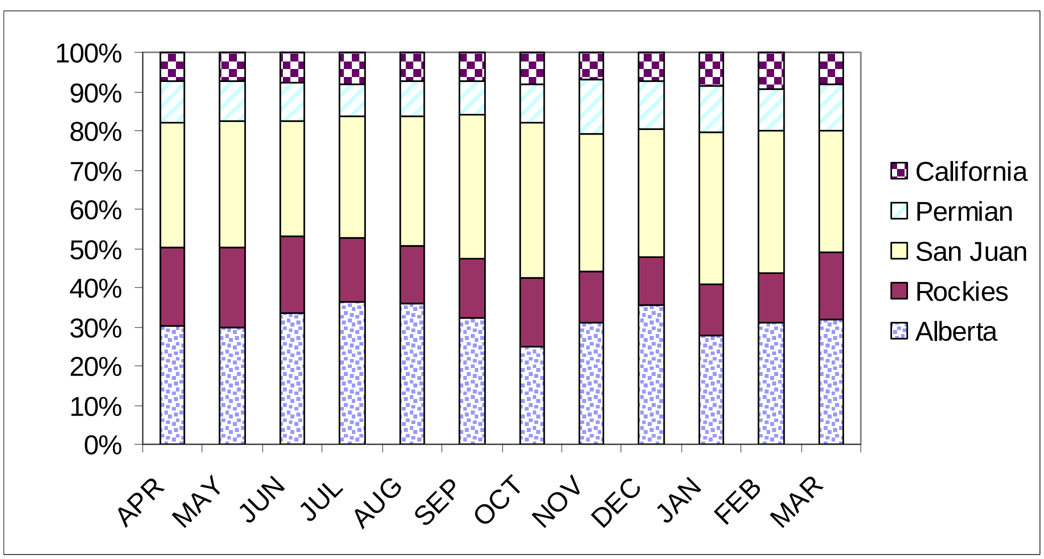


Figure 2: Monthly SoCal Gas Sendouts by Customer Type (April 2004-March 2005)



The supply mix also changes throughout the year. The relative prices of gas from the producing regions serving California vary seasonally. The relative strength of demand by competing regions of integrated North American natural gas network determines the most attractive and the marginal source of supply for California each season (Figure 3). Other recent years show slightly different mixes, but the existence of seasonality in the mix is clear.

Figure 3: Monthly California Import Shares by Producing Region (April 2004-March 2005)



The supply mix for California is not an unalterable pattern, however it does reflect, to some extent, the network responses to the unalterable seasonality in the weather. Similarly, the supply mix partly reflects California's own response to the unalterable seasonality, making underground storage in California strongly seasonal.

Is underground storage in California also an important factor and adequate? For example, SoCal Gas' typical consumption (send-out) is 2.5 billion cubic feet per day (Bcfd) while stocks accumulate through the "injection season" to at least 75 additional billion cubic feet (Bcf). Thirty days of average consumption rates is not a trivial amount of storage. The supply mix, demand mix, pipeline capacities, and pricing profile would look quite different if California had no underground storage.

1.2 Weekly Cycles in Natural Gas Consumption and Flows

The weekly cycle in natural gas demand has been investigated much less than the seasonal cycle. Economic activity slows during the weekends and holidays but this does not necessarily mean that total natural gas requirements also decrease at that time. The reason is that different customer types display different weekly cycles. The model estimated the relationships between the variables or regressions of daily sendouts by PG&E and SoCal Gas from April 2002 through March 2007 using an indicator variable that takes the value 1 for non-business days (Tables 1 and 2). These regressions demonstrate the importance of the non-business days and do not allow for all complexities in sendouts. The basic regressions revealed statistically significant demand cycles for all the customer types. The volume of natural gas required for industrial uses and electricity generation decreases during the weekend. The drop represents 12.2 percent and 3 percent of average business-day requirements for industrial customers in Northern and Southern California respectively.

The weekly cycle does not change seasonally in the PG&E system but it is more acute in the summer in the SoCal Gas system. For electricity generators, the weekend demand drop during the summer months –April through October– is barely one third of that on winter weekends. On the other hand, the winter sendouts to small residential and commercial customers are larger on non-business than on business days while summer sendouts are smaller on non-business than on business days. The winter increases represent 43 percent and 27 percent of the average business day requirements for that season in the PG&E and SoCal Gas service areas respectively. Because core customers account for the largest share of total consumption, the weekly cycle of total demand resembles the pattern of that group.

Table 1: Estimated Coefficients from Regressions of Daily PG&E Sendouts on Non-Business Day Indicator Variable

	Core	Industrial	Electricity Generation	Total
Coefficients	**816.88** (78.09)	**749.92** (246.51)	**543.46** (97.56)	**2110.27** (186.99)
Non-Business Days[1]	**356.97** (13.96)	**-92.07** (-12.38)	**-149.42** (-10.97)	**115.47** (4.18)
Non-Business Days * Injection Season[2]	**-651.96** (-20.89)	-10.38 (-1.14)	**72.46** (4.36)	**-589.88** (-17.52)
R-Squared	0.20	0.16	0.07	0.19

Note: t statistics in parentheses. Bolded coefficients are statistically significant at the 5% level.

Table 2: Estimated Coefficients from Regressions of Daily SoCal Gas Sendouts on Non-Business-Day Indicator Variable

	Core	Industrial	Electricity Generation	Total
Coefficients	**1085.97** (111.24)	**981.65** (462.40)	**646.79** (83.75)	**2714.42** (242.97)
Non-Business Days	**296.97** (12.29)	**-31.14** (-5.93)	**-261.74** (-13.69)	4.10 (0.15)
Non-Business Days * Injection Season	**-595.21** (-20.35)	**-112.63** (-17.71)	**199.62** (8.63)	**-508.22** (-15.18)
R-Squared	0.19	0.34	0.09	0.19

Note: t statistics in parentheses. Bolded coefficients are statistically significant at the 5% level.

[1] This indicator variable takes the value 1 on weekends and holidays and zero otherwise.

[2] This interaction indicator variable takes the value 1 on weekends during the official storage injection season.

Similar weekly cycles in demand for California characterize the consumption profiles observed in other upstream market centers throughout the North American network. With California located "at the end of the pipeline" and receiving 85 percent of its gas from out-of-state sources, upstream weekend swings in natural gas consumed could affect the amount of Canadian, Rockies and Southwest gas entering the state (Table 3). The dependent variables are daily flows coming into California from each producing region.

Table 3: Estimated Coefficients from Regressions of Daily Flows into California on Non-Business-Day Indicator Variable.

	Canada	Rockies	San Juan	Permian	Total
Coefficients	**1450.38** (155.96)	**691.47** (106.74)	**1615.64** (256.18)	**601.30** (120.54)	**4358.18** (335.36)
Non-Business Days	**-229.10** (-9.96)	**-85.38** (-5.33)	1.02 (0.06)	**87.56** (7.09)	**-225.89** (-7.02)
Non-Business Days* Injection Season	**339.17** (12.18)	**165.24** (8.52)	13.66 (0.72)	**-133.18** (-8.91)	**384.89** (9.89)
R Squared	0.08	0.04	0.00	0.04	0.05

Note: t statistics in parentheses. Bolded coefficients are statistically significant at the 5% level

The non-business indicator variable is statistically significant for all sources except the San Juan basin. The estimated coefficients reveal a drop in Canadian and Rockies flows during winter weekends and holidays but an increase during the injection season. The winter drop represents 16 percent of business-day Canadian flows and 12 percent of business-day Rockies flows. Summer flows from those two regions are significantly larger on weekends than on weekdays. Those patterns are reversed for Permian flows which are 14 percent larger weekends than weekdays during the winter and 8 percent smaller on summer weekends than summer weekdays.

Cycles in supply patterns pose more difficult modeling challenges because of the linkages with the consumption, storage and linepacking decisions in upstream locations. The weekly demand cycle for a residential customer in California will have the same shape as for a residential customer in Chicago. However, if the proportion of natural gas consumed by residential customers in Chicago is different to California residential customers, the net weekend demand shift in Chicago might be also different. Because Chicago competes with California for Canadian gas, the Chicago's demand shift could have a noticeable impact on Canadian gas availability for California on the weekends. Therefore, information about the demand structure in those market centers that compete more directly for gas with California –Pacific Northwest, Illinois, Nevada, Arizona and New Mexico– would be helpful for estimating the residual supply curves faced by California from each of the producing regions (Table 4).

Table 4: Consumption Shares by Customer Type in Selected States in 2005

	Arizona	California	Illinois	Nevada	New Mexico	Oregon	Washington
Residential	0.12	0.22	0.45	0.16	0.27	0.17	0.29
Commercial	0.10	0.11	0.21	0.12	0.19	0.12	0.19
Industrial	0.05	0.36	0.27	0.06	0.20	0.31	0.26
Electricity generation	0.72	0.31	0.06	0.66	0.33	0.39	0.26

Source: Department of Energy, Energy Information Administration.

Table 4 offers two insights: First, the share of natural gas consumption corresponding to electricity generation is very large in Arizona and Nevada. Those two states compete directly with California for Southwest and Rockies gas respectively. When demand for electricity generation peaks (summer weekdays), the availability of gas from the San Juan and Permian basins to California might be reduced due to relatively larger demands at upstream locations than in California. Second, the share of natural gas consumption by residential customers is larger in Illinois than in California. Therefore, the winter weekend peak in natural gas requirements will be relatively larger in Illinois and might reduce available Canadian flows for California during those periods.

Utilities, pipelines and off-system customers have two tools for balancing out the within-week fluctuations in consumption and flows: underground storage and linepacking. Both of them are endogenous variables in the daily simulation model. These two activities are characterized by capacity constraints and by their marginal costs, which involve fuel losses due to compression. Information about these costs has proven very difficult to obtain. One of the tests for evaluating the quality of the model's calibration will be to compare the simulated and actual profiles for underground and pipeline inventories. The actual within-week cycles based on daily data for the April 2001 through March 2005 period are presented in Tables 5 and 6.

Table 5: Estimated Coefficients from Regressions of Storage Net Injections on Non-Business Day Indicator Variable

	PG&E	Wild Goose	Lodi[3]	SoCal Gas
Coefficients	0.71 (0.07)	-2.75 (-1.08)	**-23.37** (-4.13)	**-69.13** (-4.16)
Non-Business Days	**-193.95** (-7.76)	**-52.04** (-8.37)	**33.68** (2.43)	**-153.25** (-3.77)
Non-Business Days* Injection Season	**431.95** (14.18)	**121.08** (15.98)	**119.85** (7.09)	**746.92** (15.06)
R Squared	0.32	0.16	0.12	0.17

Note: t statistics in parentheses. Bolded coefficients are statistically significant at the 5% level.

The results in Table 5 are partly reflecting the intense seasonality in storage operations. Together with the results on Table 1, the observed patterns on underground storage at utility-owned facilities and Wild Goose tell a consistent story. Total gas requirements in California are larger in winter weekends at which time underground storage will have to be heavily drawn down. In contrast, during the injection season gas demand is larger on weekdays than weekends. Inventory accumulation, therefore, peaks on non-business summer days.

At Lodi, weekend net injections are, on average, positive all throughout the year. This facility has the highest deliverability among all the ones in California and is more geared towards those customers who want to engage in short-term, speculative storage operations. Lodi is considered the most price-responsive storage facility in California (Uría and Williams 2007). Natural gas spot prices also display a weekly cycle characterized for a slight drop at the end of the business week and reversed on Mondays. The behavior of Lodi would be consistent with trying to take the most advantage of that predictable price variation.

[3] Lodi started operation on January 2002. The regression for this facility covers the period April 2002 through March 2005.

Table 6: Estimated Coefficients from Regressions of PG&E System Inventory Change on Non-Business Day Indicator Variable[4]

	PG&E Daily System Inventory Change
Coefficients	**-24.77** (-5.83)
Non-Business Days	**74.50** (7.15)
Non-Business Days*Injection Season	-2.55 (-0.20)
R Squared	0.06

System inventory change is the difference between the amount of gas supplied to and released from PG&E's backbone pipelines. According to the results in Table 6, pipeline inventory changes are largest on non-business days with no significant differences across seasons. The average inventory change on business days is negative (i.e., gas packed in the pipelines during weekends tends to be released during weekdays).

Tables 1 through 6 have shown definite intraweek variation in the demand and the supply side of the California natural gas market. A large amount of information, therefore, would be lost in a seasonal model. A model disaggregates enough to account for weekly cycles are necessary to take efficient decisions about logistics and to identify short-term profitable arbitrage opportunities. Compressor capacities at storage facilities or on pipelines constrains flows on weekends or weekdays rather than steadily through the month.

1.3 Implications of Seasonal and Weekly Cycles for Modeling Storage in California

The strong cycles in natural gas storage within California, whether the widely known seasonal cycle or the less known weekly cycle, indicates that any model of infrastructure involving California needs to include underground storage. If the quantities involved were a small percentage of typical daily flows, it would be a reasonable simplification – any model requires some simplification – to ignore underground storage. By that logic, the strong diurnal cycle in consumption of natural gas is not included in the model presented here, because the cycle is absorbed by the linepack within pipelines rather than by underground storage. Underground storage facilities do not reverse the direction of flows every twelve hours, for physical reasons. Because underground storage facilities do react to the weekly cycle, the model here includes that cycle at the level of simplification of weekdays/weekend.

[4] Similar data for SoCal Gas or the Kern River pipeline were not available at the time of this report.

The observed seasonal and weekly cycles in California underground storage are themselves responses to underlying cycles in weather and economic activity. More important, they are responses in accord with cycles everywhere else within the North American natural gas network. It matters that winter is colder than summer in California, but also that California's winter is much less cold than Illinois's. A network model such as presented here is actually a representation of relative seasonal and weekly cycles. Those interplays are more complex. If California not part of a larger network with different magnitudes to the cycles, a network model emphasizing California would probably offer few new insights.

For similar reasons, a network model is probably unnecessary if the policy choices involve small changes. A cost/benefit analysis of an increase in storage capacity of 0.1 percent at one facility or a 0.1 percent increase in compressor capacity for a pipeline could use existing price profiles. However, substantial changes in capacities would likely alter the price profiles substantially throughout California. A network model, once calibrated using historical data, can help predict these extensive changes. Broad categories of scenarios are infrastructure expansions (pipeline and storage), regulatory rules and changes in supply and demand profiles. More specifically:

- How would the value of existing storage capacity be affected by introduction of liquefied natural gas (LNG) in the system? Would additional storage capacity be needed? Where? How would the weekly flow pattern change if LNG came into the system as a surge each time a cargo arrives?
- What is the optimal size of the *interconnect* and the optimal intrastate flow profile if West Coast LNG regasification capacity is built in Oregon versus South or Baja California?
- How much do the regulatory requirements about storage for core customers constrain the whole network?
- How sensitive are the optimal flow and storage profiles to different relative sizes of winter versus summer demand peaks? To different weekday versus weekend demand requirements? To different official balancing requirements –daily, weekly, monthly?
- Would additional pipeline capacity or would additional storage capacity be more effective for responding to increased variability in demand (due to the increasing share of renewables, which are intermittent sources of energy, and due to combined cycle generation plants serving electricity demand peaks)?

The typical cost/benefit analysis of a proposed infrastructure addition and the tariff envisioned for the finished project imagines the project to be used almost continuously. This assumption is problematic because of seasonal or weekly cycles. For example, a pipeline can operate near to full capacity during the summer because of the flows into underground storage. Less obvious, the underground storage facility can smooth those seasonal pipeline flows only because its compressors are idle at least half the year. In any network of storage and pipelines (and in any model of such a network), the economic pressure is to trade off which times at which places which types of equipment are idle

CHAPTER 2:
Project Approach

The model developed in this project belongs to the class of spatial equilibrium models, which has a long tradition in economics. (Enke 1951) offered an early formulation of the spatial equilibrium problem: find equilibrium quantities, prices, and flows given supply, demand, and transportation costs. He introduced an analogy with an electrical circuit, in which various power sources are the locations and the resistance in the wires is the cost of transportation. No economist has actually solved a spatial equilibrium problem by Enke's method, however. (Samuelson 1952) cast the equilibrium problem into a social welfare maximization framework that can be solved using mathematical programming. In his influential paper, the areas under excess supply and demand curves are compared to the area under the transport cost curve to compute a "net social payoff" from trade among four regions. (Takayama and Judge 1971) also made important contributions to this class of model. They defined "locational price equilibrium": the difference in price between any two locations will be exactly equal to transportation cost if they are actually trading and smaller or equal if no trades are occurring. They also expanded this class of model to include seasonal storage.

As the methodology of spatial equilibrium models advanced, early simplifying assumptions were relaxed, namely, fixed quantities demanded and/or supplied and perfectly elastic supply of transportation services. Other extension to the basic problem, which is crucial for the model presented here, consists in making it dynamic. A dynamic model has multiple periods, which are interconnected. In a daily model of the California natural gas network, decisions about flows and consumption on one period are not independent of decisions taken in previous periods. Underground stocks and linepack, both resulting from decisions in earlier periods, provide the links among periods.

Spatial equilibrium models have been used extensively to analyze trade in agricultural commodity markets. (Bivings 1997), for example, employed a nine-location and 12-month mathematical programming model to understand the regional and seasonal effects of Mexico's decision to remove import quotas on sorghum. (Bohn, Caramanis, and Schweppe 1984) provide an example of the use of this methodology in the context of an energy network. A similar model including storage is used in (Gabriel et al. 2000) to determine whether Canadian gas exports to the United States would be affected by increased gas demand in Canada due to environmental concerns.

These spatial equilibrium models might be better classified as "no-arbitrage" models. These models seek to find the pattern of prices, trade flows, and inventories such that no simple arbitrage opportunities exist, arbitrage opportunities such as buying in one location and simultaneously selling somewhere else at a price differential that exceeds the prevailing fee for transportation. Usually, these models do not distinguish specific agents and their decision-making, at levels such as gas producers, pipeline, marketers, and distribution companies. Nor do they models usually allow for the exploitation of market power. (Exceptions are (Egging and Gabriel 2006), who consider the oligopoly in the supply of natural gas to Europe, and (Gabriel, Zhuang, and Kiet 2005), who model strategic interactions among gas marketers.) Those variants that do must sacrifice some detail in locations and time, or the model becomes too complex to solve.

These models, even those with specific types of agents, do not purport to describe how the prices, trade flows, etc. reach the new equilibrium should something fundamental change, although sometimes economists using them slip into describing the numerical solution technique they use as the method by which actual markets achieve no-arbitrage pricing relationships. These models offer the most insight when a fundamental change is large, as when a pipeline doubles in capacity rather than increases by 0.1percent. They are particularly helpful in revealing indirect effects, as when the change in conditions increases trade flows from one location to another, thereby advantaging producers in yet a third location who might have otherwise have had to compete with those exports.

Models in this class can be interpreted as determining the pattern of imports and storage that minimize the cost of procurement. That is, the mathematical programming model in this project can be thought of as describing a single large utility for California, although not one that exploits its dominant buying power in particular supply regions. The model aims at identifying the least-cost daily allocation of flows and inventories for California over a one-year period. The solution to the problem will be largely determined by the interplay among the following underlying conditions:

- Seasonality and within-week demand profiles for different customer types in different parts of California.
- Seasonality and within-week patterns in the flows from the various producing regions serving California throughout the year.
- Seasonality and within-week patterns in the trade-offs between linepack and underground storage costs.

If these interplays were obvious, the mathematical programming model would not be necessary.

2.1 Basic Structure of the Model

The seasonal patterns were already studied in the monthly version of the model (Uría 2006). That model represents the California natural gas network as a system in which four activities – demand, supply, transportation and storage – take place month by month. The output for each month´s allocation is characterized by 65 endogenous variables: 34 are flows along each feasible path to each customer type, 24 are injections or withdrawals for each feasible facility-region-customer type combination and the remaining 7 are consumption levels for each customer type and demand region. Fuel loss percentages, supply and Citygate prices and storage levels are all determined using the basic endogenous variables. Storage connects the months. Demand, supply and transportation cost curves are linear. Because these functions are linear, the objective function, namely the net social payoff in Samuelson’s terminology, is nonlinear. Specifically, from a numerical methods perspective, the model is a quadratic programming problem.

The three demand regions considered correspond to the two big natural gas distribution utilities in California, namely PG&E and SoCal Gas, and off-system customers.[5] The five supply regions included in the model represent each of the producing areas from which California gets its gas: western Canada, Rocky Mountains, San Juan Basin, Permian Basin, and in-state production. The infrastructure elements included in the model are: five receipt points along the California border, namely Malin, the receipt point for the Kern River pipeline in San Bernardino County, North Needles, Topock and Ehrenberg; four storage areas, namely those PG&E-owned, those SoCal Gas-owned, Wild Goose, and Lodi; and the utilities´ main backbone pipelines and interconnects among them at Wheeler Ridge and Kramer Junction. Malin connects only with PG&E; Ehrenberg only with SoCal Gas transmission infrastructure; the other receipt points connect with both utilities. Therefore, the simulated network has 7 nodes and 12 arcs.

The change from a monthly to a daily one-year model is too large to be accomplished in just one step. Instead, the researchers opted for developing a one-month daily model as an intermediate step. Such a smaller model, to be presented in the next section, allows clarifying many of the calibration issues that arise from inclusion of within-week patterns without the large computational burden that the full model would impose.[6] The results from the month-long daily model when applied to several representative months implied that the distinction between weekends and weekdays sufficed.

2.2 Adjustments for Including Weekly Cycles

The demand curves from the seasonal version of the simulation model provide the starting point for modeling the consumption activity in a daily model. The monthly natural gas demand curves were indexed by demand region –PG&E, SoCal Gas, and offsystem– and type of customer –core, noncore industrial and noncore electricity generation. They were calibrated using a reference point –observed monthly utility sendouts to their respective systems and price at the California border– and an estimate of the demand elasticity for each customer type.

The estimated weekend consumption changes presented in Tables 1 and 2 were inputted into the mathematical programming model as demand curve shifters. Although the regressions in Tables 1 and 2 ignore factors that are important for determining the quantities demanded on a given day, they are useful nonetheless as a first approximation to the average shape and size of weekly cycles needed for calibrating the mathematical programming model. The calibration technique used in the version with daily periods is similar to the one used in the monthly model. The transition between average consumption by group j in month t and in month t+1 is

[5] Off-system customers are the industrial customers and electricity generators who bypass the utilities and are served directly by the Kern River pipeline.

[6] The relationship between the number of periods and the time taken by the non-linear programming algorithms to solve the problem is non-linear. Model runs of the one-month daily models took, in average, 5 minutes to solve. Model runs with a two-month model took up to one hour and a half to achieve a feasible solution.

assumed to happen smoothly in four steps, one per week. Then, for every week, the estimated shifts are applied to the weekend periods.

The supply activity required similar adjustments to incorporate the estimated weekend shifts in flow volumes, which were presented in Table 3. The monthly gas supply curves were indexed by producing region –Canada, Rocky Mountains, San Juan, Permian and California production. They were calibrated using a reference point – observed production at each of the supply basins and price at representative hubs. The selected pricing points are NOVA-AECO for western Canadian gas, Opal for Rockies gas, El Paso Bondad for San Juan gas and Waha for Permian gas. Thus, the model acknowledges that the price paid by customers in California for gas from out of state depends not only on how much gas they demand but also how much is consumed in upstream locations.[7]

In the monthly version of the model, linepack fluctuations are not considered. The balancing constraint by which customers must keep the total monthly amounts brought into and released from the pipeline system within a certain band should result in negligible net changes in linepack month to month. However, fluctuations in linepack are significant at the weekly level. Thus, variables and equations to represent the evolution of pipeline inventories need to be included in the daily version of the model.

The linepacking activity is characterized by means of the upper and lower bounds that pipeline inventories can reach in the PG&E, SoCal Gas, and Kern River systems.[8] The costs of linepacking are modeled as fuel losses incurred by the use of compressors to "pack" and/or release pipeline inventories. The fuel costs of packing are assumed to be lowest when pipeline inventory is at the lower bound. As linepack increases, fuel losses increase nonlinearly.

The inclusion of linepacking increases the complexity of the model. This activity brings in a new dynamic component (along with underground storage). The tradeoff between injections and withdrawals from underground facilities versus pipelines will be a main driver of the model. The monthly balancing constraint conveys the idea that storage within pipelines is a short-term option. The relative cost functions for both activities determine the timing and volumes of gas injected into and withdrawn from pipelines and underground reservoirs.

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[7] As regards California production, the price used corresponds to information collected by the California Energy Commission about prices paid to producers in the Sacramento Valley.

[8] Upper and lower bounds for the PG&E system were obtained from the Pipe Ranger website. For the SoCal Gas system and Kern River pipeline those bounds were inferred using a similar receipt capacity/system capacity ratio as that observed for PG&E.

2.3 Parameters Used

Table 7: Selected Base-Case Parameters

Demand elasticity	Core	-0.38
	Non-core	-0.33
	Electricity generation	-0.61
Supply elasticity	Canada	0.45
	Rockies	0.31
	San Juan	0.94
	Permian	0.48
	In-state production	0.62
Discount rate per month		0.0025

The choice of the demand and supply elasticities was partly a result of an econometric analysis using monthly data for 2001-2005 and partly a result of a trial and error process centered on the estimated coefficients and focused on obtaining the best calibration to the observed patterns in the reference period (2006-2007 for the full one-year daily model) (Table 7).

The econometric analysis of monthly average consumption and price data reveals inelastic demand curves. The regression uses as explanatory variables a trend, periodic -sine and cosine - functions to capture deterministic seasonal patterns and heating and cooling degree days. Because quantities consumed and prices are both endogenous variables, the regressions were estimated by two-stage least squares using lagged prices, lagged West Texas Intermediate (WTI) oil price and lagged degree days as instruments. Two-stage least squares was also the method of choice for estimating supply elasticities. The explanatory variables were the spot price representative of each of the producing regions, a trend, the number of rigs at each producing region and degree days. The price of WTI oil and lagged degree days were the instruments for the first stage regressions. All the estimated elasticities display the positive sign that would be expected for a supply relationship.

2.4 Results from One-Month Daily Model

The one-month model serves as a preliminary step to the calibration of the full model. The one-monthly daily version (28 periods) was run for April, August and January. Modeling several months allowed assessing if the simulated weekly cycles, particularly for underground and pipeline storage, showed similar seasonal differences than the observed ones.

Figures 4 through 6 display the simulated consumption and flow profiles for April, using the weekly shifts for supply and demand presented in Tables 1-3. The shifts were applied to the intercept of the supply and demand curves on weekend periods. Thus, it is a parallel shift – same quantity change for any price level.

Figure 4: Simulated PG&E Consumption Profile (April)

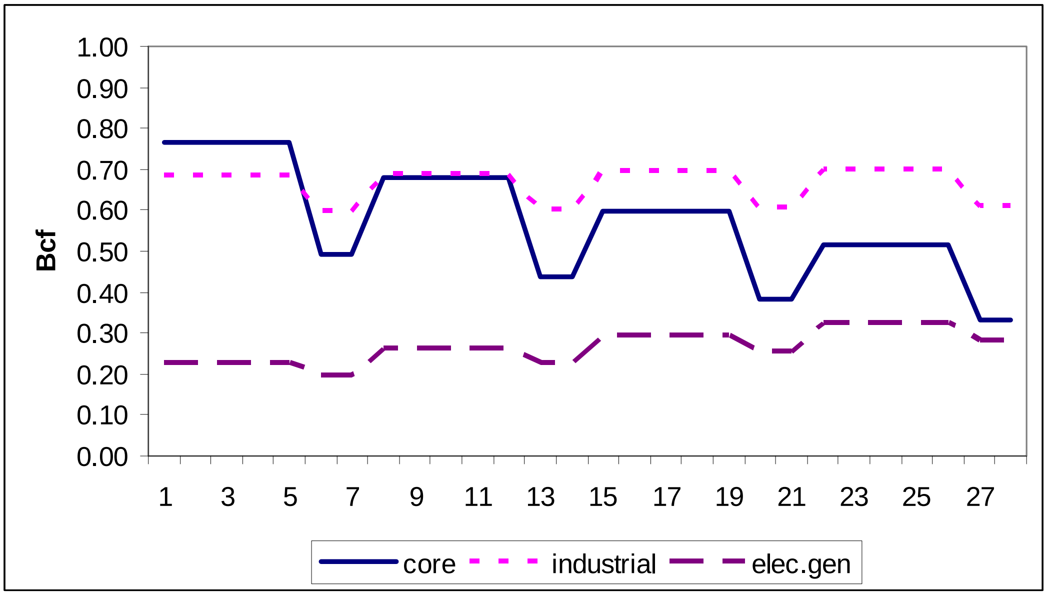


Figure 5: Simulated SoCal Gas Consumption Profile (April)

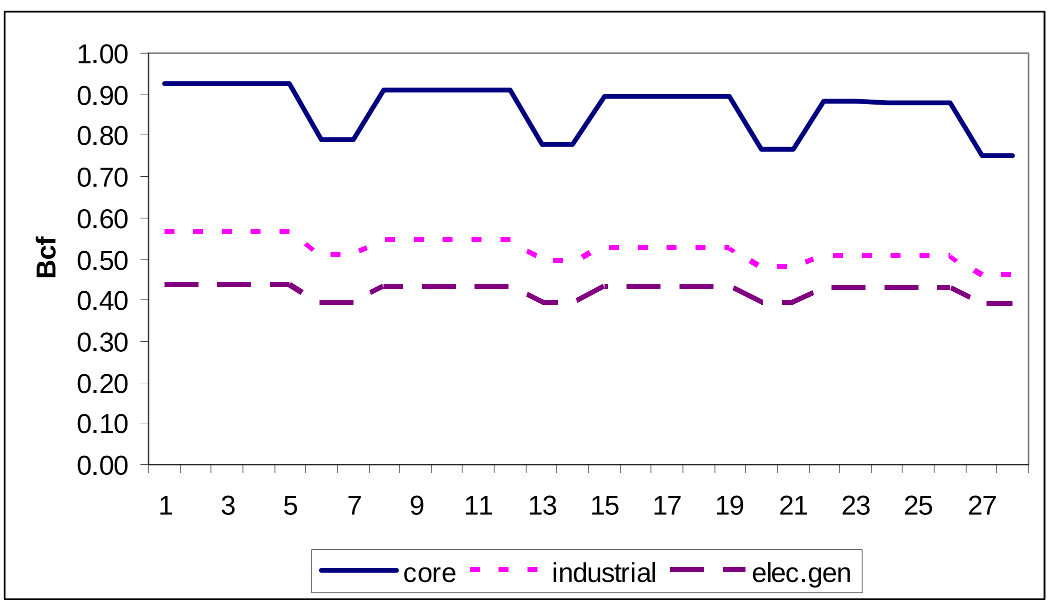
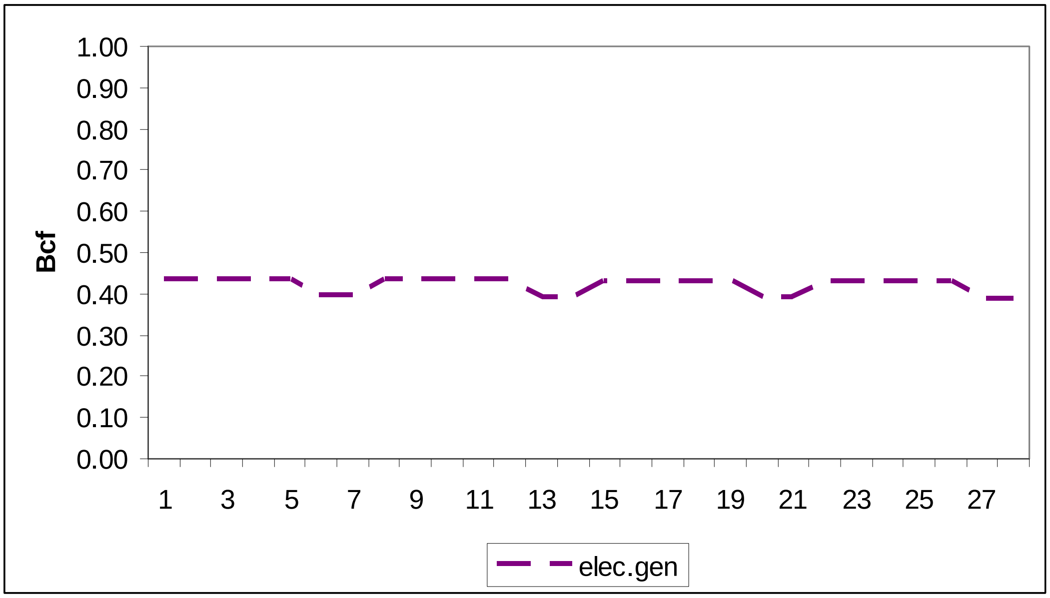


Figure 6: Simulated Offsystem Consumption Profile (April)



The simulated cycles in Figures 4-6 replicate the demand patterns inputted in the model, with sequential weekly steps toward May consumption levels. For industrial and electricity generation customers, the volumes consumed are similar in April and May. For core customers, consumption in May is lower than in April. Simulated consumption is lower on weekends than on weekdays for all seven customer groups. No variation exists across weekdays or between Saturdays and Sundays. Such a result is sensible given that the supply and demand curves only shift weekends versus weekdays and from one week to the next.

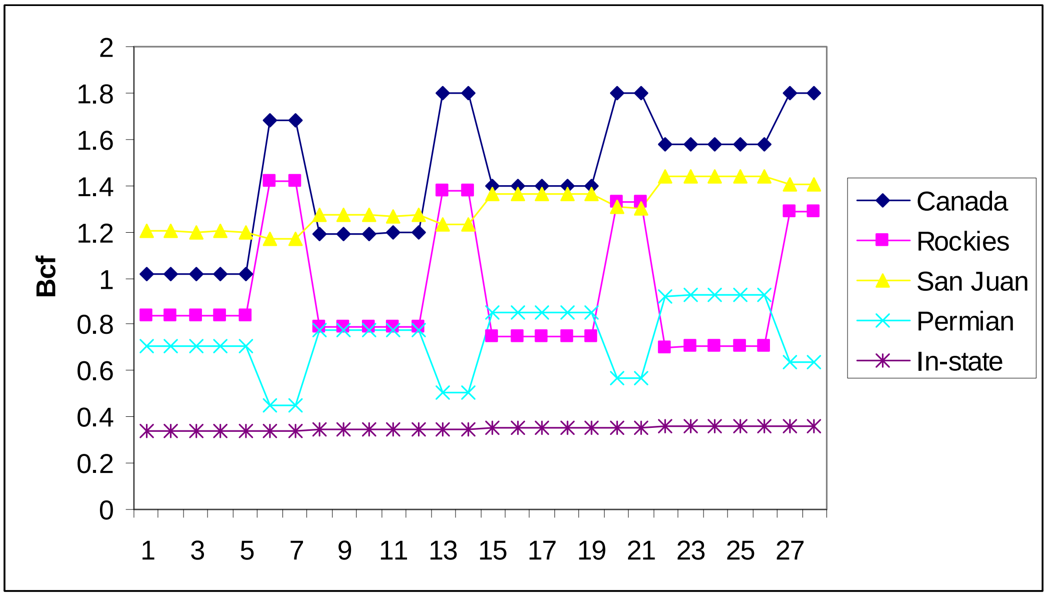


Figure 7: Simulated Flow Profile by Producing Region (April)

The simulated profiles in Figure 7 replicate the results observed in Table 3 for a month that belongs to the injection season. Canadian and Rockies flows are larger on weekends than on weekdays while the opposite is true for flows from the San Juan and Permian basins. In-state production behaves as a base-load volume, one that remains approximately constant all throughout the month.

The starting values for flows, consumption and prices are the reference values used to build the supply and demand curves. The algorithm initiates its search for the optimum from those values. Thus, if a local rather than global optimum is found, the solution will be close to the values to which the model needs to be calibrated. For pipeline and underground inventories, however, only one reference value –the one for the very first period– is inputted in the model. Thus, they are the key variables for assessing model calibration.

To some extent both underground storage and linepack management have the same role in a one-month model. Demand seasonality, the main driving force for explaining injection and withdrawal patterns into underground storage facilities, is absent from a one-month model. Here, inventories and linepack are perfect substitutes for buffering the weekly demand cycles except for possible differences in the following two items:

- Fuel loss functions. The assumed fuel loss is constant for underground storage and linearly increasing with pipeline inventory in the case of linepack. Depending on the assumed initial linepack value, it might be cheaper or more expensive to use underground storage or linepacking. The tariffs of each storage facility offer information about the average fuel loss resulting from injecting gas. However, no data on linepack fuel losses were available. Preliminary runs of the model revealed that when the fuel losses associated with packing gas in the pipelines were larger than those of injecting gas into storage reservoirs linepacking activity was close to zero. In order for the model to replicate the significant observed fluctuations in linepack, the assumed fuel loss curves are such that the maximum percentage loss is 2 percent.

- Salvage values of end-of-month inventories versus linepack. If no salvage value was imposed, it would be optimal, from a social welfare maximization perspective, to deplete inventories by the end of the month. Given that the model aims at replicating observed patterns, value should be attached to end-of-month stocks either in underground storage or pipelines. The assumed salvage value for both equals the reference California border spot price for the following month.[9] In the full year model, the shadow values of both types of inventories should be different at several times of year. For instance, the ability to pack additional units in the pipelines might not be very valuable at the beginning of the injection season but will become more so as the summer progresses and underground storage fills up. Similarly, linepack would be especially valuable in responding to demand peaks at the end of the winter season when most underground inventories have already been used up.

The simulated linepack profiles for April, August and January are presented in Figures 8 through 10. These simulated profiles correspond to a model version that includes a monthly balancing constraint by which additions to and subtractions from linepack must cancel out throughout the month.

[9] For larger salvage values, an additional unit of gas is more valuable underground or "packed" than if released on the market making it optimal to fill up storage capacity. For smaller salvage values, an additional unit of gas is less valuable underground or "packed" than if released on the market making it optimal to deplete inventories.

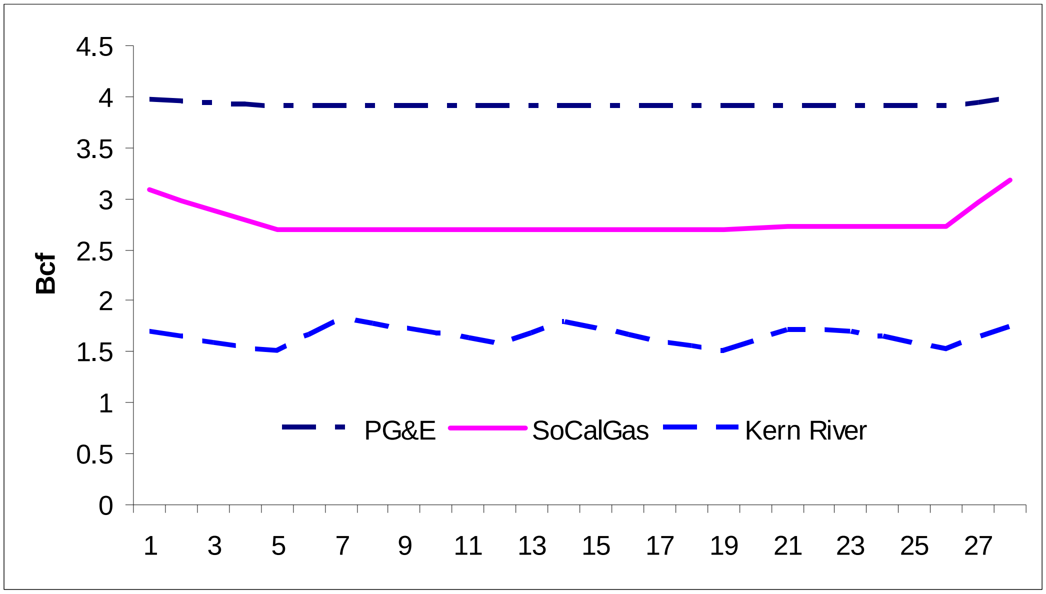


Figure 8: Simulated linepack profiles (April)

The simulated profile for April reveals clear weekly cycles only in the Kern River pipeline. The simulated cycles for Kern River are very regular with linepack being built up during the weekends and drawn down Monday through Friday. In the SoCal Gas system, the initial drawdown in pipeline inventory is only offset in the last weekend of April. The PG&E system does not experience any fluctuation in linepack during this month.

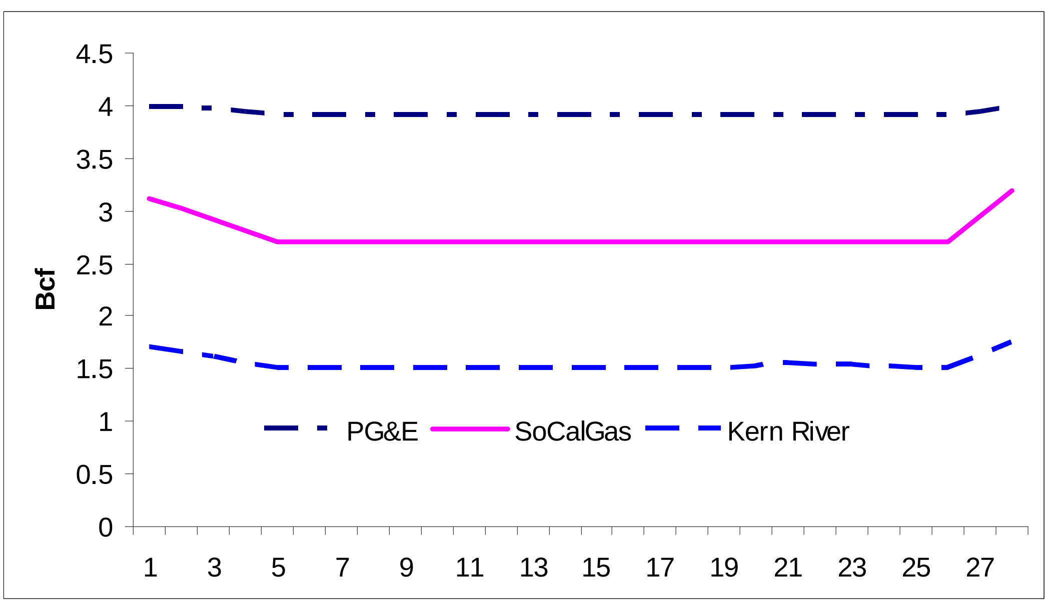


Figure 9: Simulated linepack profiles (August)

Simulated linepacking activity is very low in August. All pipelines display an approximately constant linepack level close to the midpoint of the range of allowed pipeline flows. The initial release of pipeline inventories offset by packing during the last weekend of the month is sensible given the assumed demand profile. The reference quantities demanded decrease progressively week after week –September natural gas requirements are, for most customer types, smaller than those in August. Therefore, gas is more valuable in the market than in the pipeline at the beginning of the month, while the opposite is true at the end of the month.

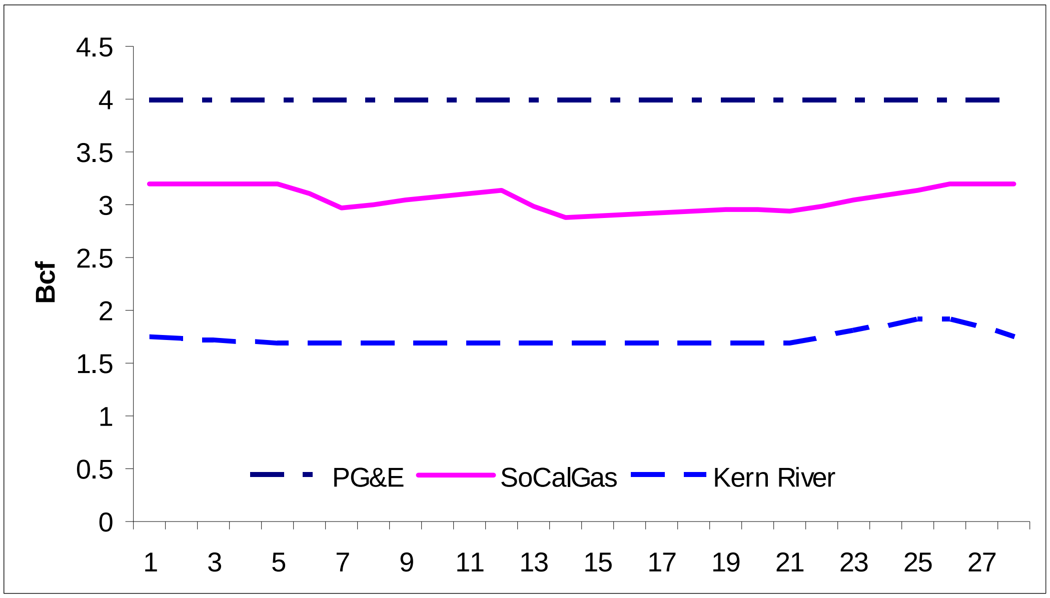


Figure 10: Simulated linepack profiles (January)

The simulation results for January show linepack cycles on the SoCal Gas system while the volumes of gas packed at the PG&E and Kern River pipelines stay constant throughout the month. Pipeline inventories in the SoCal Gas system are built up Monday through Friday and drawn down during the weekend. Such pattern is sensible given the assumed winter demand shifts presented in Table 1. Customers in Northern California and along the Kern River pipeline would, according to the simulated linepack behavior, choose to withdraw gas more heavily out of underground storage facilities than those in Southern California.

All in all, simulated fluctuations in linepack for this one-month version are much less prevalent than actually observed in the system. According to this model specification, it would be optimal for PG&E customers not to use pipelines at all as a means of storage on those three months. However, when the simulated underground storage activity is precluded, the simulated linepack profiles display weekly cycles. Figure 11 shows the simulated pipeline inventories from a model specification with no underground storage for April.

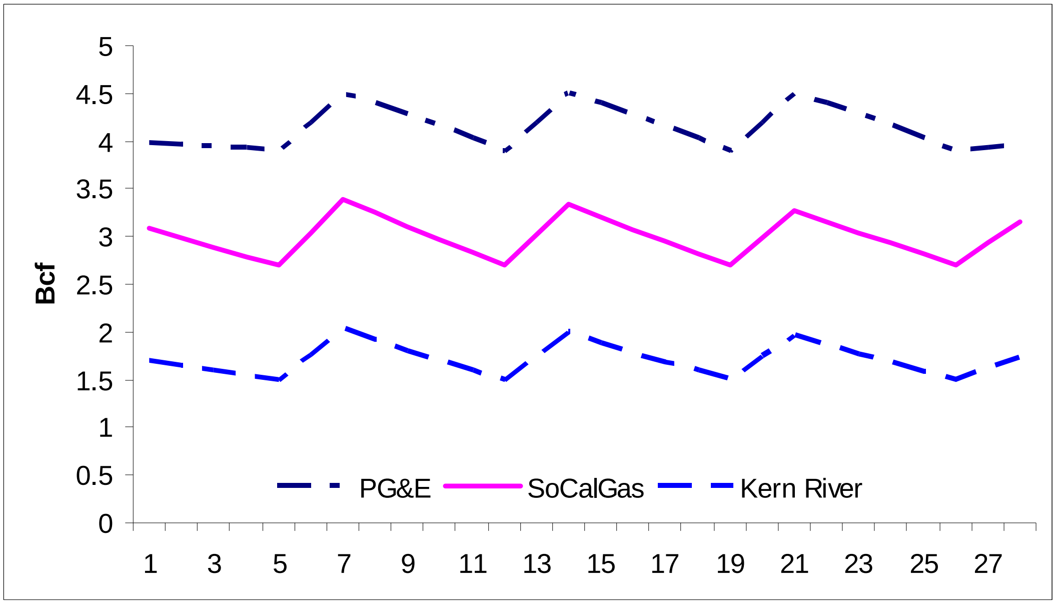


Figure 11: Simulated Linepack Profiles (No Underground Storage, April)

The other control variable in the system is net injection into underground storage reservoirs. Figures 12 through 14 contain the simulated daily storage load factors for April, August and January at each of the storage reservoirs in California.

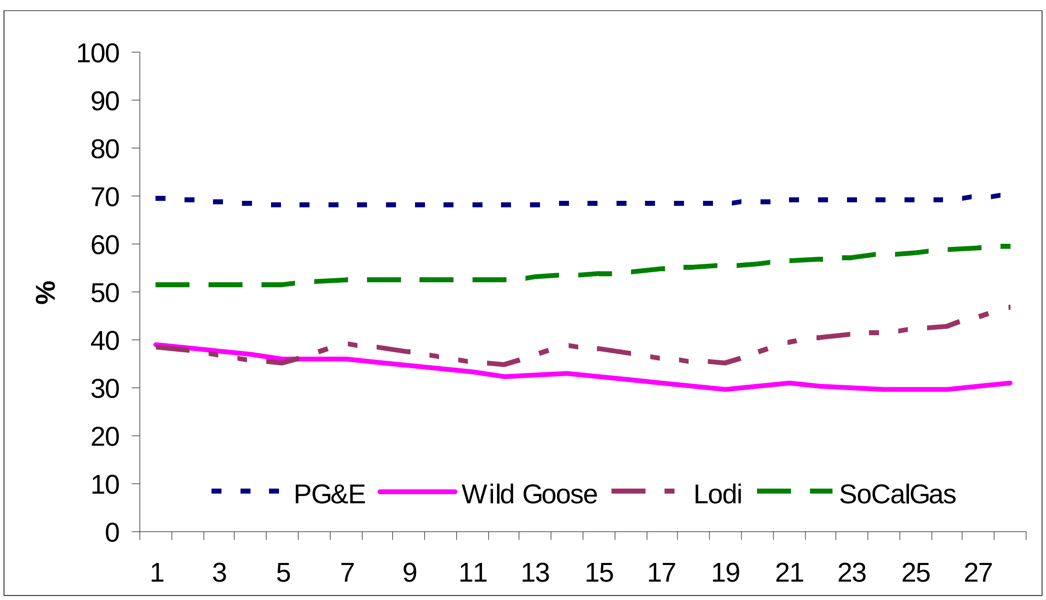


Figure 12: Simulated Underground Storage Load Factors (April)

Facilities in Northern California display very different profiles in April. The level of stocks at utility-owned facilities stays approximately constant, Wild Goose releases inventories over the month and Lodi cycles gas on a weekly basis. In contrast, net injections are positive in the SoCal Gas service area.

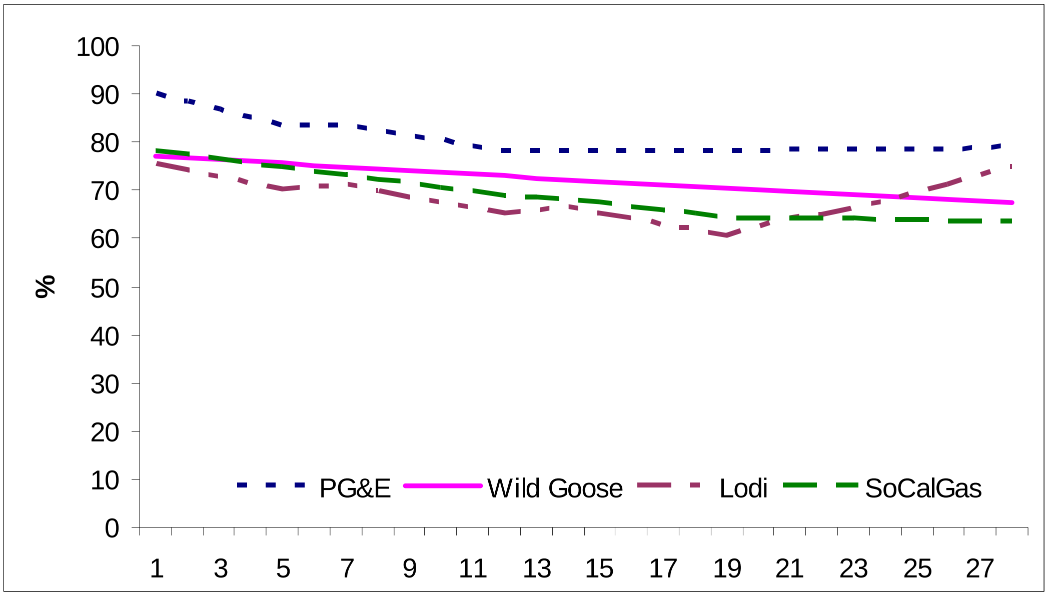


Figure 13: Simulated Underground Storage Load Factors (August)

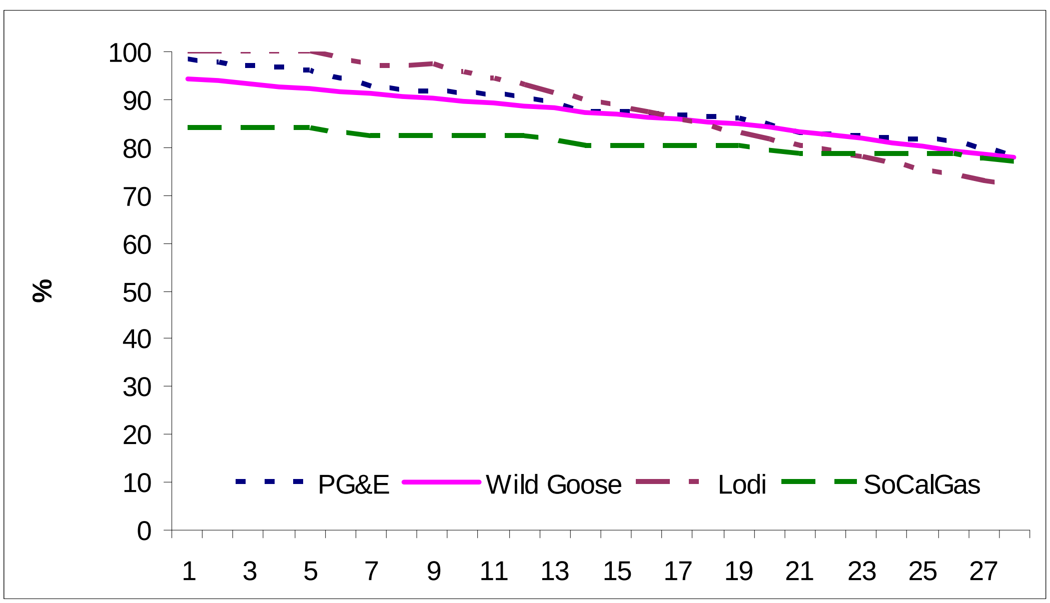


Figure 14: Simulated Underground Storage Load Factors (January)

In August and in January, net injection is negative in every storage facility (except for Lodi in August). The reference quantities demanded are smaller at the end of each of those months than at the beginning and, therefore, in a one-month model, withdrawing gas is sensible. Reference prices, however, drop significantly over August but increase over January. In both cases, simulated Citygate prices are approximately equal to the salvage values of underground and pipeline stocks. This equality should characterize the optimum allocation; otherwise, the objective function value could increase by either injecting or withdrawing additional units from one or both forms of storage.

2.5 The Appropriate Temporal and Spatial Disaggregation

Once the one-month daily model has been solved, the following step is to extend the planning horizon from one month to one year. Solution times increase rapidly as additional periods are included. For instance, a four-month daily model takes over 20 hours to be solved. Because the model focuses in simulating and analyzing seasonal and weekly cycles, fifty-two quantity and price pairs - one per week – suffice to calibrate the supply and demand curves. Thus, there are no differences across days of the week or between Saturday and Sunday in the demand, supply or cost information inputted in the model. Consequently, simulated results in any of the activities - supply, demand, transportation, storage or linepacking - differ only between weekdays and weekends. Even though day-to-day variability also matters, it does no longer respond to regular patterns but to short-lived temperature spikes or unpredictable disruptions in the system. Those shocks are not the focus of this model.

Thus, the main model has 104 periods – week and weekend *times* four weeks per month *times* 13 months per year – rather than 364 periods – seven days *times* four weeks per month *times* 13 months per year. The 13^{th} month allows having a total of 52 weeks and facilitates comparison of simulated and observed profiles. Thus, the main model has two types of periods with different durations. A scaling factor accounts for the different duration of week versus weekend periods. Daily volumes were obtained scaling back simulated results, the implicit assumption being that volumes are identical Monday through Friday and change over the weekend.

Although the model here is limited to a single natural gas year, other models of natural gas storage have a time horizon of fifteen years, and even twenty-five years. Such multi-year models may not be preferable. First, they achieve that greater complexity inter-year by sacrificing details intra-year, such as using months instead of weekdays/weekends and ignoring linepack. Second, the one-year model used here can be interpreted as being multi-year. It includes so-called salvage value for any carryover into the next natural gas year. That salvage value can represent the allocation decisions across many years, just as the residual supply curve in a producing region can represent the interactions among the many other demand regions it serves. Third, only if the salvage value is sufficiently high so as to induce carryover within California to the next gas year is it relevant to the first year's seasonal and weekly cycles. Without inter-year carryover, a multi-year model would revert to a series of one-year models, and is more easily solved in that form.

Intuitively, the level of detail about infrastructure must be increased along with the degree of temporal disaggregation. For a monthly model, a picture of the network including only the interstate pipelines bringing gas to California and the main backbone intrastate pipelines suffices. The daily variations in demand and supply, however, will likely have more localized effects, on the connections from the backbone pipelines to electricity generation plants or to storage facilities. However, the extra insight provided by the alternative, more detailed spatial configuration to be described in this section did not justify the increased complexity.

In the simple version, gas coming into the PG&E system regardless of its origin could directly serve any customer in the system. In the detailed version, each pipeline serves a group of counties inside the utility service area. Gas exchanges between pipelines are allowed. Restrictions are imposed on who can get gas from each pipeline and who can store gas in each facility. Information provided by PG&E helped understanding the spatial configuration of their system. Line 401 takes Canadian gas at Malin and serves counties north of San Francisco. Line 300 takes Southwest gas at Topock and serves the rest of the counties in the PG&E utility area. All storage facilities in Northern California are along Line 401. Storage facilities in Southern California are around the main market center – Los Angeles – and can be served by either Line 3000 or Line 2000.

The detailed version depicts the same receipt points as the simple version, seven pipelines – line 401, line 300, line 3000, line 2000, Kern, Mojave and line 6900 –, three utilities – PG&E, SoCal Gas and San Diego Gas & Electric Company (SDG&E) – and six final markets. Each of the six demand areas corresponds to a group of counties.[10]

Zone 1:	Humboldt, Shasta, Tehama, Mendocino, Glenn, Butte, Lake, Colusa, Sutter, Yuba, Nevada, Placer, Sonoma, Napa, Yolo, Sacramento, El Dorado, Marin, Solano, Amador, Calaveras, Contra Costa, and San Joaquin
Zone 2:	San Francisco, Alameda, San Mateo, Santa Cruz, Santa Clara, Stanislaus, Merced, Monterrey, San Benito, Madera, Fresno, Kinas, and San Luis Obispo
Zone 3:	Kern
Zone 4:	Santa Barbara, Los Angeles, Ventura, and Tulare
Zone 5:	Orange, Riverside, and Imperial
Zone 6:	San Diego

PG&E serves zones 1 & 2 plus core and industrial loads in zone 3. The Kern/Mojave pipeline serves electricity generators in zone 3. SoCal Gas serves zones 4 and 5. San Diego Gas and Electric serves zone 6.

[10] Not all counties in California are included because some are not served by PG&E or SoCal Gas or SDG&E.

The available consumption data are on-system sendouts by utility and customer type. Weights had to be applied to obtain consumption by customer type and demand area. Weights for core demand are based on county population data. Weights on industrial demand were constructed using data on number of manufacturing establishments per country. Finally, gas-fired power plant capacity data provided weights for electricity generation demand

When aggregated back into utility service areas, results from the detailed version were qualitatively and quantitatively similar to those from the simpler version with California represented by just two regions. Flows among zones reinforced the ideas conveyed by simulated intrastate flows between the PG&E and SoCal Gas systems in the simplified version. However, the detailed version increased the size of the model and notably slowed down solution times. For those reasons, base-case results in this report correspond to the more parsimonious spatial configuration.

The model presented here emphasizes network effects across space and time, yet it does not represent the whole North American natural gas network. Seattle is not explicit, let alone Chicago, New York City, and Toronto. Rather Seattle, Chicago, New York City, and Toronto are implicit in the seasonal and weekly residual supply curve for Canadian gas. Would it not be better to make those other demand nodes and their interactions within the network explicit? The answer would be yes, except that the daily demand data necessary are not readily available and that the focus is on California. Because the supply regions serving California are only indirectly competing to serve other demand centers, the approximation of the full network into residual supply curves is likely to work well. Were the focus on Illinois, much more of the whole network would need to be explicit, because the competition would be direct.

The appropriate spatial scope of this class of network model is actually closely connected to the appropriate temporal scope of this class of network model. Residual supply curves and salvage values are much the same, especially if the salvage value is specified as a function of the quantity carried over to the next year. They are linear approximations to the reduced-forms within a much larger model across many more nodes and many more years. Of course, to prove that the linear approximations used here are sufficiently good would require the full much larger model, in which case it would be used.

The issue of the appropriate spatial and intertemporal scope can be turned around. How sensitive are the conclusions to the assumptions about the residual supply curves and to the salvage value? If not very sensitive, we can be more confident that the spatial and temporal scope of the model is appropriate for studying California. Such sensitivity analysis is integral to following chapters.

CHAPTER 3: The Base Case for a One-Year Weekdays-Weekend Model

This chapter discusses in more detail model specification choices for the one-year daily version. The model uses a base-case specification where demand and supply historical data for the period April 2006-March 2007 are used as reference. The base case constitutes a benchmark against which to measure the effects of changes in the structure and parameters initially specified. The base case could also have been constructed to represent a "typical" year with "typical" seasonal patterns. The definition of "typical" is problematic, however. First, many of the variables in the model display marked trends, in which case the average values are not representative. Also, additions to pipeline and storage capacity create structural breaks in the series, which render a base case constructed with historical averages of the variables less suitable.

The numerical algorithm found an optimal solution for the base-case specification. This statement seems trivial, but in mathematical programming models with this many endogenous variables, a solution is not guaranteed. Indeed, even ten years ago, a model of this complexity would have been beyond the existing numerical algorithms or the existing computers. The interpretation of models with so many variables may remain beyond human capacity of interpretation, nevertheless. In other words, the output of the base-case model is so voluminous as to be a major challenge for presentation. A graphical approach is taken here.

A further challenge is to represent the model relative to the historical data for California. To evaluate the quality of the calibration, the following graphs plot simulated against actual values for April 2006-March 2007 for the key variables: flows, consumption, Citygate prices, underground storage and linepack. Of course, these variables reflect one another. If the model implies a flow through Malin early in the year that far exceeds the observed flow, it is unlikely that the stocks within the PG&E system, consumption, or Citygate prices match well either. These graphs should be interpreted as a set.

3.1 Flows

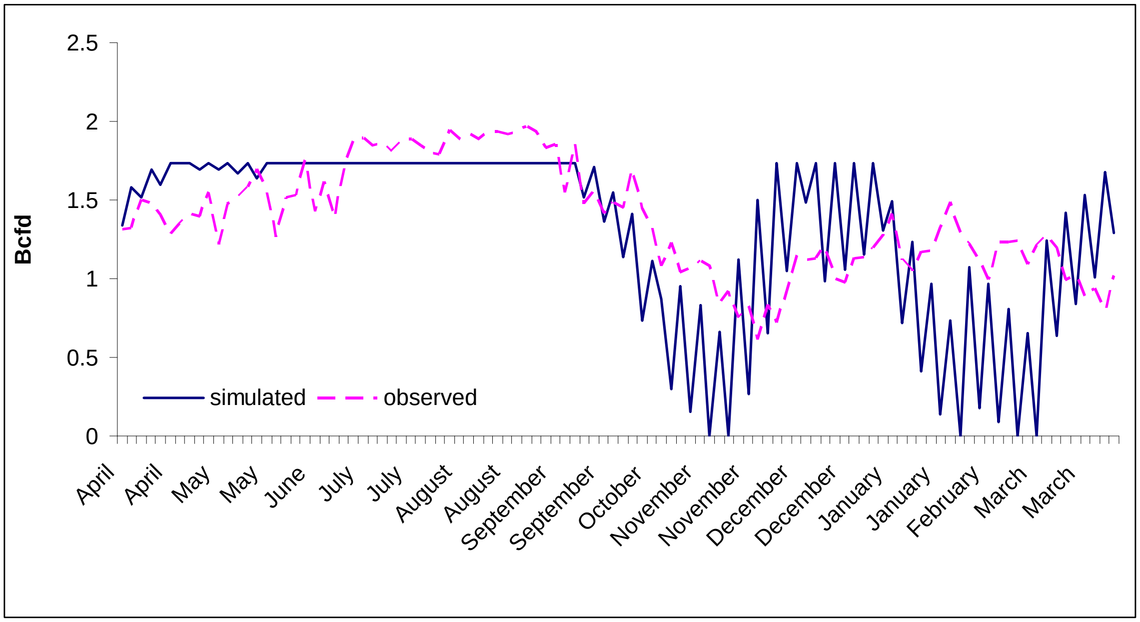


Figure 15: Observed versus Simulated Canadian Flows

Figures 15 through 19 contain the simulated and observed flow profiles for each of the producing regions that serve California as well as for in-state production. For Canadian flows, the model replicates and amplifies the observed seasonality. Simulated Canadian flows are bound by capacity constraints at Malin for most of the injection season. Simulated winter shifts between week and weekend flows are too large. In fact, simulated Canadian gas volumes drop to zero on several winter weekends. Such drops are not realistic. They underline the idea of marked demand pressure from competing markets – Canada, Midwest, and Northeast – on those periods, which would be consistent with relatively larger weight of the residential sector on those market centers.

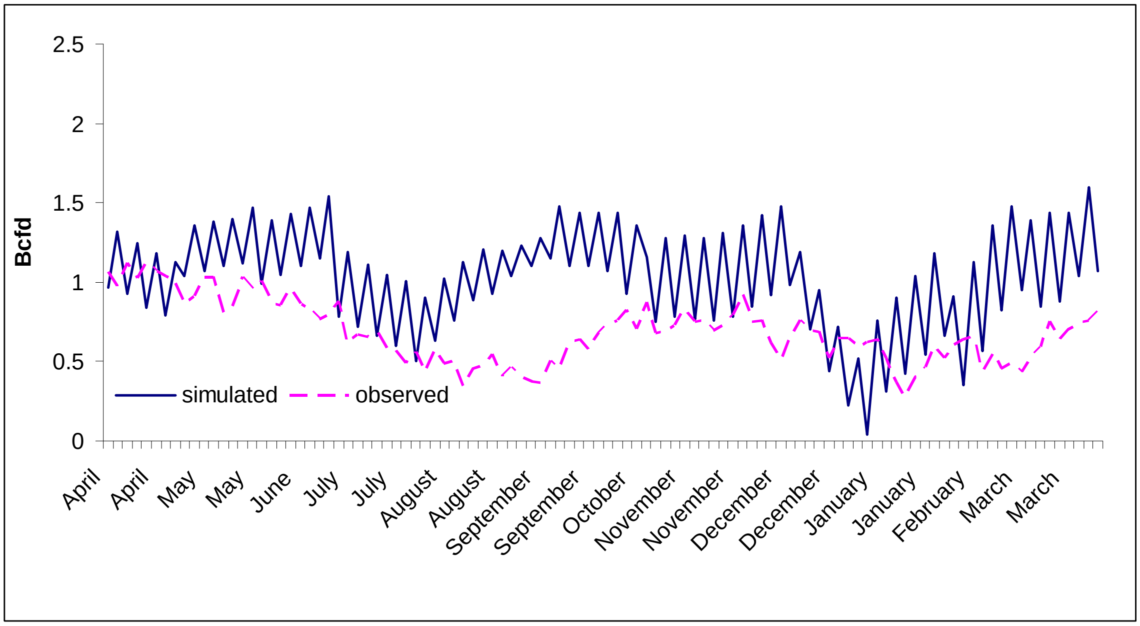


Figure 16: Observed versus Simulated Rockies Flows

Observed gas volumes flowing from the Rocky Mountains into California differ in various aspects from the simulated profile. First, the observed 2006-2007 profile displays a decrease in Kern River pipeline flows in August and September, which the simulation results fail to capture. Prices at the major hubs representative of all the producing regions serving California experienced, in average, $1 increases in August. Rockies gas was relatively more attractive than supplies from the San Juan and Permian basins while capacity at Malin was fully utilized during those months. For that reason the most efficient supply mix would be one with a larger proportion of Rockies gas than actually observed in August 2006. Second, simulated flow shifts between week and weekend are larger than those actually observed. Econometric analysis of observed flow data revealed that Rockies flows were approximately 10% larger on weekends than on weekdays during the injection season. The magnitude of winter weekend shifts was similar but of opposite sign. However, according to the simulation model, the optimal shifts are much more pronounced. Even if such large shifts were optimal to take advantage of price differentials and intraweek arbitrage opportunities, it is unlikely that they would be tolerable from an operational perspective.

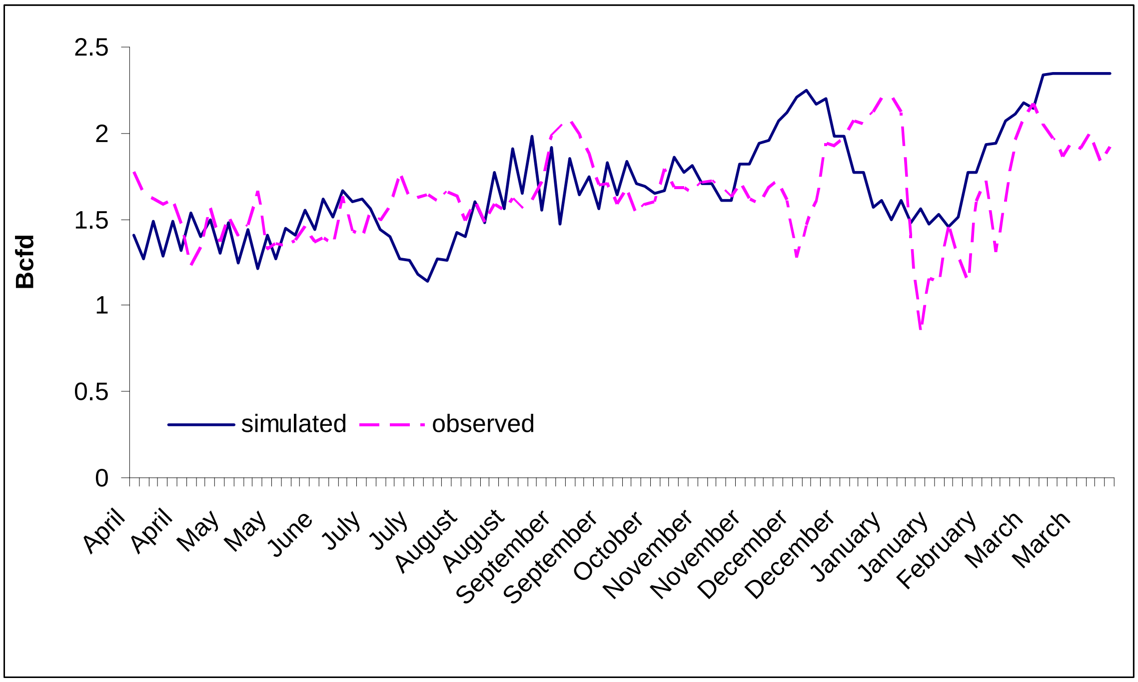


Figure 17: Observed versus Simulated San Juan Flows

Seasonality in flows originating in the San Juan basin is stronger in the simulated than in the observed series. The average summer flow is 1.53 Bcfd in the model versus 1.58 Bcfd in historical data while the average winter flows are 1.92 and 1.73 Bcfd respectively. As for the weekly cycles, simulated weekend shifts are similar to observed shifts during the injection season but smaller October through March.

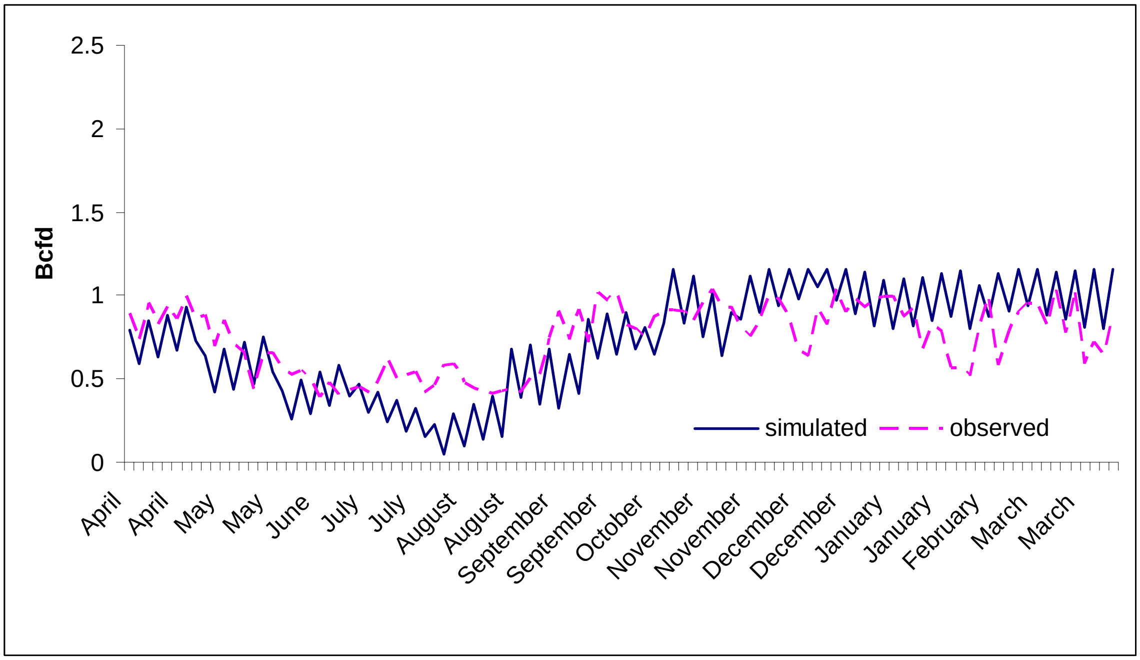


Figure 18: Observed versus Simulated Permian Flows

Permian gas is a more attractive source of gas for California during the winter than during the injection season. Such a pattern is a result of the relative seasonality in California demand versus other market centers competing for Permian gas. Arizona and New Mexico are relatively hotter than California in the summer and have no underground storage. Thus, during the summer months, the demand peak in those regions will be larger than in California, making the Permian gas a relatively expensive and unattractive supply source for California. Both the observed and simulated flow profiles display a jump in gas volume from this basin in August. Simulated flows April through August are smaller than those observed, resulting in a slightly more pronounced seasonal cycle than the actual one.

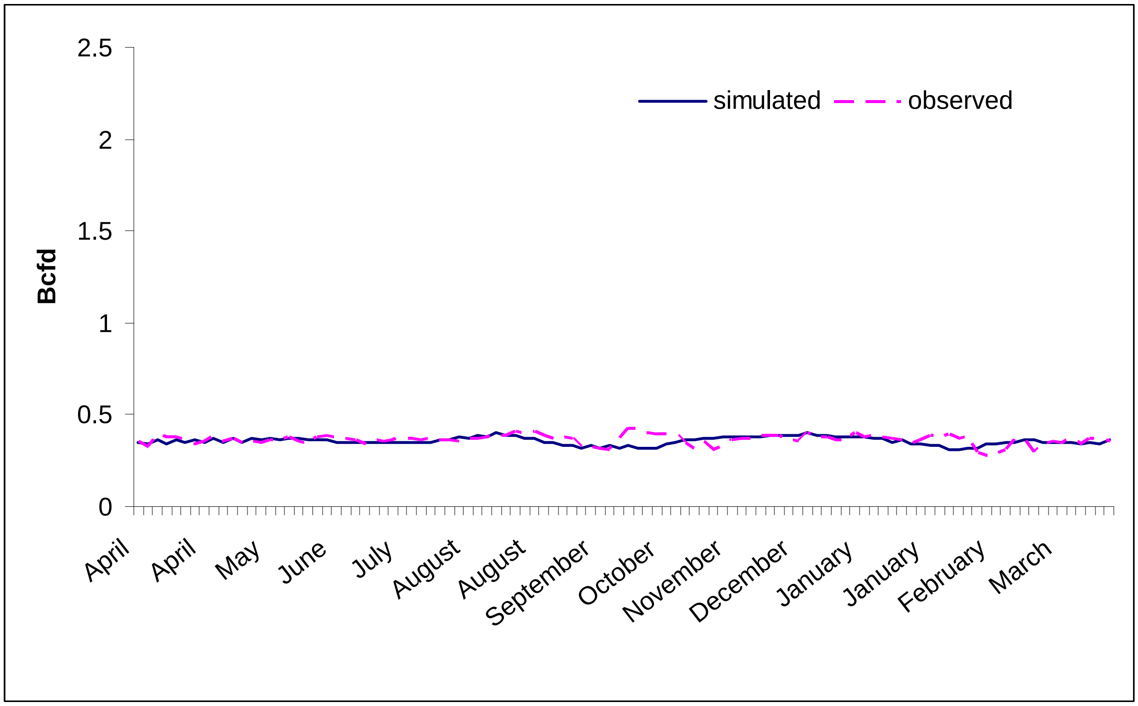


Figure 19: Observed versus Simulated In-State Production

In-state production is assumed to be base-load gas for California. This gas has no alternative destinations and is produced at a more or less steady level throughout the year. Thus, no weekend shifters were inputted in the model for domestic production. Consequently, the simulated profile is steady. The marked seasonality observed for the other gas sources has more to do with demand fluctuations in competing market centers than with fluctuations in production levels.

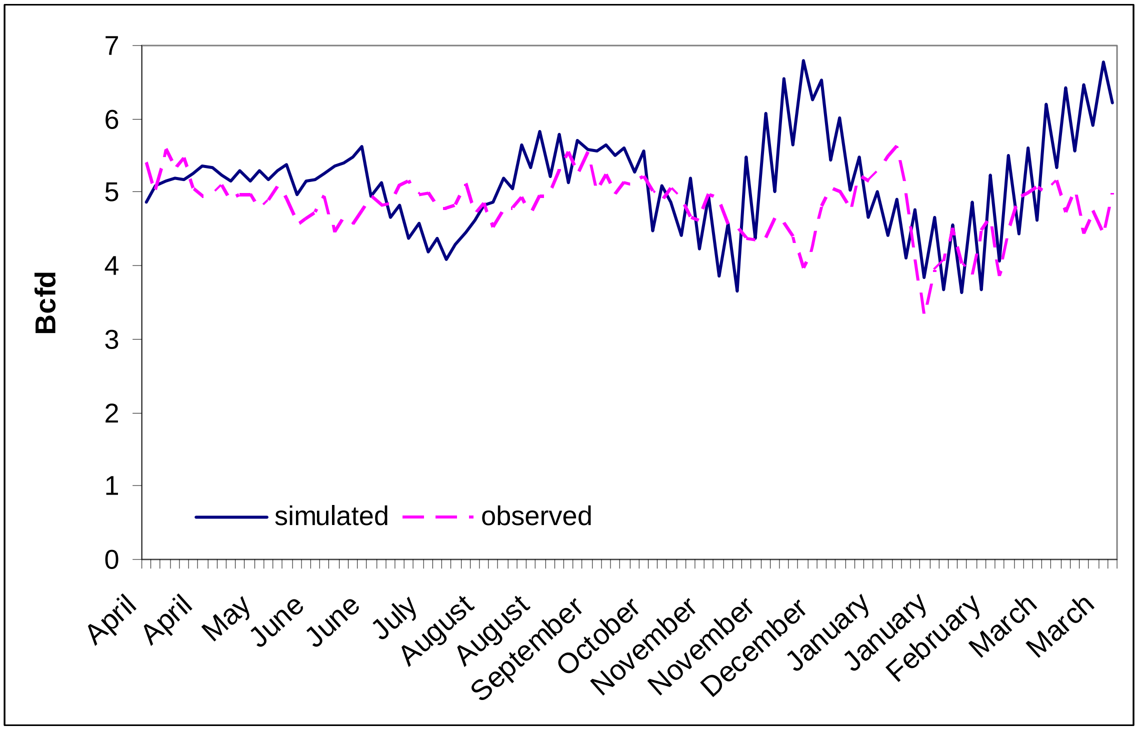


Figure 20: Observed versus Simulated Total Flows into California

Figure 20 displays total simulated and observed flows into California for the base-case period. According to the model, the optimal gas volumes – optimal to satisfy demand requirements in the most efficient way – are somewhat larger than the observed ones for most of the year. To some extent, the seasonal profiles of each different source offset each other so that the total average is steadier than the individual series.

3.2 Sendouts

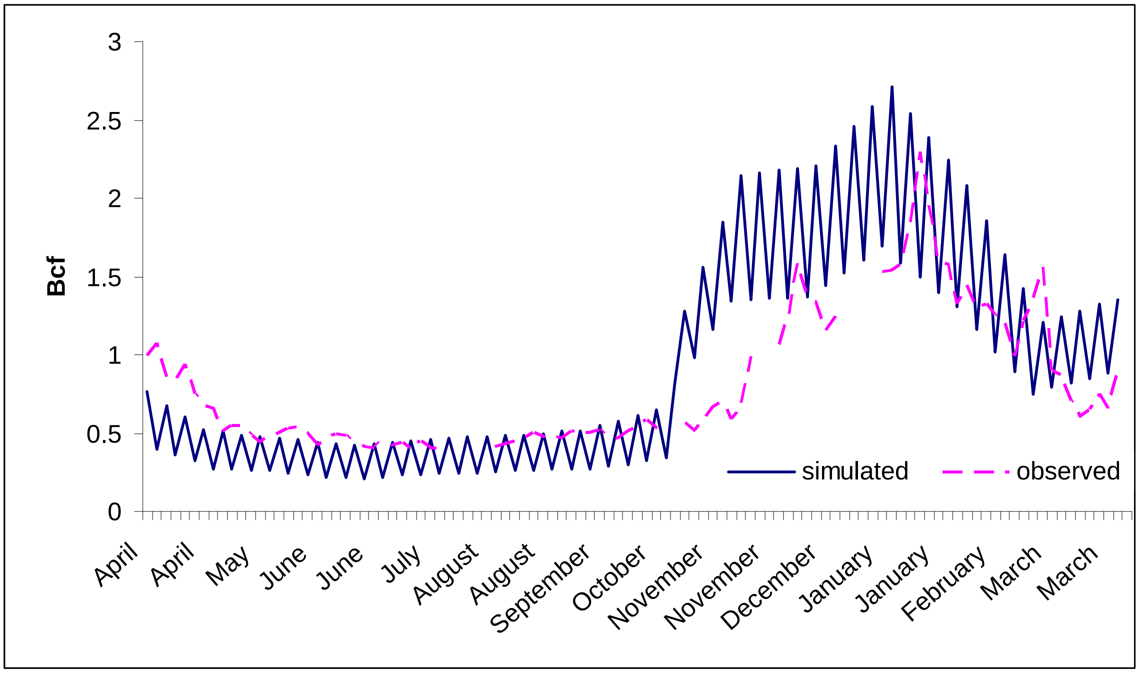


Figure 21: Observed versus Simulated Sendouts to PG&E Core Customers

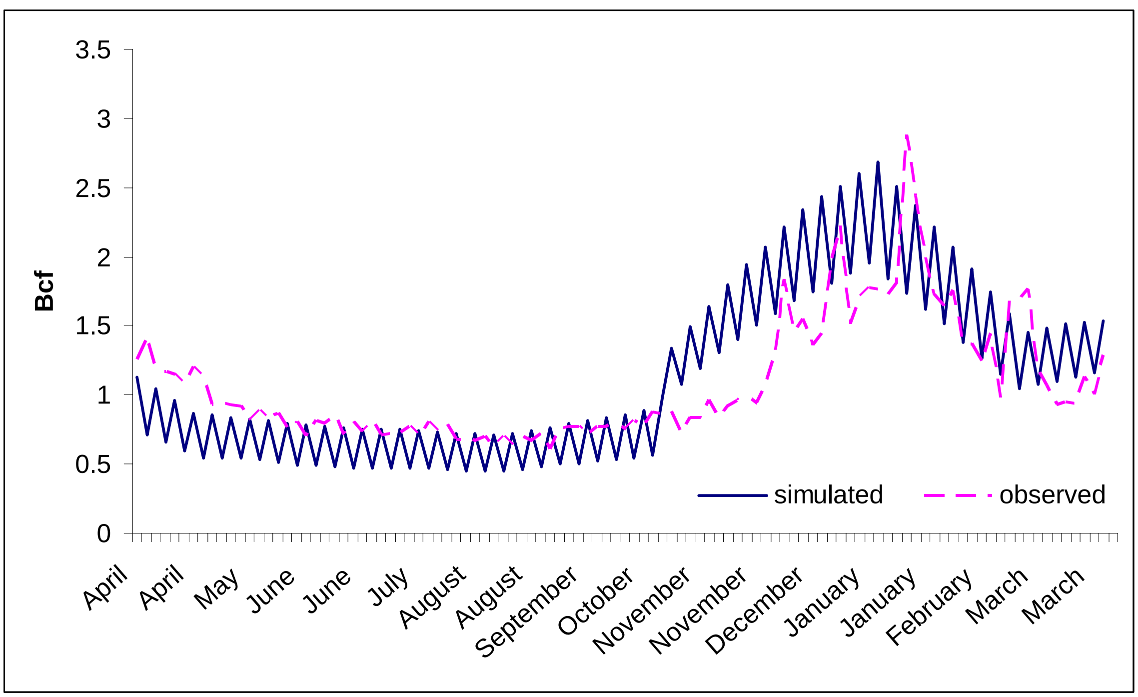


Figure 22: Observed versus Simulated Sendouts to SoCal Gas Core Customers

The seasonal profiles of core loads in Northern and Southern California are well captured by the simulation results, although the actual winter season starts later than the simulated one. The actual weekly cycles are not as "clean" and steady as predicted according to the weekend demand shifters inputted in the model.[11]

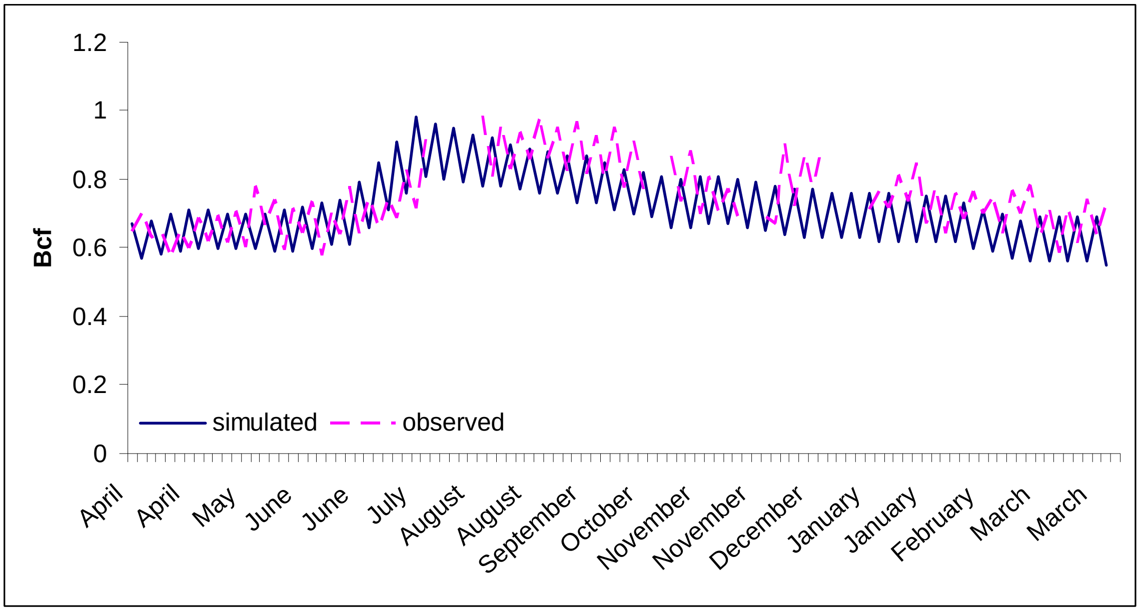


Figure 23: Observed versus Simulated Sendouts to PG&E Noncore Customers

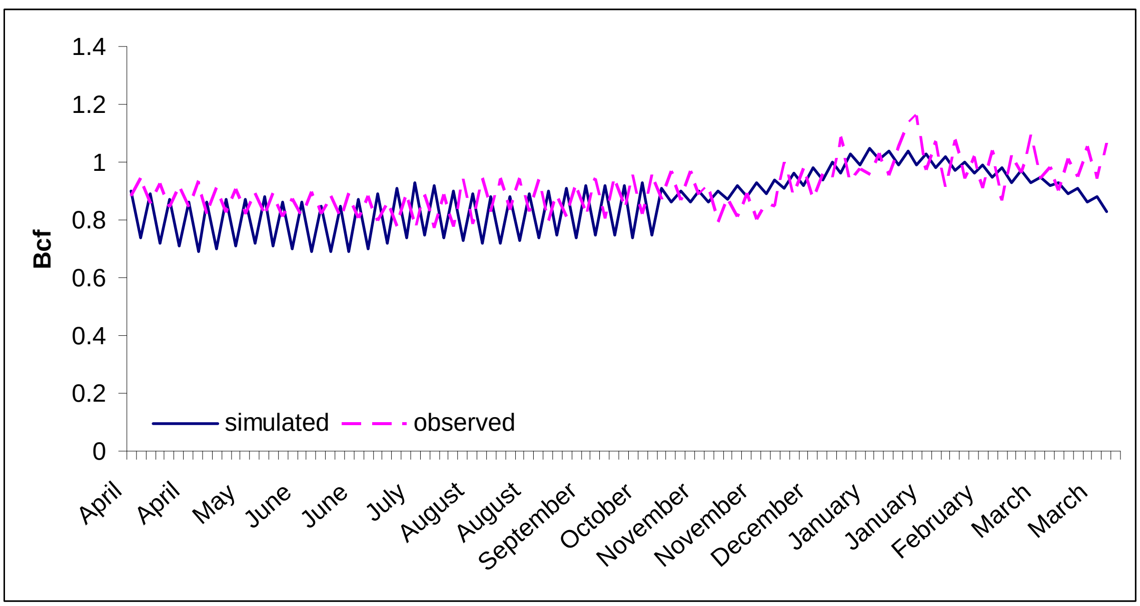


Figure 24: Observed versus Simulated Sendouts to SoCal Gas Noncore Customers

[11] Discontinuities in the observed sendout profiles are due to missing data.

Industrial loads are the least seasonal. Industrial loads do display weekly cycles, because some of the industrial customers served by PG&E and SoCal Gas do not operate on weekends. The size of the simulated weekly shifts in Northern California is similar to the observed ones – weekend industrial loads are about 10% lower than Monday through Friday. For SoCal Gas, the simulated weekend reduction in industrial load is more pronounced during the first half of the year.

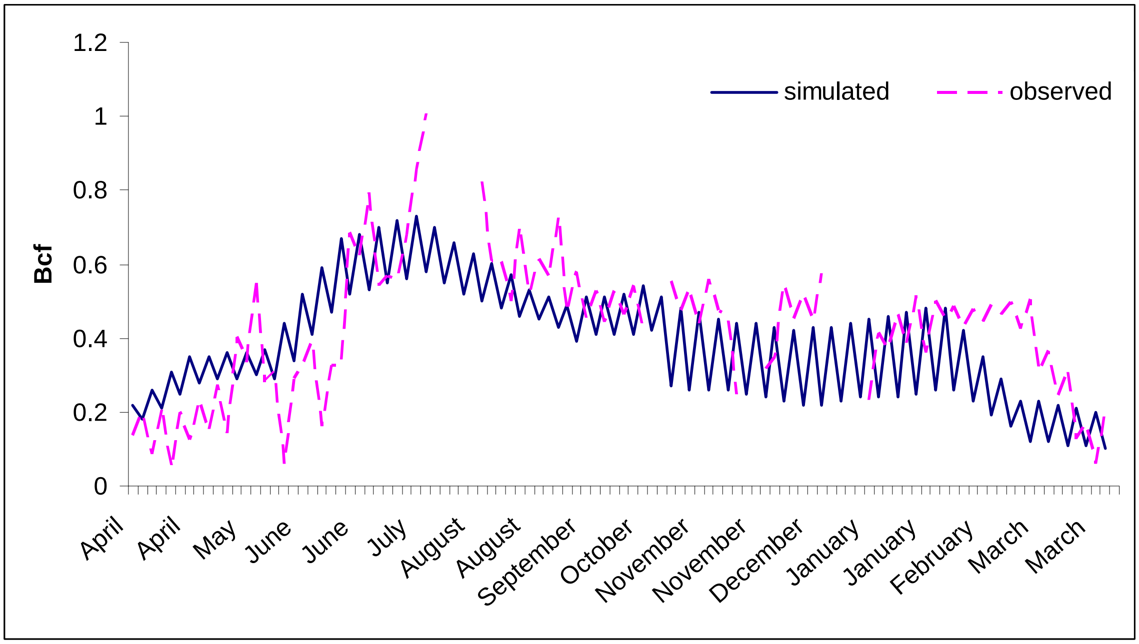


Figure 25: Observed versus Simulated Sendouts to PG&E Electricity Generators

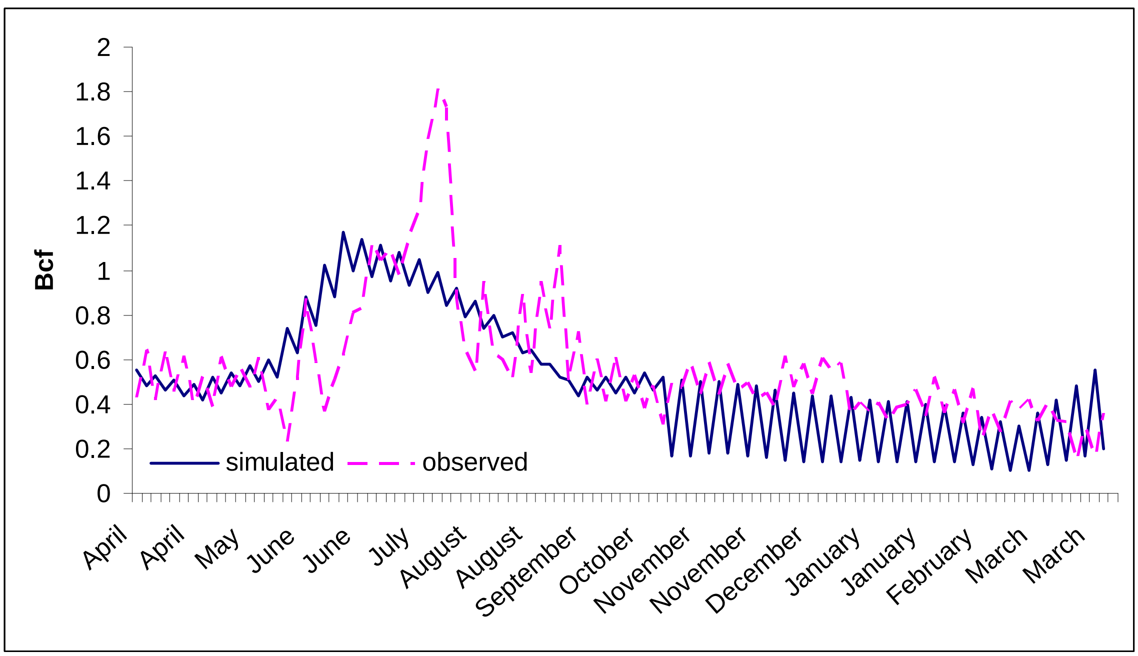


Figure 26: Observed versus Simulated Sendouts to SoCal Gas Electricity Generators

The model captures well the seasonal shape of electricity generation loads. The optimal sendouts to electricity generators are larger than the observed sendouts in the first trimester and lower January through March. Demand requirements by electricity generators shifted considerably from weekday to weekend in several occasions, particularly during the summer months. Because the model is based on a stylized representation of the supply and demand seasonal and weekly patterns, those large shifts, mostly caused by weather events, are not replicated by the simulated results.

3.3 Citygate Prices

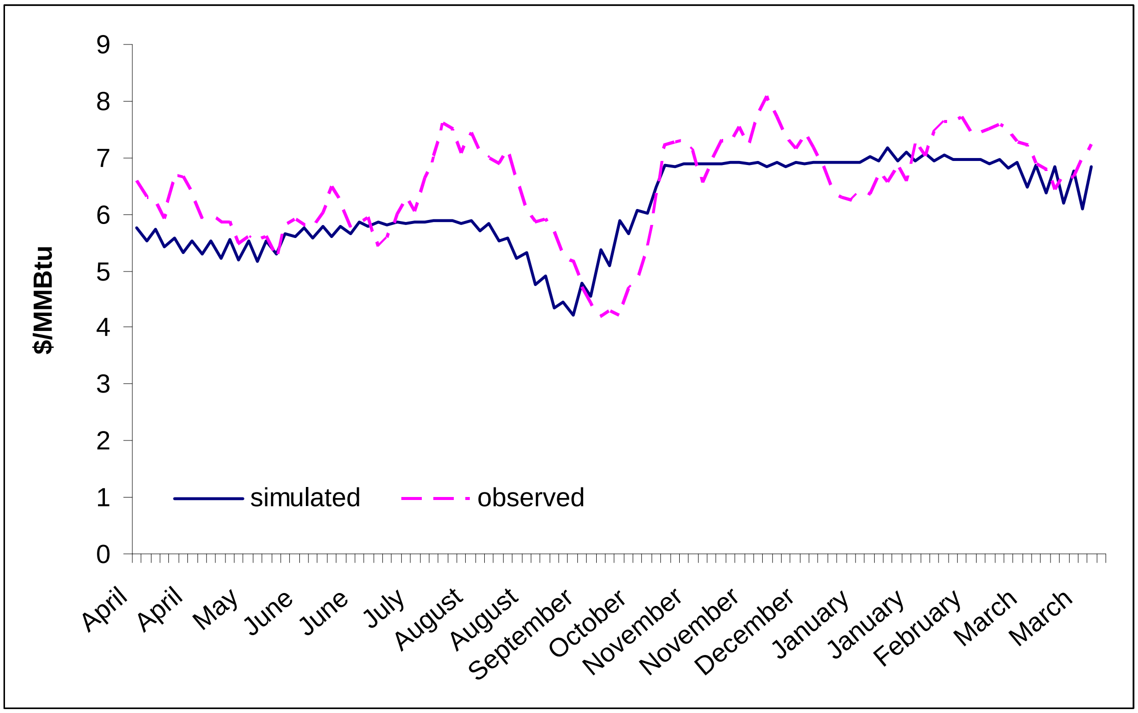


Figure 27: Observed versus Simulated PG&E Citygate Spot Price

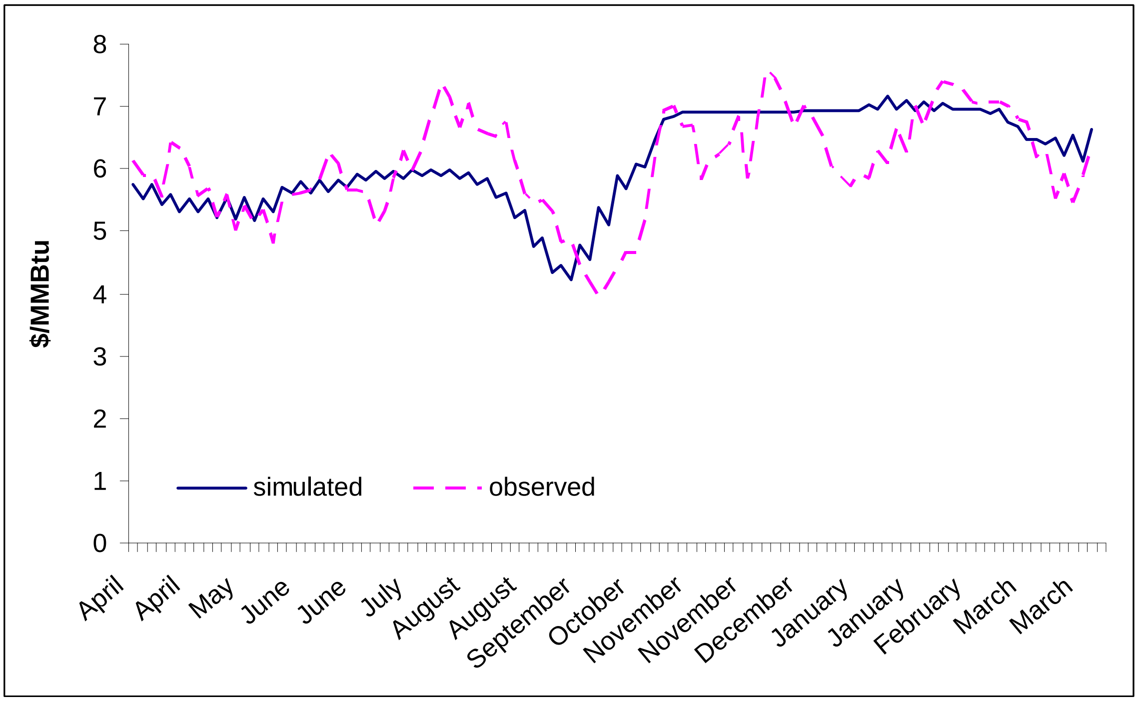


Figure 28: Observed versus Simulated SoCal-Border Average Spot Price

In Figures 27 and 28, the simulated profiles for price are shown next to the observed price series for the two most active pricing points in California. Simulated price levels are close to the observed average prices on a seasonal basis. The magnitude of the price jump that takes place in October 2006 is well captured by the model. Intra-seasonal price fluctuations are larger in the observed than in the simulated series, however. Observed price peaks are often the result of random shocks due to weather events or operational disruptions, while the simulation results stem from anticipated supply and demand patterns.

The observed price differential between Southern and Northern California was positive for most of the injection season and negative for most of the winter. The sign of the simulated differential also switches between seasons but the number of winter periods in which the differential is negative is smaller than what was actually observed. Figure 29 shows the evolution of the intrastate price differential (PG&E Citygate – Southern California border average).

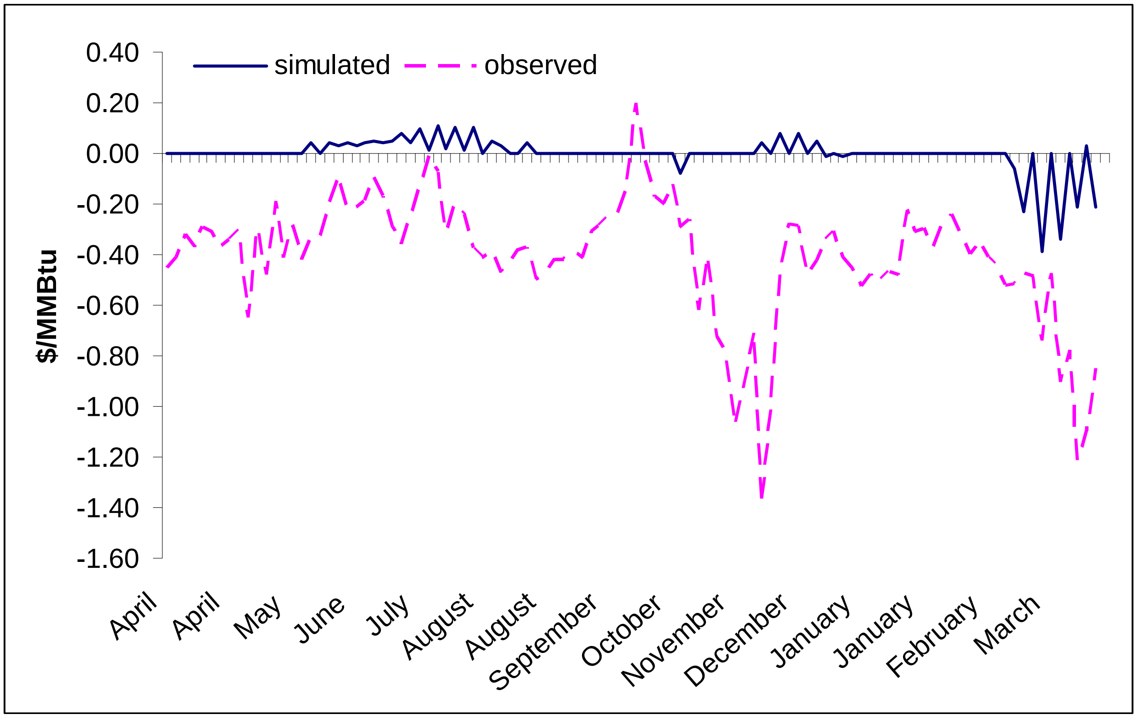


Figure 29: Observed versus Simulated Intrastate Price Differential

Given the assumptions about transportation cost of gas between Northern and Southern California, the price differential should be no more than 6-7 cents per million British thermal units (c/MMBtu) in absolute value unless capacity constraints are binding. By construction, the nonlinear program exhausts available spatial arbitrage opportunities and brings the spatial price differential inside that interval. Moreover, switches in the sign of the price differential correspond to switches in the direction of gas. During those periods in which the price differential is positive, SoCal Gas receives gas from the PG&E system, while at the end of the year, prices at the Southern California border are higher than at the PG&E Citygate and gas flows from south to north. On March weekends, intrastate pipeline capacity is fully utilized.

The observed price differential was negative all year except for one period at the end of September. Even so, gas flowed continuously in the north-to-south direction. Conversations with utility managers explained this counterintuitive flow pattern. Gas crossing at the Wheeler Ridge or Kramer Junction interconnects north to south is, in fact, Canadian gas contracted by customers in Southern California. Therefore, the relevant price differential would be one between NOVA AECO and Southern California, which is consistent with gas flowing in the observed direction. In the model, the only allowed route for Canadian gas is to the PG&E system. Canadian gas only arrives to the SoCal Gas system through the intrastate PG&E-SoCal Gas route, hence the divergence between simulated and observed results for this variable.

3.4 Net Injection and Load Factors in Underground Facilities

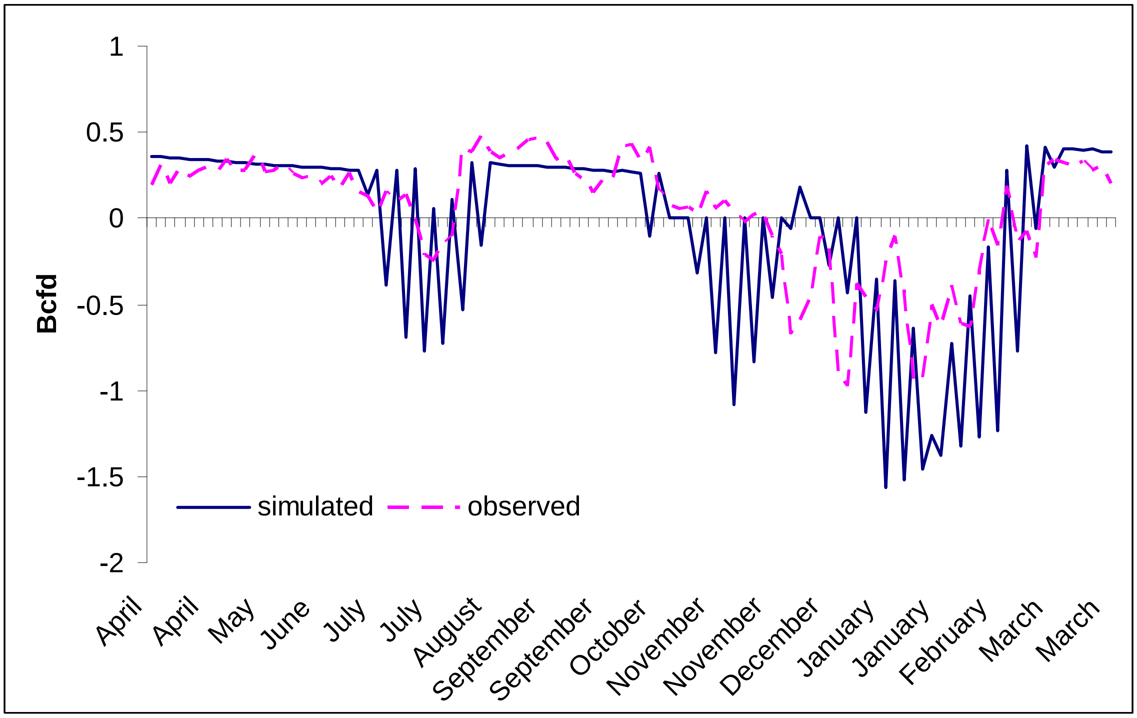


Figure 30: Observed versus Simulated Net Injection into PG&E Storage Facilities

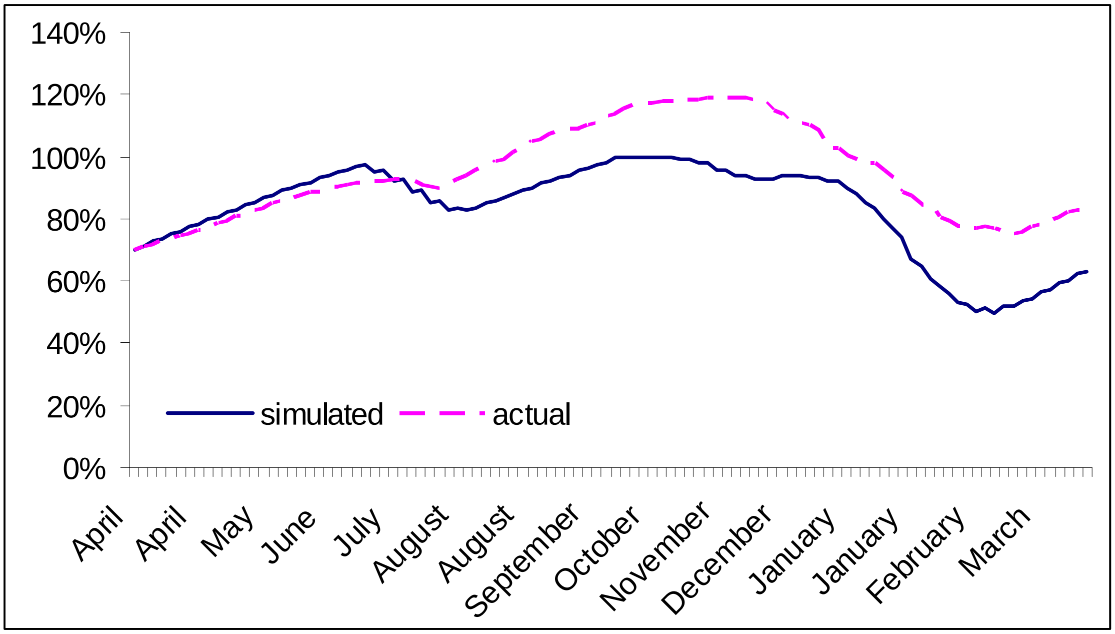


Figure 31: Observed versus Simulated Load Factors for PG&E Storage Facilities

Figure 30 displays a simulated net injection profile for PG&E-owned facilities that follows the observed pattern closely. The only failure of the calibration has to do with the magnitude of weekly cycles, especially during the withdrawal season. The model incorporates a linear relationship between injection/withdrawal rate and inventory level. However, it does not impose any restrictions on the size of the changes in flow rates as long as they are within the feasible interval. Storage operators face additional engineering constraints, which go beyond the level of detail pursued in this model.

Figure 31 displays the stock profiles that result from simulated and observed injection and withdrawal decisions during the base case period. The simulated profile reaches the official working gas capacity in June and September. The observed stock peak level is well above the official volume, which implies that storage capacity is to some extent flexible. The official working gas capacity figure corresponds to a comfortable pipeline pressure but higher pressures can be born if compressor horsepower allows and prices are attractive enough.

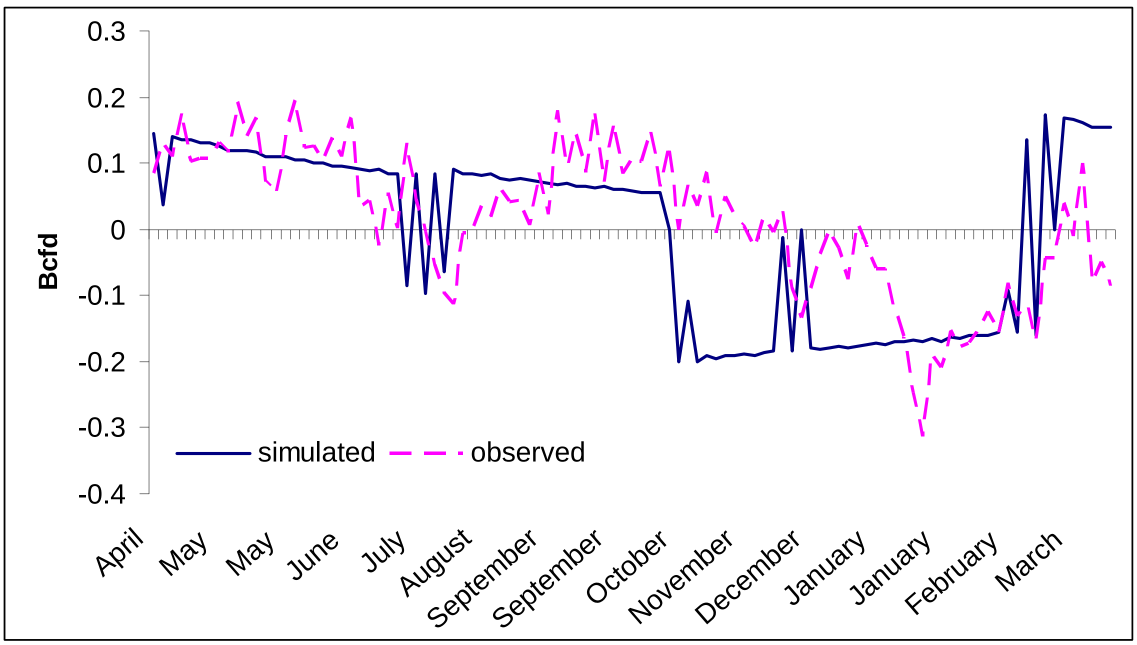


Figure 32: Observed versus Simulated Net Injection into Wild Goose

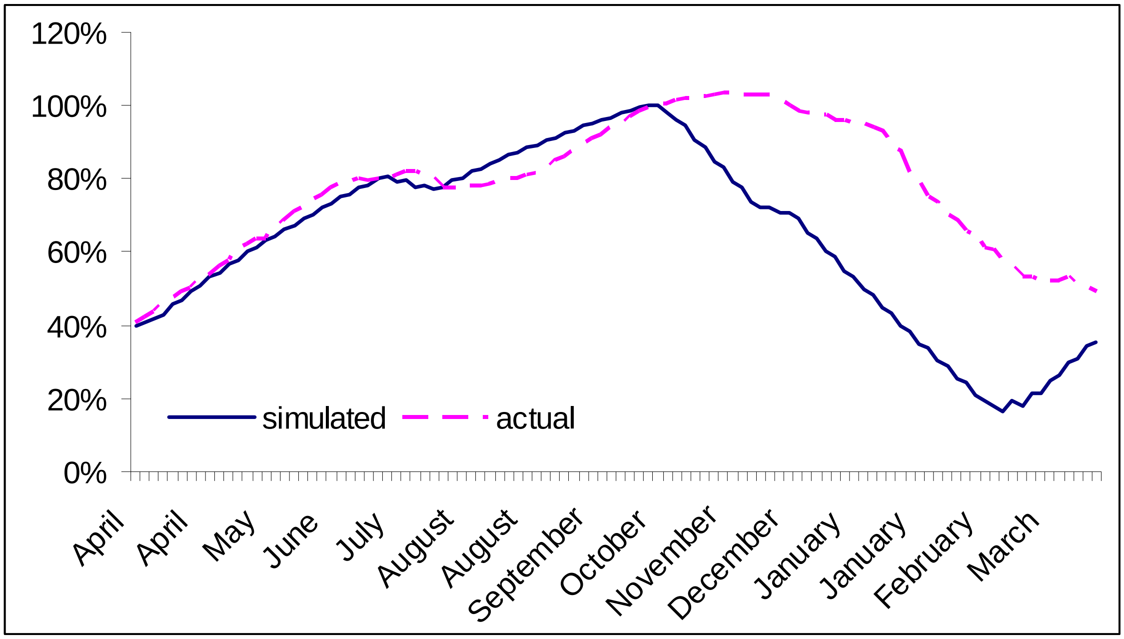


Figure 33: Observed versus Simulated Load Factors into Wild Goose

The simulated injection profile shows steady declining additions to storage April through October except for some net withdrawals in July. Actual storage behavior during those months displays more fluctuations. The steadier simulated profile is the result of a perfect foresight model where injection and withdrawal decisions for the whole year are taken on April 1 with full information about the supply and demand profiles for the following twelve months. The simulated weekly shifts for the winter season complement the weekly demand cycles. During the winter, demand is heavier on weekends and so withdrawals from storage are also larger Saturday and Sunday than the rest of the week.[12]

The simulated stock profile displayed in Figure 33 for Wild Goose follows closely the observed one April through November. Then, simulated winter withdrawals are larger and start earlier than the actual ones. The divergence can be explained because the model is solved knowing that December prices are in “backwardation” relative to November prices, a pattern that is not typical and was not expected by those holding stocks in October 2006.

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[12] Core load has the largest weight in the PG&E system and is heavier on winter weekends than on winter weekdays.

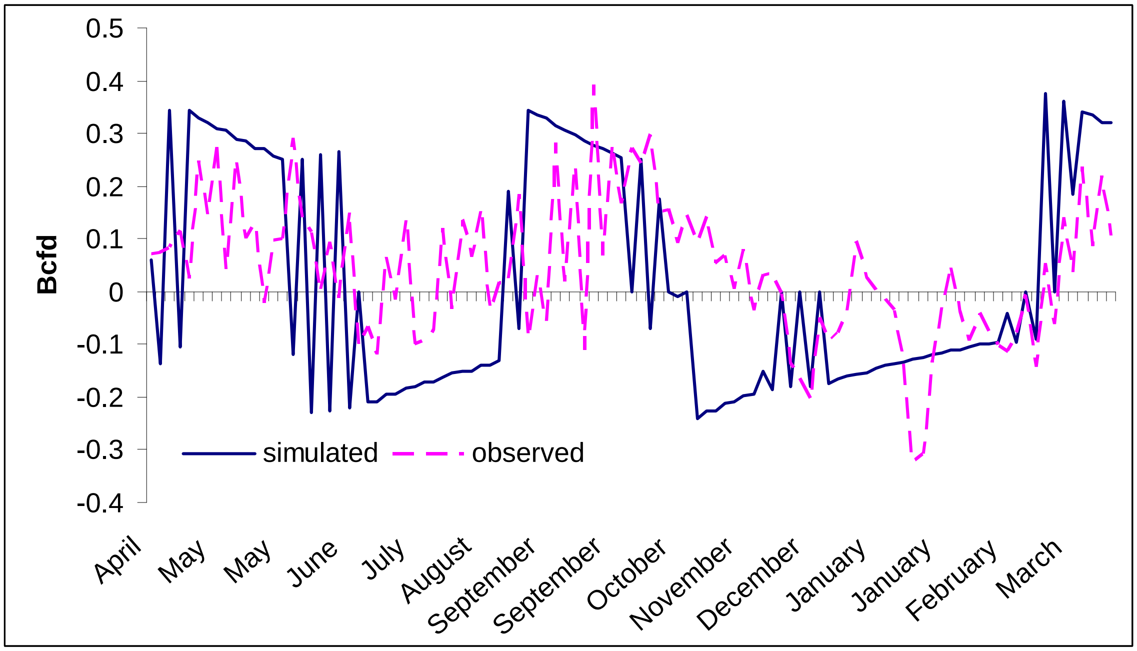

Figure 34: Observed versus Simulated Net Injection into Lodi

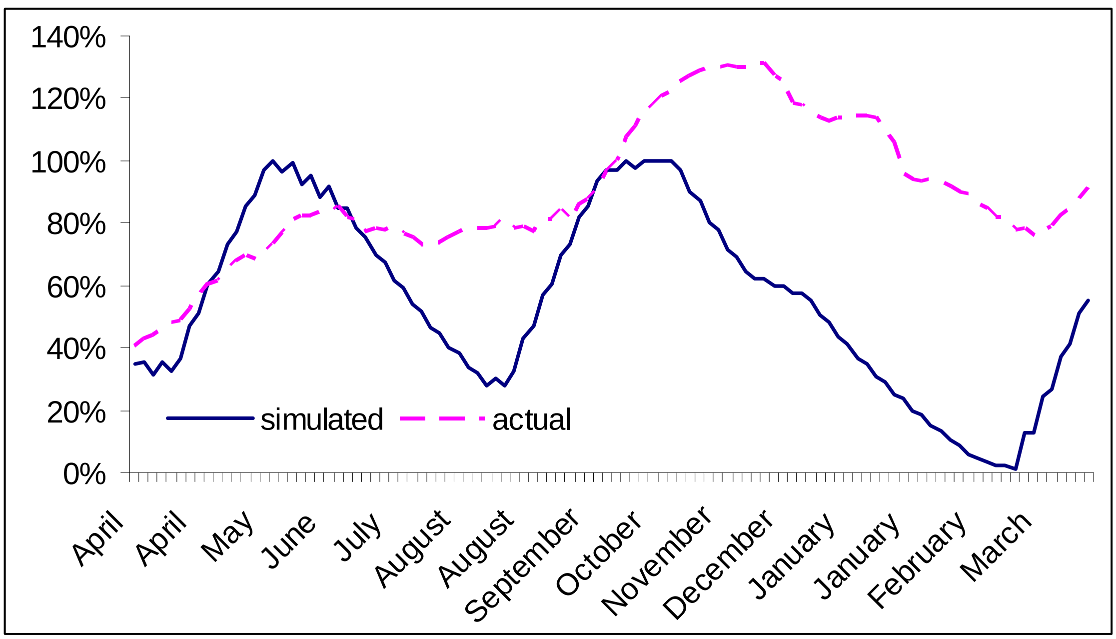

Figure 35: Observed versus Simulated Load Factors for Lodi

Lodi is the facility with the highest deliverability: Filling it up takes a little over a month and emptying out takes approximately four weeks. Therefore, all else being equal, it would be the facility of choice by those storage customers demanding more flexibility (e.g., electricity generators, active traders). Both the simulated and observed series show two and a half gas cycles at Lodi and large shifts between weekdays and weekends in each of those cycles. The first cycle is characterized by positive net injections in April and May and net withdrawals in June and July. The second cycle is characterized by positive net injections in the latter part of the official injection season. The two periods of simulated inventory accumulation stop when the stock level reaches 16 Bcf – the working gas capacity assumed in the model for this facility. Net withdrawals ensue November through January. Lastly, injections resume in the last month of the year.

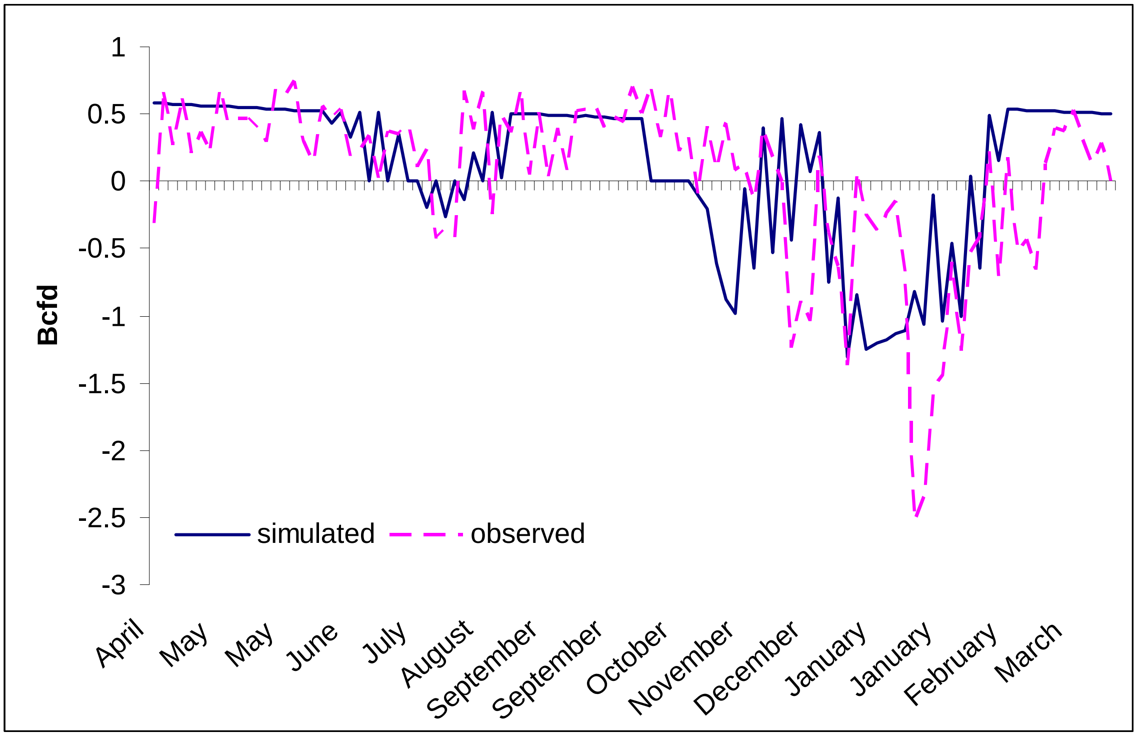

Figure 36: Observed versus Simulated Net Injection into SoCal Gas Storage Facilities

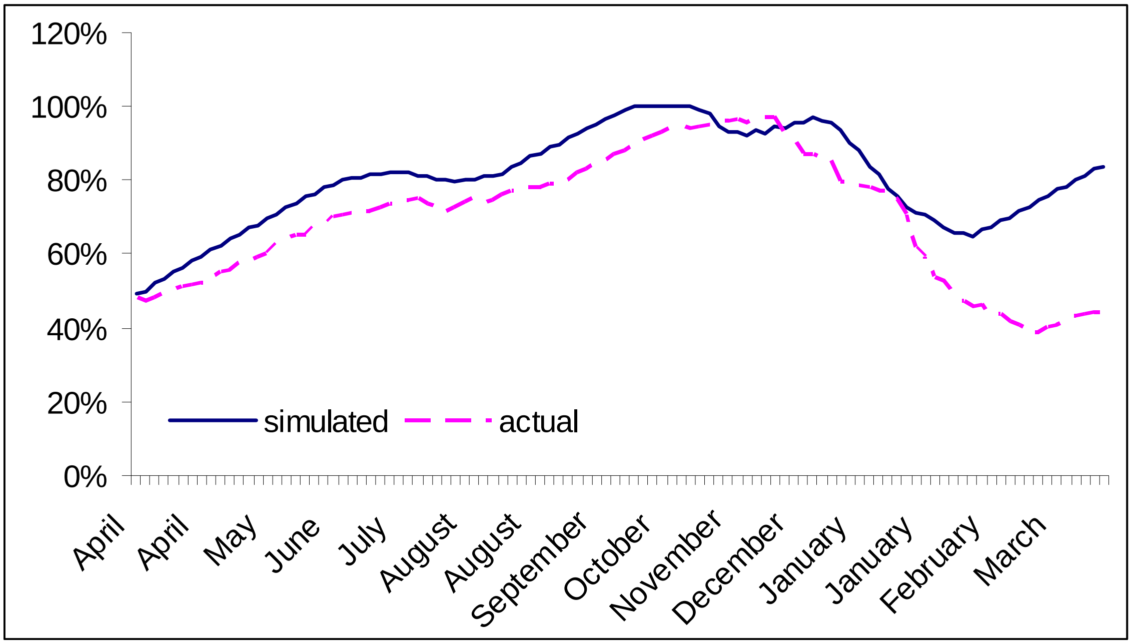

Figure 37: Observed versus Simulated Load Factors for SoCal Gas Storage Facilities

The net injection profile displayed by SoCal Gas is similar to Lodi's, although with much less pronounced a cycle during the injection season. Net injection is negative for only a couple of periods in June/July out of the whole injection season. The size of the simulated weekly shifts is in line with those actually observed for the storage facilities located in Southern California. This storage unit is the only one for which the simulated stock levels are above those actually observed during the base-case period. Customers contracting storage capacity in Southern California for the 2006/2007 season did not use all their injection rights. However, according to the forward curve inputted in the model, it would be optimal for the California natural gas market to have done so.

3.5 Linepack

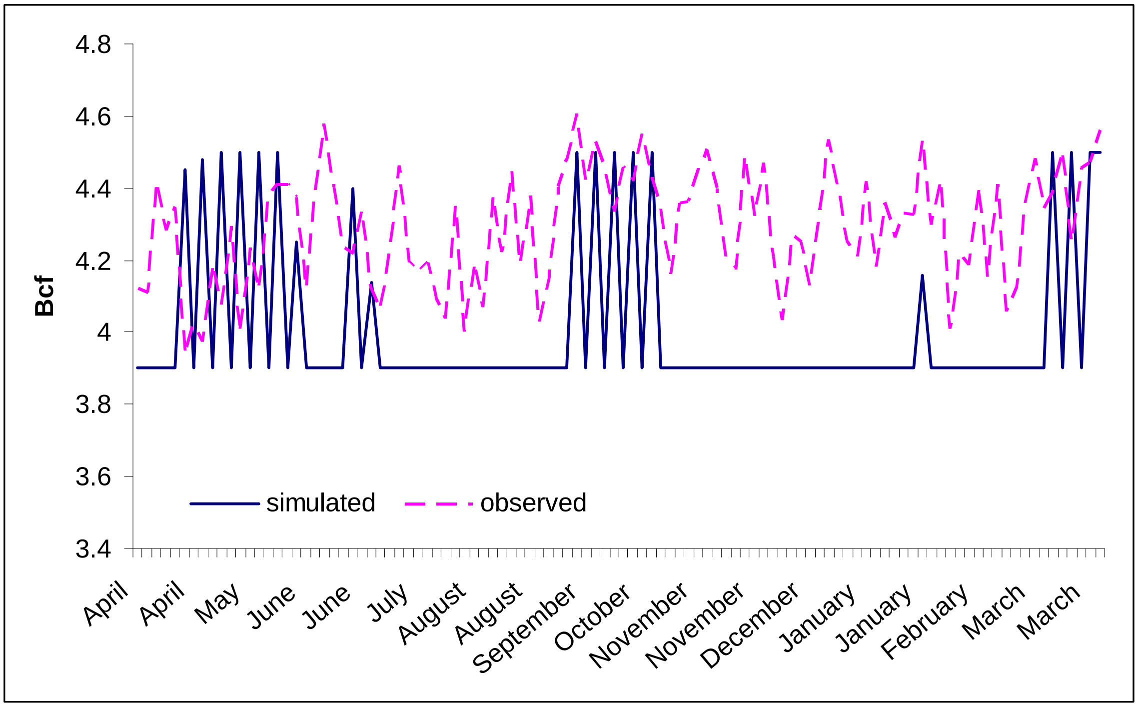

Figure 38: Observed versus Simulated PG&E Linepack Volumes

Actual linepack volume data are missing for the SoCal Gas system and the Kern River pipeline. Thus, the model's calibration for linepack can be evaluated only for the PG&E system. According to the simulated results, linepacking activity takes place only at the beginning and the end of the withdrawal season and then again in March. The rest of the time linepack is at its lower bound. In contrast, observed linepack volumes are always above the official lower bound of 3.9 Bcf. Moreover, observed net pipeline injections are never zero.

Simulated results underline the role of pipelines as a complementary buffer to that offered by underground storage. At the end of the summer, underground storage facilities are full so any positive imbalance between flows into the system and sendouts results in a linepack increase. On the other hand, negative imbalances at the end of the winter might not be buffered by close-to-empty underground storage but by linepack. Data about operational flow orders (OFO) in the PG&E system shows that the months with more OFO events during the base case period were September, October, November and March. All those events were associated with high pipeline inventory situations and correspond to periods with heavy linepacking activity. Thus, the simulated results reveal the periods in which linepacking is most used, but underestimate the degree to which pipeline inventory fluctuates the rest of the year.

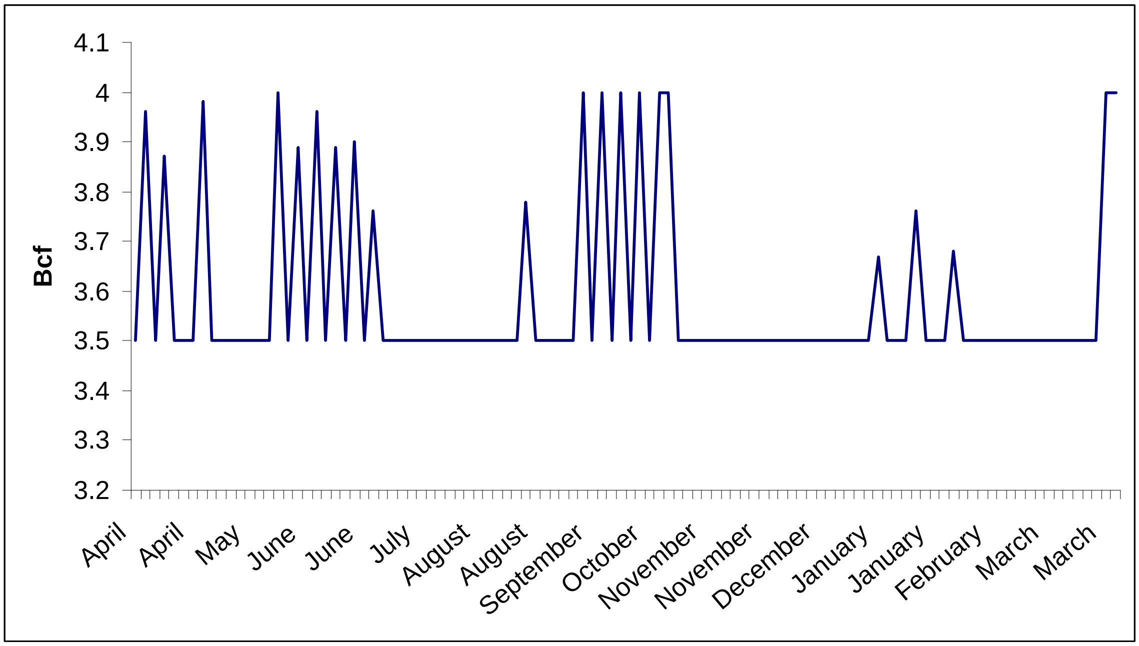

Figure 39: Simulated SoCal Gas Linepack Volumes

For the SoCal Gas system, most of the linepack fluctuations happen during the injection season. Underground storage suffices as buffer during the winter. Feasible withdrawal rates are binding constraints only on two periods versus 24 instances of fully utilized injection capacity. The assumed cost structure for the linepacking activity – increasing linepack is costly but using linepack is free as long as pipeline inventory is above the lower bound – explains why simulated volumes stay at the lower bound for prolonged stretches of time but never more than one period at the upper bound

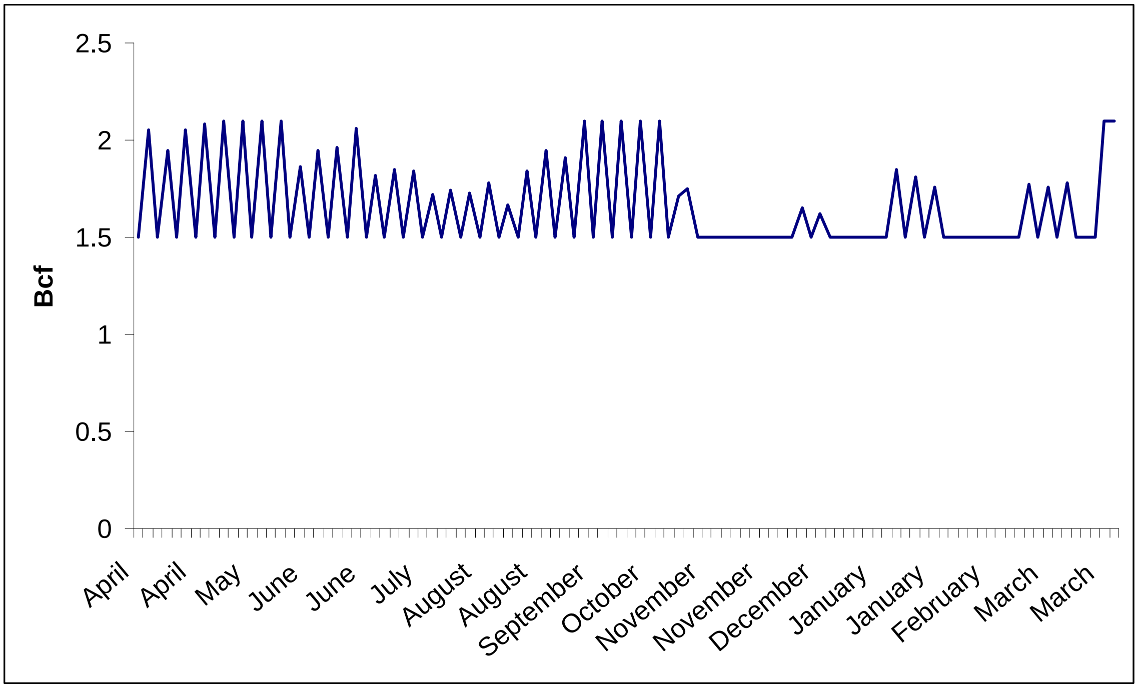

Figure 40: Simulated Kern River Linepack Volumes

Simulated linepacking activity at the Kern River pipeline displays continuous cycles during the injection season, which are more pronounced at the beginning and at the end of the season. Kern River is the only pipeline serving offsystem electricity generators whose consumption peaks during the traditional injection season. Thus, they need to continuously manage linepack to complement injection and withdrawal operations at the independent storage facilities – Wild Goose and Lodi.

3.5 Overall Calibration

All in all, the algorithm solving this nonlinear program searches for the allocation of gas that maximizes the sum of consumer plus producer surplus for California as a whole. Such an allocation results from a cost-minimizing combination of flows, withdrawals from underground deposits and linepack. Divergences between the simulated and actual mixes are attributable to several causes. The capacity, engineering and regulatory constraints in the model represent only part of the set of constraints faced by market participants. For instance, cost minimization is not the only objective that large players like utilities have in mind when making their procurement decisions. Moreover, actual flow profiles are largely influenced by long-term contracts, whose terms often are not updated with the arrival of new commodity price information. This partly explains the large divergences between model results and observed intrastate flow profile. In contrast, in the model, all information is known by all agents at the beginning of the year.

Seasonal cycles in sendouts and flows are better captured by the model than weekly cycles. Actual weekly cycles are more erratic than the simulated ones because actual changes within a week depend to a large extent on deviations in weather and operational conditions from historical averages while the simulations depict those average shifts. For similar reasons, the model replicates underground storage behavior better than linepacking. Storage decisions respond to a large extent to seasonal planning according to forward curves while linepack fluctuations result from short-term imbalances, which a perfect foresight model does not include.

Shadow values on capacity constraints reveal that additional storage capacity would be more valuable in northern than Southern California, while the opposite is true for additional pipeline capacity. The value of those two asset types is deeply interrelated. Relatively more abundant transmission capacity into the PG&E system than in the south facilitates storage capacity being filled up and enhances the value of additional underground deposits. In contrast, more storage capacity in Southern California would not be useful unless additions to pipelines ensured the feasibility of additional gas injections and withdrawals.

CHAPTER 4:
Sensitivity Analysis on Key Parameters

Assessing the sensitivity of the base-case solution to the assumed parameter values is a complementary task to model calibration. Parameters often are model-specific and need to be updated for the model to keep track of developments in actual markets. Parameter values estimated econometrically based on historical data might not be representative of present and, even less, of future behavior or costs. For instance, the demand elasticity is bound to increase as mechanisms geared toward facilitating real-time response are made available to more consumers. Another example on the supply side refers to Rockies flows. In the recent past, Rockies gas often had its only outlet into westward pipelines, which prompted episodes of extremely low prices to entice more flow in that direction. However, as more infrastructure is being built to bring this gas to mid-continent markets, the availability faced by California will be influenced by the relative values east and west. In both examples, elasticity values based on historical data might be underestimating actual responsiveness. In the end, fine-tuning parameters relies on a mixture of methods: models based on historical data, literature references, and a trial and error process to test the model's calibration under alternative values.

This chapter focuses on three parameters: the elasticity of demand, the discount rate and storage capacity. Small changes in each of them relative to the assumed base-case values causes very little change in the model's output. Thus, the sensitivity to the discount rate, shown in section 4.2, considers a wide range of values, some of which do not seem plausible under current market conditions but are useful to stress-test the model. For the elasticity and storage capacity, more interesting experiments result when they are set to zero. These extreme cases are implausible, but ones helpful to understanding the tradeoffs within the model.

4.1 Elasticity of Demand

As explained in Chapter 2, the assumed values for elasticities of supply and demand come from a mixture of econometric estimation and trial-and-error to achieve the best calibration. Thus, the sensitivity of the model's results to these parameters was evaluated while constructing the base case. Restricting all the demand elasticities to zero is an additional exercise about the sensitivity to this parameter. Testing the performance of the California pipeline and storage network under rigid load requirements provides a useful benchmark. Comparing the results from the base case to those from a specification with no elasticity gives an idea of the value of demand responsiveness.

Simulated results in the no-elasticity case are very similar to those from the base case. Therefore, the buffers provided by underground storage and linepacking are sufficient, when facing the base-case supply and demand curves, to meet load. The model still calibrates well to the actual consumption levels. Although the timing of flows and injections or withdrawals from underground storage or linepack varies slightly, simulated expenditures in wholesale gas over the year are larger than those in the base case by a trivial amount. Deviations in flows from each supply source relative to the base case are never larger than 2% in absolute value. Those deviations do not display a clear seasonal or weekly pattern.

The changes in underground stock levels are displayed in Figure 41. The only facility for which any sizable changes are observed during the injection season is Wild Goose. A few additional cubic feet of gas are stored in that deposit over the injection season in the inelastic case, especially in July. Given the assumed salvage value of stocks, an additional cubic feet of gas in storage in Northern California during the winter months provides more social value than its immediate consumption. For that reason, simulated inventory levels in Northern California facilities are slightly higher during the winter months in the base case. March simulated injections at Lodi are much higher in the inelastic case than in the base case but end-of-year stocks are the same. That is, the system relies more on the superior cycling capability of this facility when no demand-side response exists. For SoCal Gas-owned facilities, the scenario with inelastic demands results in winter inventory levels that are, in average, 0.03% (approximately 400 million cubic feet [MMcf]) larger than in the base case.

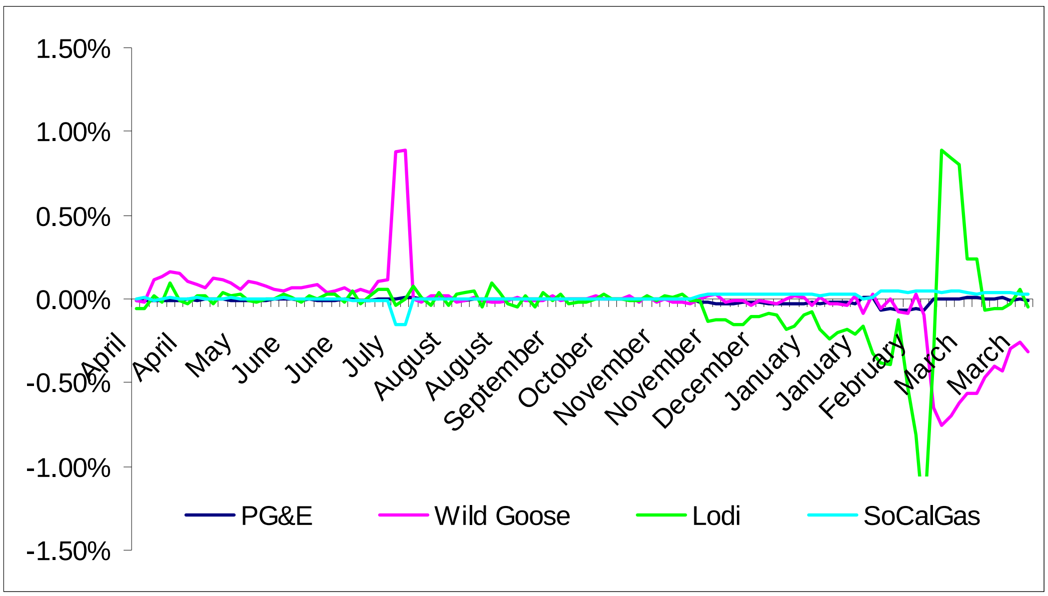

Figure 41: Percentage Changes in Flows (Inelastic Case versus Base Case)

Kern River pipeline is the only one whose linepacking profile varies in the case of inelastic load. A large fraction of flow coming through this pipeline serves electricity generators, the ones with the most responsive demand in the base case. The small changes, displayed in Figure 42, result in average lower levels of linepack. Such deviations concentrate in the summer months – the ones during which demand for electricity generation peaks.

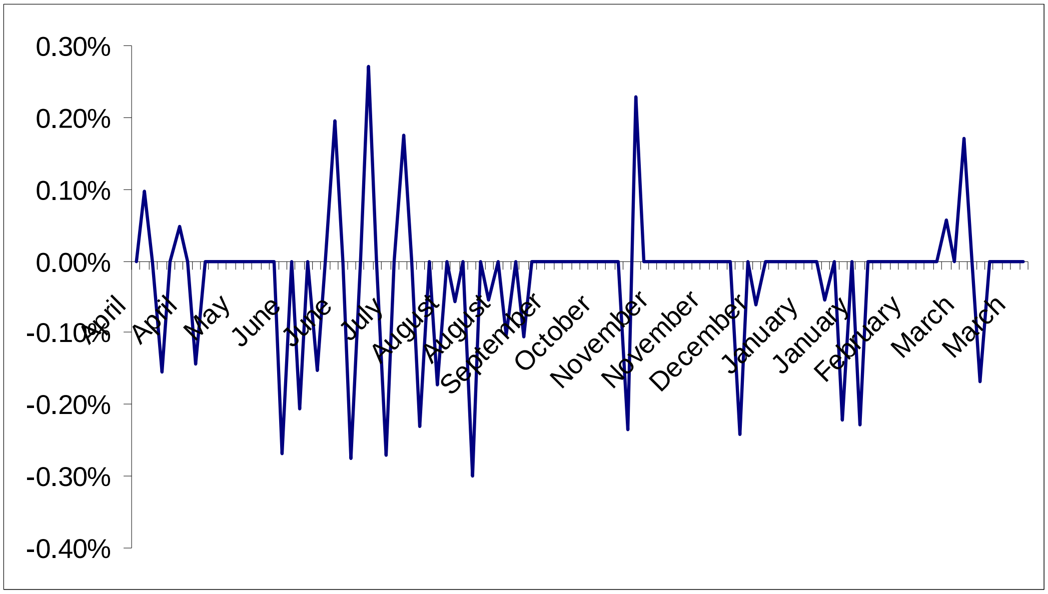

Figure 42: Simulated Percentage Changes in Kern River Linepack Profile (Inelastic Case versus Base Case)

4.2 Discount Rate

Table 8 displays the values of the annual discount rate parameter for each of the iterations for which the simulation was performed. The discount rate is an intertemporal parameter which, for a one-year model in which no investment decisions are taken, will mostly affect decisions about the timing and volume of gas injected into underground storage facilities. Because optimal storage is the focus of this research, a test of the sensitivity of the model's results to this parameter was essential.

Table 8: Discount Rate Parameters For Sensitivity Analysis

Iteration 1	1.2%
Iteration 2	3.8%
Iteration 3	6.3%
Iteration 4	8.8%
Iteration 5	11.2%

Simulated inventory levels become lower as the annual discount rate increases. This result is sensible from a theoretical perspective. The more the gas depreciates by keeping it underground rather than consuming it, the less gas should be stored. Figures 43 through 46 show the inventory profiles for iterations 1, 3 and 5. Iteration 3 is the closest to the base-case specification, which uses a 3% annual discount rate.

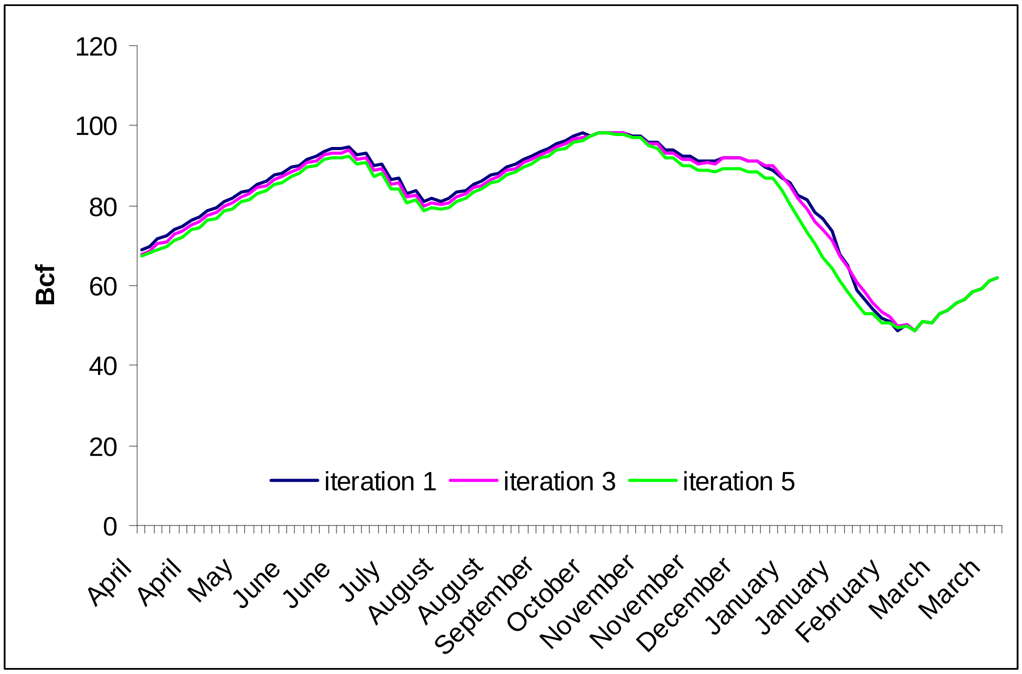

Figure 43: Simulated Inventory Profiles' Sensitivity to Discount Rate (PG&E Facilities)

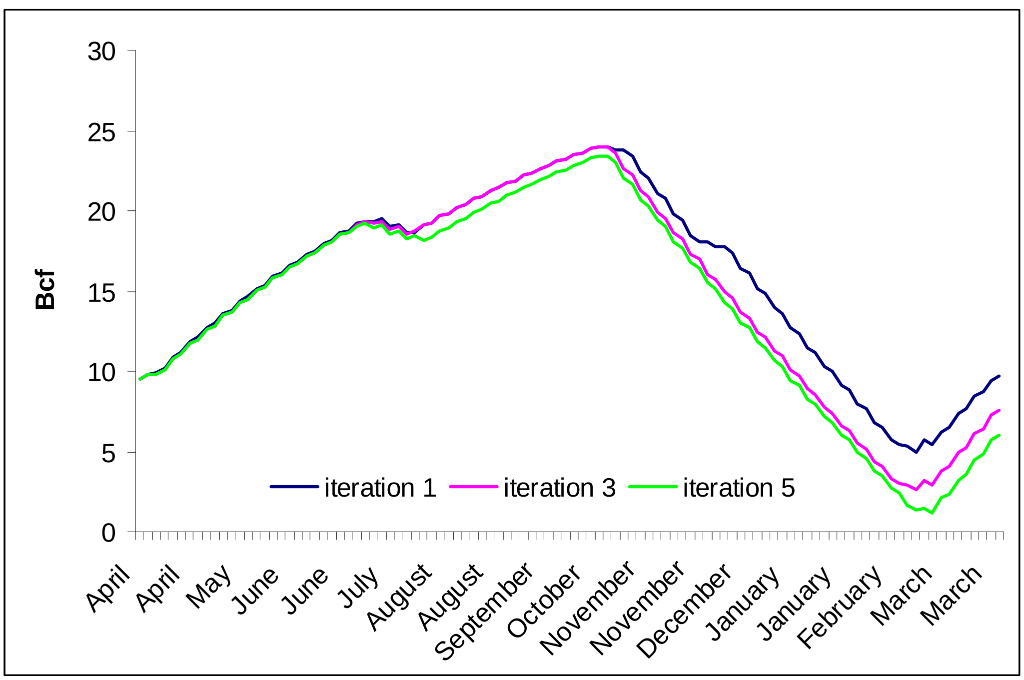

Figure 44: Simulated Inventory Profiles' Sensitivity to Discount Rate (Wild Goose)

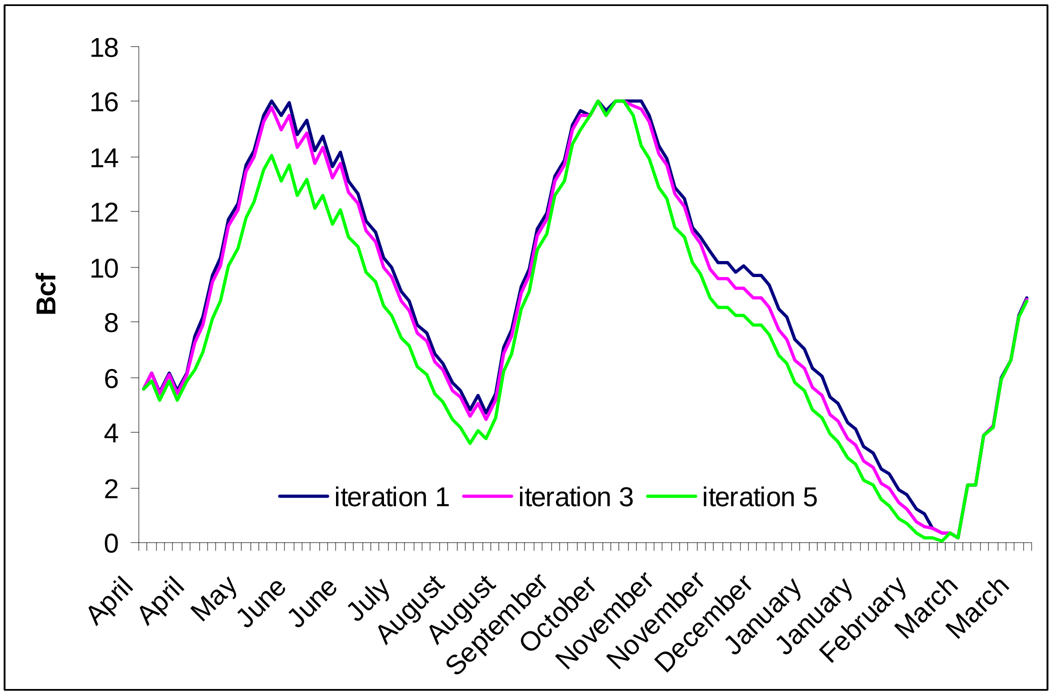

Figure 45: Simulated Inventory Profiles' Sensitivity to Discount Rate (Lodi)

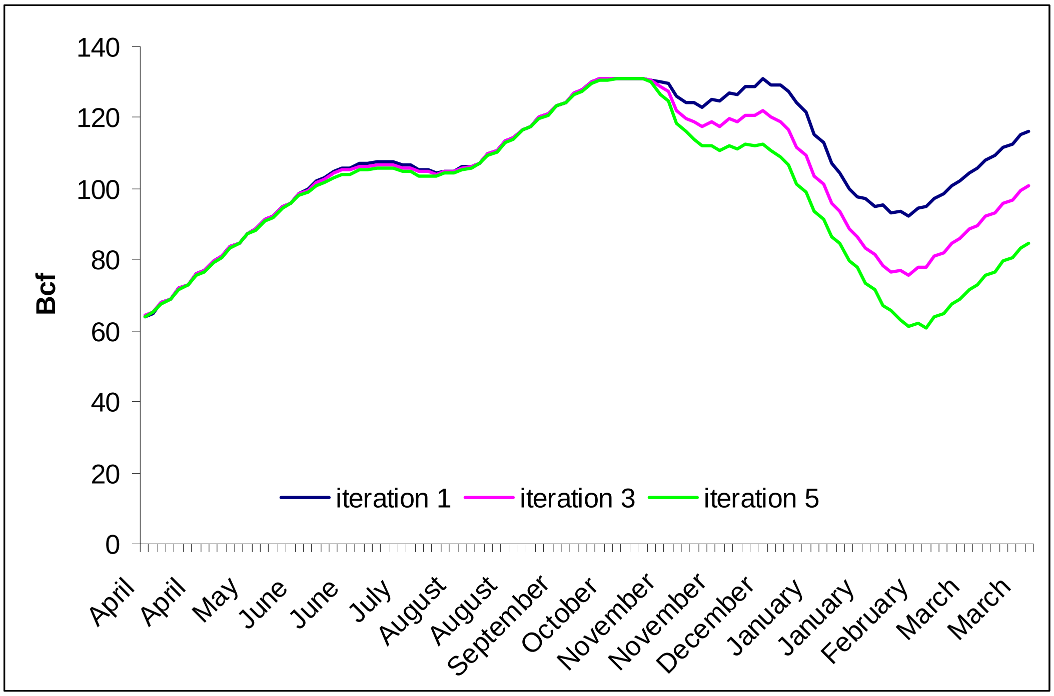

Figure 46: Simulated Inventory Profiles' Sensitivity to Discount Rate (SoCal Gas Facilities)

Figures 43 and 46 show injection profiles for utility-owned facilities are insensitive to discount rates. The inventory requirements to which these facilities are subject, combined with large days-to-fill ratios determine almost entirely their storage profiles from April to October. Facilities owned by PG&E show small variations during the winter season as well. In contrast, SoCal Gas inventory is 14% higher (36% lower) in the iteration with the lowest (highest) discount rate than in the base case.

Net injections are positive at the end of the year at all facilities for the whole range of discount rates. Once they start refilling, each of them does so at one rate which does not vary with discount rate. Winter withdrawals from November to January are sensitive to the discount rate in the four storage operations. The higher the discount rate, the lowest is the value of inventories kept underground compared to winter spot prices and the further are all facilities drawn down to cover winter demand peaks.

Simulated injections in Wild Goose and Lodi do not experience sizable deviations for discount rates of 1.2 versus 3.8%. For the highest discount rate considered, California storage has 0.6 Bcf slack capacity in Wild Goose at the end of the injection season. Moreover, Lodi would inject less gas the first two months of the year.

4.3 No Underground Storage

One way to analyze the role of underground storage on the system is precisely by simulating a scenario in which no storage capacity is available. Simulated results when working gas capacities are turned to zero shed light on the optimal supply mix were linepack the only network buffer. Figures 47-51 show simulated base-case flows versus simulated flows in the no-storage scenario for each of the producing regions.

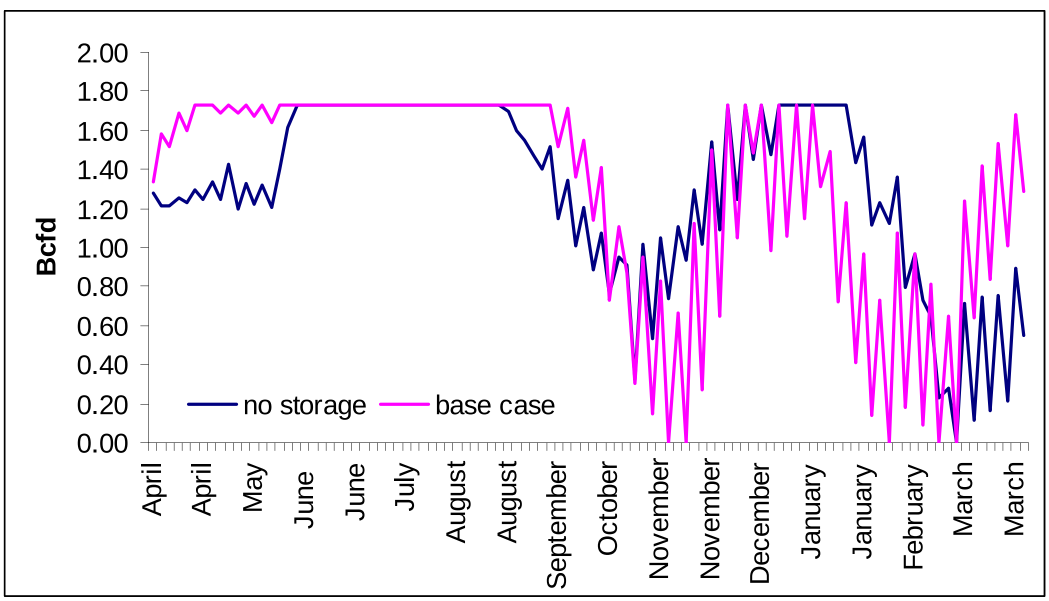

Figure 47: Simulated Canadian Flows in No-Storage Scenario versus Base Case

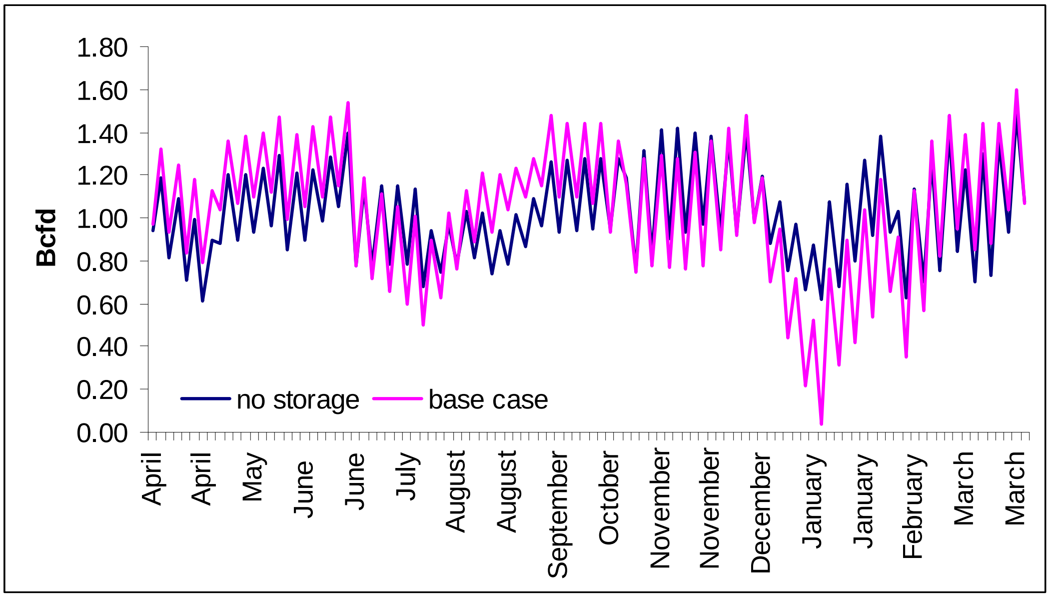

Figure 48: Simulated Rockies Flows in No-Storage Scenario versus Base Case

Simulated Canadian flows decrease by 25% in April and May. However, because no gas can be withdrawn from storage to cover summer demand peaks, receipt capacity at Malin remains fully utilized from June to August. As for the winter season, increased flows from the Western Canadian Sedimentary Basin (WCSB) would cover part of the demand which was served by storage withdrawals in the base case. Simulated flows from the Rockies display the smallest deviations with respect to the base case among all producing regions. Incoming flows through Opal are only higher than in the base case in January, the month with the highest demand.

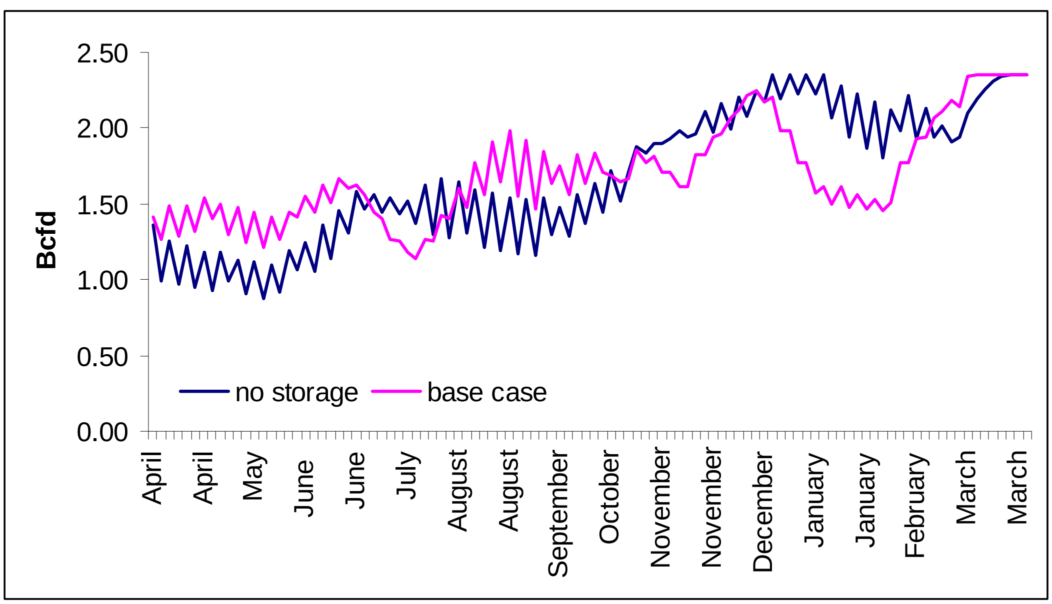

Figure 49: Simulated San Juan Flows in No-Storage Scenario versus Base Case

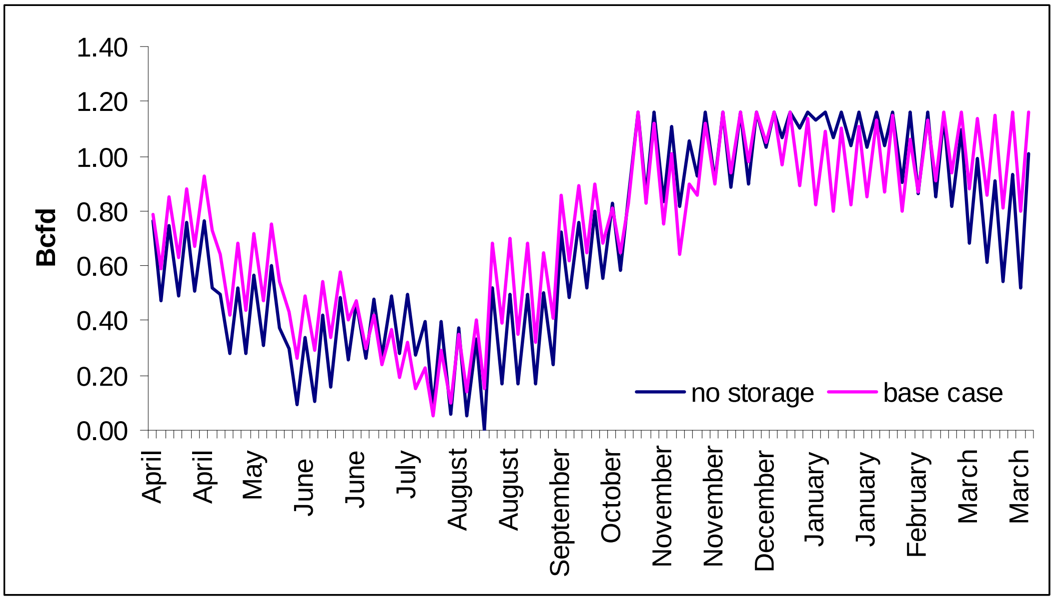

Figure 50: Simulated Permian Flows in No-Storage Scenario versus Base Case

Simulated flows from the San Juan basin deviate more from the base case than those from the Permian region. San Juan flows would be 20% lower in average during the injection season in the absence of storage, except for the month of July. In contrast, winter flows would be 26% higher in December and January weekdays and 36% higher during the weekends corresponding to those two months. End-of-year simulated flows drop again below the base case as they were directed to refill storage capacity. Permian flow deviations from the base case are of the same sign, but smaller, as those from the San Juan producing region. For instance, increase in Permian flows in December and January is 23% for weekdays and just 4% for weekends. These changes reinforce the relative seasonality and weekly patterns observed for the base case.

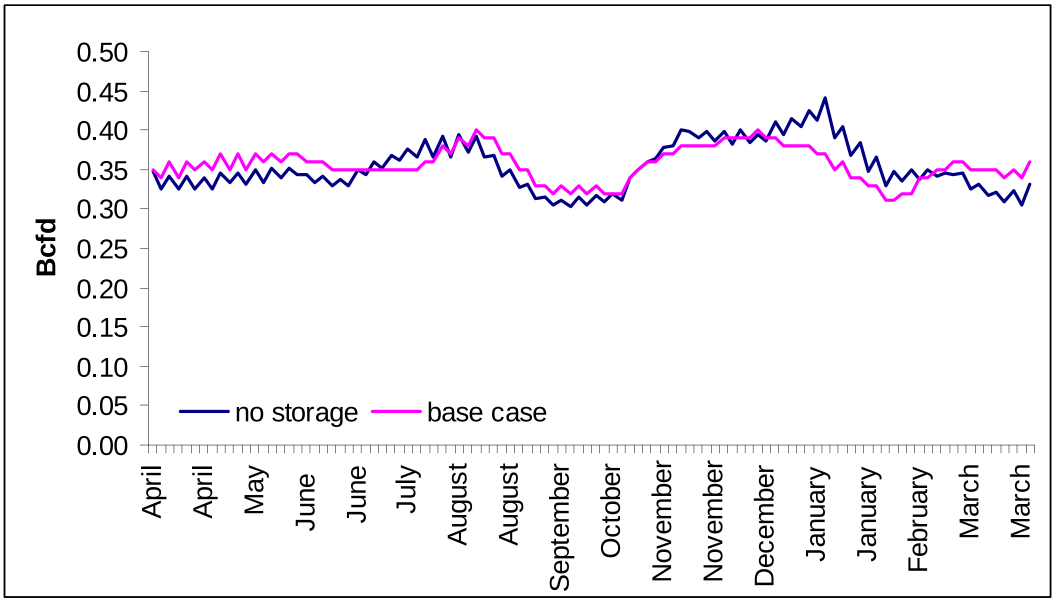

Figure 51: Simulated Domestic Production in No-Storage Scenario versus Base Case

Increases in base-load domestic production complement imported flows during peak demand periods: July in the summer and November through February in the winter. In-state production would decrease between 5 and 10% the rest of the year. Simulated total flows throughout the year are 2% lower in the case with no underground storage capacity. However, total expenditures in the commodity are only 0.4% lower ($11,344,571 in the no-storage case versus $11,384,778 in the base case). The weighted average cost of the summer gas basket is 1% lower in the no-storage case than in the base case but 0.8% higher during the winter.

Time and location of bottlenecks change when underground storage is not available to the system. The shadow value of any of the network assets is a function of the rest of the network configuration. Table 9 indicates the percentage of periods for which capacity is congested for all the routes depicted in the model both in the base case and in the no-storage case.

Table 9: Percentage of Periods with Congestion per Route and Season

	Base Case		No Storage	
	Summer	Winter	Summer	Winter
Blythe-SoCal Gas	2%	25%	2%	32%
Coastal System-SoCal Gas	93%	68%	92%	64%
Elk Hills-SoCal Gas	90%	59%	87%	41%
In-State production-PG&E	8%	36%	10%	39%
Kern River-PG&E	0%	0%	3%	16%
Kern River-SoCal Gas	3%	11%	0%	14%
Kern River-off system	8%	36%	0%	0%
Malin-PG&E	65%	14%	42%	27%
North Needles-SoCal Gas	68%	48%	50%	64%
Topock-PG&E	3%	25%	2%	20%
Topock-SoCal Gas	82%	66%	67%	66%

Under the no-storage scenario, the only receipt capacity which is not congested at any time of the year is the one held by off-system power generators in the Kern River pipeline. In the base case, in contrast, the only route that always has slack capacity is the one between Kern River pipeline and the PG&E system. Pipeline capacity in Southern California that receives domestic production or imports from the San Juan Basin through Topock have the highest percentages of congestion events for both cases. Thus, additional pipeline capacity would be relatively more useful in Southern than in Northern California.

The seasonal frequency of bottlenecks varies among routes. The pipeline routes which are more congested overall (Coastal System-SoCal Gas, Elk Hills-SoCal Gas, Malin-PG&E and Topock-SoCal Gas) all display higher percentages of congestion events during the summer than during the winter. Such a result is maintained in both cases except for gas coming into Southern California through North Needles, which switches to more intense winter congestion in the no-storage scenario.

Removal of underground storage capacity from the system has different effects in the number of bottlenecks for different routes. Those routes more prone to congestion during the injection season under the base case experience a reduction in the percentage of summer congestion periods when injection into underground deposits is not allowed. Meanwhile, winter congestion – due to more reliance on the spot market to cover peak heating demand in the absence of withdrawals from storage – increases in 6 out of the 11 routes. The clearest weekly cycle in congestion events corresponds to imports of Permian gas into Southern California. Receipt capacity at Blythe operates at full capacity most winter weekends but congestion is relieved during the business week. Changes in the supply mix ripple down to consumers. Tables 10 and 11 contain the percentage deviations in sendouts and Citygate prices with respect to (WRT) the base case per region, season and customer type.

Table 10: Percentage Deviations in Simulated Citygate Prices WRT Base Case

	Northern California	Southern California
Summer	-5%	-5%
Winter (November-February)	11%	9%
Winter (November-March)	5%	4%

Simulated Citygate prices decrease during the summer and increase during the winter, which underscores the price-smoothing function of underground storage. For March, the competition for gas between consumption and storage activities that existed in the base case disappears so that sendout prices are smaller without storage. The changes in prices showed in Table 10 trigger movements along the demand curves. According to Table 11 simulated sendouts increase for all customer groups during the injection season but decrease during the winter. According to the model's assumptions about price elasticity, electricity generators are more price-responsive than both core and industrial customers. Therefore, they take most of the extra summer sendouts but also experience the largest decrease in winter sendouts. Price responsiveness by power generators would be explained by the existence of alternative inputs that can be used to generate electricity when natural gas is scarce or too expensive.

Table 11: Percentage Deviations in Simulated Sendouts WRT Base Case

	PG&E Core	PG&E Noncore	PG&E Electricity Generation	SoCal Gas Core	SoCal Gas Noncore	SoCal Gas Electricity Generation	Offsystem Electricity Generation
Summer	3%	2%	3%	3%	2%	4%	4%
Winter	-1%	-2%	-6%	-1%	-2%	7%	-6%

Deviations with respect to the base case due to the absence of underground storage capacity are notable at the seasonal frequency. However, linepacking would still buffer the weekly fluctuations borne by the California network due to weekly demand dynamics both in-state and at competing markets. Figures 52 through 54 show the linepack profiles for the base case and the no-storage scenario.

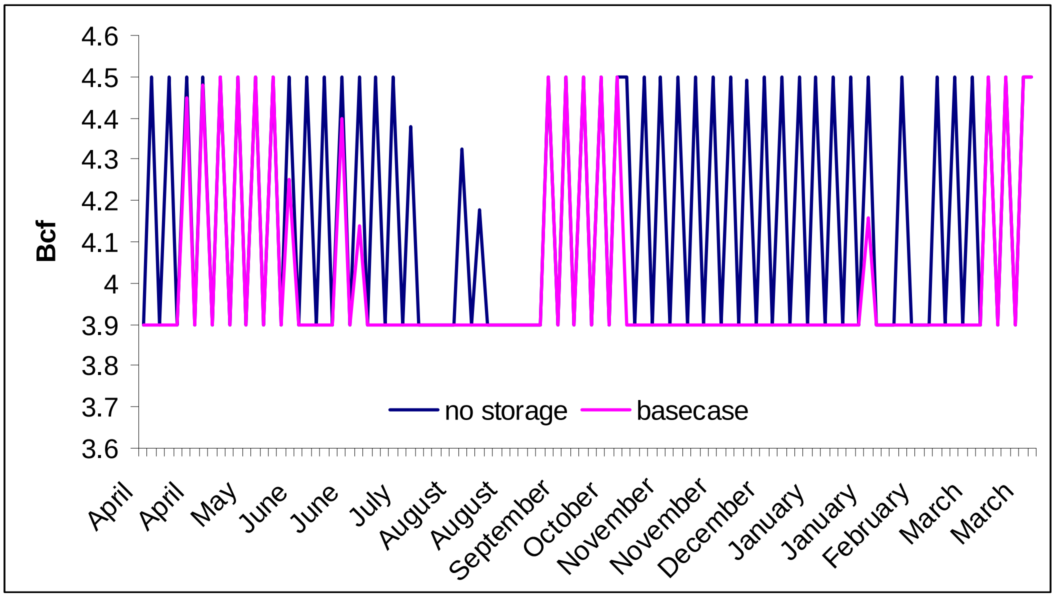

Figure 52: Simulated Linepack Profiles for No-Storage Case versus Base Case (PG&E backbone)

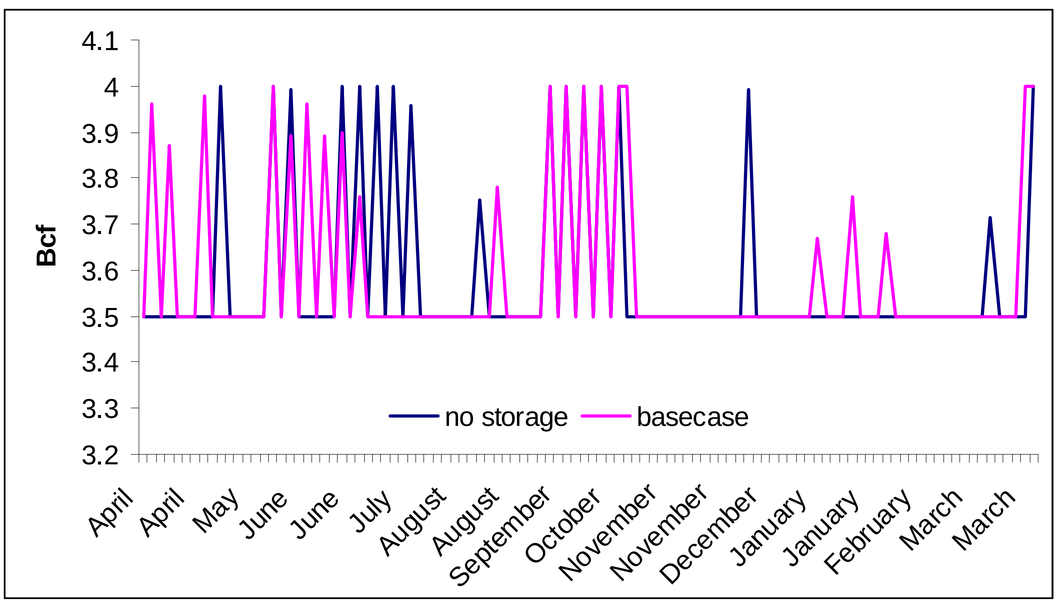

Figure 53: Simulated Linepack Profiles for No-Storage Case versus Base Case (SoCal Gas system)

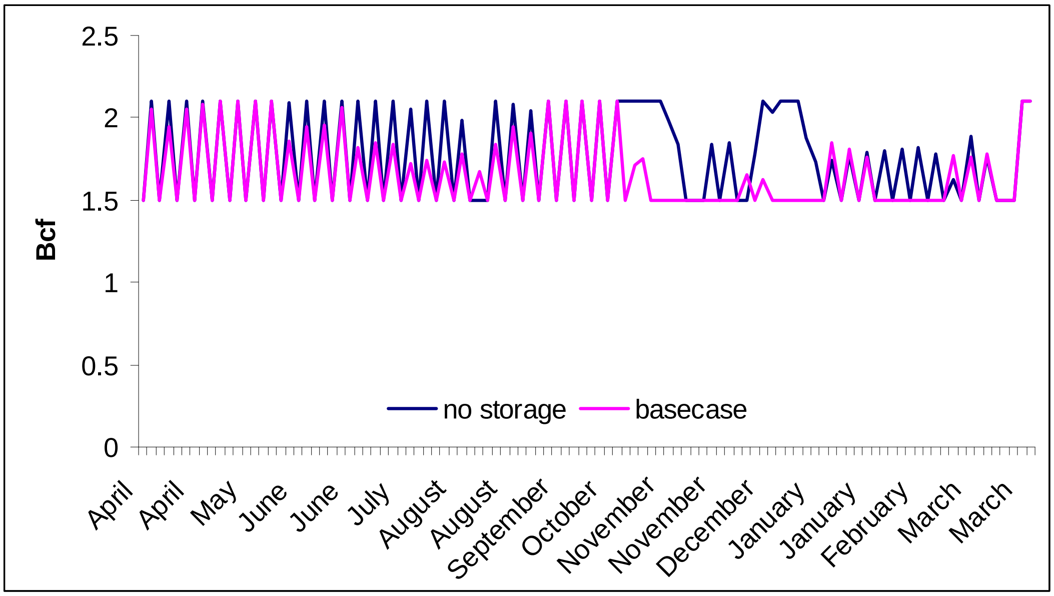

Figure 54: Simulated Linepack Profiles for No-Storage Case versus Base Case (Kern River pipeline)

According to Figure 52, the number of linepack cycles in the PG&E backbone increases when no underground storage is available, especially during the winter season. For most of the injection season and all winter, linepack is built up during the weekends at a rate of 300 million cubic feet per day (MMcfd) and drawn down Monday through Friday at a rate of 120 MMcfd. For the SoCal Gas system, however, linepack remains at its lowest bound for most of the withdrawal season. This difference between the cycling behavior of both systems would have to do with demand cycles being less acute in Southern than in Northern California (with the exception of the demand shifter for electricity generators in the winter). Off-system power generators display the same weekend shifts as those being served by SoCal Gas. Cycling capability in the Kern River pipeline which serves off-system generators is fully utilized during the injection season under the no-storage scenario.

Even though storage availability increases gas expenditures slightly, it increases the value of the objective function (i.e., the value of the gas allocation for California as a whole rather than for one particular group or region). The extra commodity cost is more than offset by the extra value that consumers derive from having smoother prices. When no underground storage is available, demand responsiveness plays a larger role as a buffer to equilibrate inflows and outflows each period. Deviations from desired consumption levels reduce aggregate surplus relative to that achieved in the base-case specification with underground storage.

CHAPTER 5: Scenario Analysis

The ultimate purpose of the model whose structure, parameters and calibration features have been examined in previous chapters is to perform scenario analysis. Given that it replicates reasonably well observed behavior for the reference period, we expect it to provide useful insights as to the effects that plausible and relevant scenarios for the California natural gas market would have on flow patterns, prices or storage behavior.

Scenarios are a version of sensitivity analysis of the type conducted in the previous chapter, except that they have some intrinsic rationale. The first scenario considered here, the removal of the requirement that the utilities accumulate a specified amount of reserves by the end of the injection season, relates to the last section of Chapter 4, except that this regulatory change is much more plausible than the closure of all underground storage in California. Scenarios usually involve a change of more than one parameter in a model, because if one feature changes so much, so might others. In the second scenario considered here, the opening of an LNG terminal directly serving California is accompanied by an addition to underground storage capacity. In the third scenario considered here, the use of natural gas for electricity generation in Ontario, which will divert gas from California, the crucial model question is the representation of the resulting change in seasonal and weekly cycles for the supply source from Canada. The model itself forces the user to consider such related changes in parameters.

5.1 Removal of Inventory Requirements for Core Storage

In the last few years, California storage capacity has always been full by the end of the injection season. Privately-owned storage where injection and withdrawal decisions by those who have capacity rights are unrestricted has been also filled up. Such behavior is not surprising considering the size of the *contangoes* observed in natural gas prices at the end of the injection season the last three years.

For utility-owned facilities, only a very small percentage of total inventory accumulation is decided upon by utility managers. Inventory requirements imposed by the California Public Utilities Commission (CPUC) on utilities combined with the injection rate capabilities result in a storage profile that from April through October repeats itself with very small variation. Even when, as in April 2001, the price spread is deeply in backwardation, utilities start pumping gas into their underground deposits in April 1 regardless, to make sure they will comply with regulatory requirements.

This scenario assesses the effects that removing core inventory requirements would have on total California inventory levels, on the location of those inventories, and on the distribution of those inventories across all the customer types. The forward curves for prices remain the same as in the base case. If little changes, the inventory requirements are irrelevant.

The first result to underline is that simulated California stocks stay the same throughout the year when the regulatory requirement is eliminated. Figure 53 addresses the question about distribution of inventories across the four underground deposits considered.

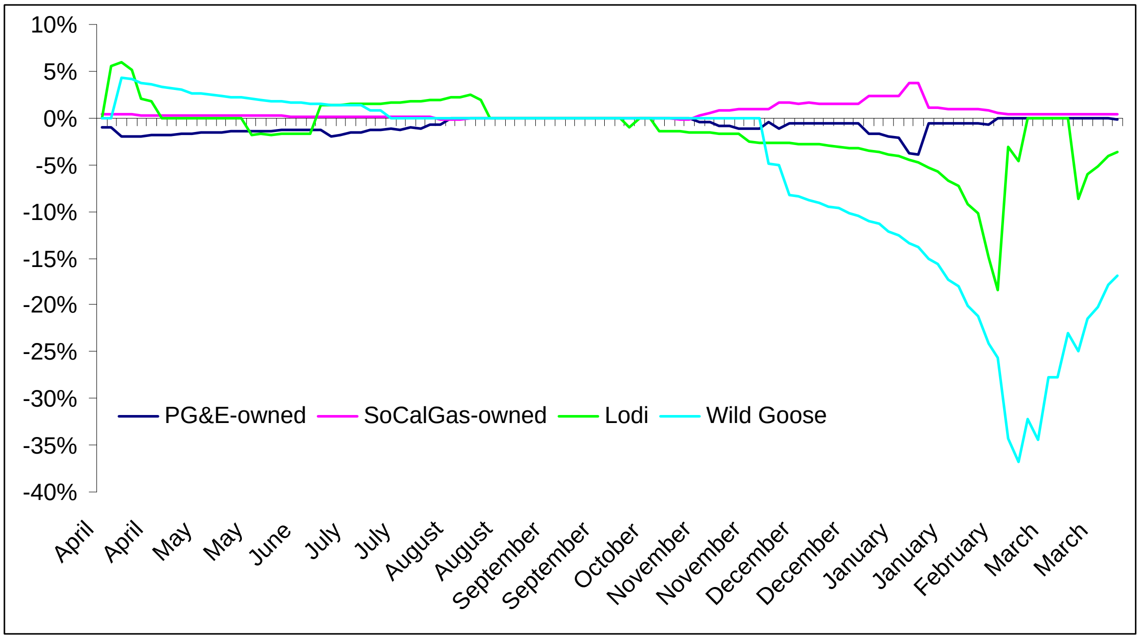

Figure 55: Simulated Deviations from Base Case Inventory Profiles

During the injection season, redistribution takes place across Northern California facilities. Less inventory accumulation than in the base case takes place at the low-deliverability facilities owned by PG&E. On the other hand, larger injections would be optimal at Wild Goose and Lodi so that these two facilities would be filled up earlier in the season than they did in the base case. Injecting more gas in those facilities gives the option of cycling it more times throughout the year, given that both Wild Goose and Lodi take less time to be filled up and drawn down than the utility-owned facilities. During the winter, larger volumes of gas are withdrawn from Northern California facilities but smaller from Southern California deposits.

Total stocks at the end of October are the same as in the base case at all facilities. Distribution of those amounts across customer types helps understand deviations from base-case withdrawal profiles. Table 12 shows the differences in stock ownership at the end of injection season between this scenario and the base case.

Table 12: Simulated Deviations from Base Case in Stock Ownership by Customer Type (Last weekend of October)

Facility ownership	Utility service area	Customer type	Deviation
Utility- owned	PG&E	core	-38%
		industrial	306%
		electricity generators	298%
	SoCal Gas	core	-60%
		industrial	93%
		electricity generators	98%
Private (Wild Goose)	PG&E	industrial	-14%
		electricity generators	17%
	Off-system	electricity generators	28%
Private (Lodi)	PG&E	industrial	41%
		electricity generators	-75%
	Off-system	electricity generators	5%

Core inventory requirements are binding in terms of the distribution of stocks at both utility-owned storage facilities. Once those constraints are removed, more end-of-summer stocks at facilities owned by PG&E and SoCal Gas would belong to noncore customers than in the base case. Wild Goose would be primarily used by electricity generators while industrial customers would have more presence at Lodi than in the base case.

Due to lack of any actual data at the level of customer type, the allocation of the observed stock levels at each facility was done by applying equal weights to all the customer types allowed to use that facility. This initial allocation – maintained both for the base case and for this scenario – influences the resulting injection profile. No swaps among customer types or between hubs in Northern and Southern California are allowed in the model – neither are they allowed by actual storage operators. A cubic foot of gas injected by an industrial customer at Wild Goose can only be consumed by an industrial customer in the PG&E service area.

Injection decisions by each customer type are determined by several factors. Fuel losses can be left out of the equation because the model assumes that they are the same for all facilities in Northern California. The demand profile of each customer and the performance profile of each facility are the main deciding issues.

The central outcome from this scenario is that, given the seasonal spread observed between April 2006 and November 2006, core inventory requirements result in over-allocation of inventories held by the "core" customer type. Ceteris paribus, the larger the share of winter core load requirements that is stored during the spring and summer months, the lower will be the spread between winter and summer prices. This is one of the arguments for imposing storage levels on utilities on behalf of their core customers. However, the smoothing effect of inventories could be achieved as well by removing regulatory requirements while allowing swaps. If inventory progress reports during the injection season were to reveal accumulation below a relevant seasonal average, the expectation would be that natural gas spot prices would jump considerably in November. This expectation of a large price increase should motivate members of any customer type holding storage capacity rights to use them. Even if their consumption profile does not peak in the winter, they would still be enticed by an attractive intertemporal spread, especially if they know they can swap those inventories at ease with other customers who will actually use them in the winter.

5.2 Introduction of LNG

The LNG project depicted in this scenario could represent the Sempra's Energía Costa Azul project scheduled to start operations off the coast of Baja California in early 2008. The Energía Costa Azul terminal will have a capacity of 1Bcfd and will connect with the Southern California pipeline system via the Otay Mesa Interconnect. Most likely, this introduction of LNG will be coupled with extra underground storage capacity in California.

Adding a new supply node into the model requires choosing reference quantities and prices as well as an elasticity parameter to calibrate a supply curve. The LNG to be received in Baja California will most likely proceed from Australia or Indonesia, the two largest producing countries in the Pacific basin. An average of prices paid for Australian and Indonesian LNG was used to construct the reference price profile for LNG supplied to the West Coast.[13] For the base case year, the LNG prices inputted in the model were, on average, 25% higher than the average price paid by California users for a basket of gas from traditional supply areas. The typical price profile for LNG traded in the Pacific basin peaks in the winter reflecting the relative seasonality in demand by competing countries like Japan and South Korea. Competing demand for Pacific Basin LNG by consuming countries in Asia is relatively higher in winter than in summer.[14] Thus, LNG volumes supplied to the new terminal in Baja will be relatively higher in summer

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[13] Prices were obtained from *Energy Prices and Taxes* published by the International Energy Agency.

[14] North America has in comparison more seasonal underground storage than the countries it competes with for LNG. Thus, the volumes that those competing countries receive are more tightly correlated with immediate demand requirements than in the case of the U.S.

than in winter. The volumes used for calibrating the LNG supply curve faced by California imply a load factor for the new terminal of 75% during the injection season and of 50% during the winter months.[15]

The elasticity of supply is assumed to be the same as for San Juan (0.93), the most elastic among the supply regions. It is therefore, inelastic. Such parameter value is consistent with spot trading representing only a small fraction of the LNG trading taking place at the new regasification facility.

Three sub-cases of this scenario are considered:

a) No additional underground storage capacity (*only LNG*)

b) Additional underground storage capacity in Northern California (*new storage north*)

c) Additional underground storage capacity in Southern California (*new storage south*)

Because current underground storage capacity is already being fully utilized in the base case, it seemed obvious that the capacity constraint would become binding in even more periods once LNG is introduced into the model. The extent to which LNG flows into California would be constrained not by capacity at the regasification terminal or competition by alternative markets but by insufficient storage capacity is thus a question worth pondering. The additional underground storage capacity (40 Bcf) corresponds to a plausible performance profile (i.e., a combination of injection and withdrawal rates for various stock levels) proposed by PG&E. The extra storage capacity would presumably be independently owned and located near market centers. Those LNG tanks located close to regasification areas would have a completely different cycling capability and are not considered in this scenario. Those tanks would have working gas capacity of approximately 5 days and would be constantly cycled to leave room for the next cargo.

[15] LNG liquefaction capacity is relatively scarcer than regasification capacity resulting in low utilization factors for regasification terminals.

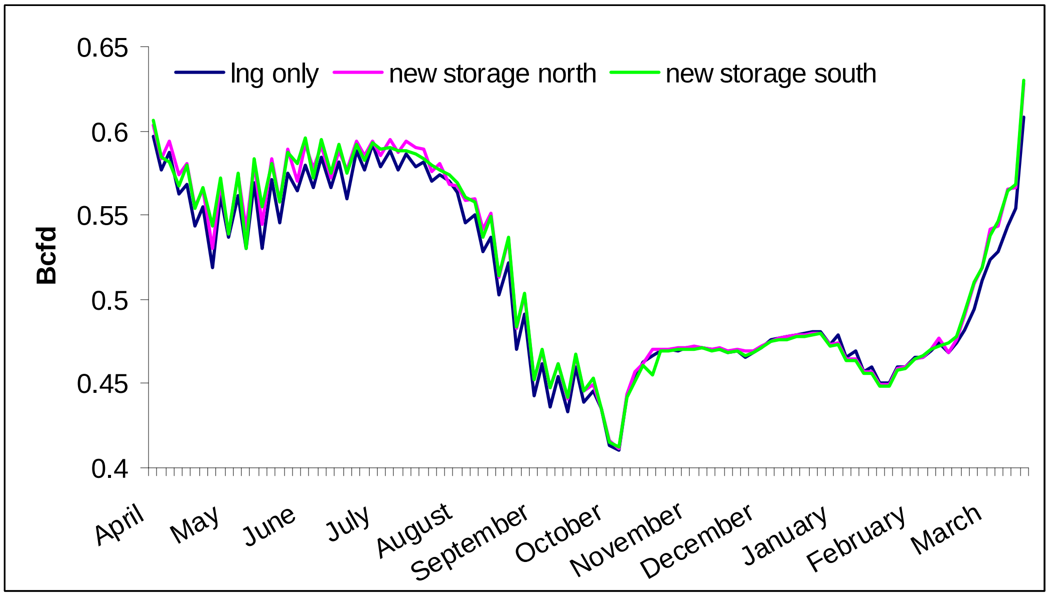

Figure 56: Simulated LNG Flows

Figure 56 shows the simulated LNG flow profiles under the three combinations of underground storage and LNG capacity considered. Extra storage capacity does not change the simulated flow profile, as it happens. The cases with additional storage display LNG volumes that are only slightly higher than those of the case with no additional storage.

The seasonality is acute with average volumes November through February that are, in average, 11% lower than during the rest of the year. Weekly cycles also change significantly at the two seasons that define the storage year. Deliveries of gas coming from the LNG regasification facility in Baja into the Southern California pipeline system from April through October are higher Monday through Friday than during the weekends. Such a pattern matches the overall consumption pattern during that season. However, during the winter, deliveries are flat Monday through Sunday. March appears as a transition month in which deliveries increase progressively until they reach the injection season's average.

Determining whether the volumes contributed by LNG to the total California system inflow constitute a net increase or simply displace gas from other sources is one of the important issues addressed by this network model. Because California is not allowed to be an exporter in any of the routes considered in the model, those are the only two possibilities to account for the volumes in Figure 56. As shown in Figures 57 through 59, the simulated outcome shows both displacement and a net increase.

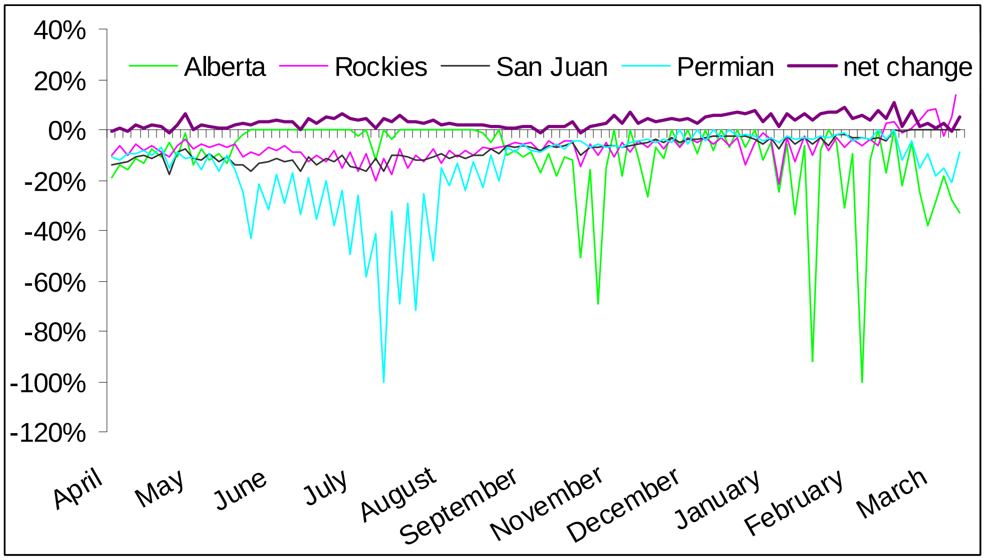

Figure 57: Simulated Changes in Flows (only LNG)

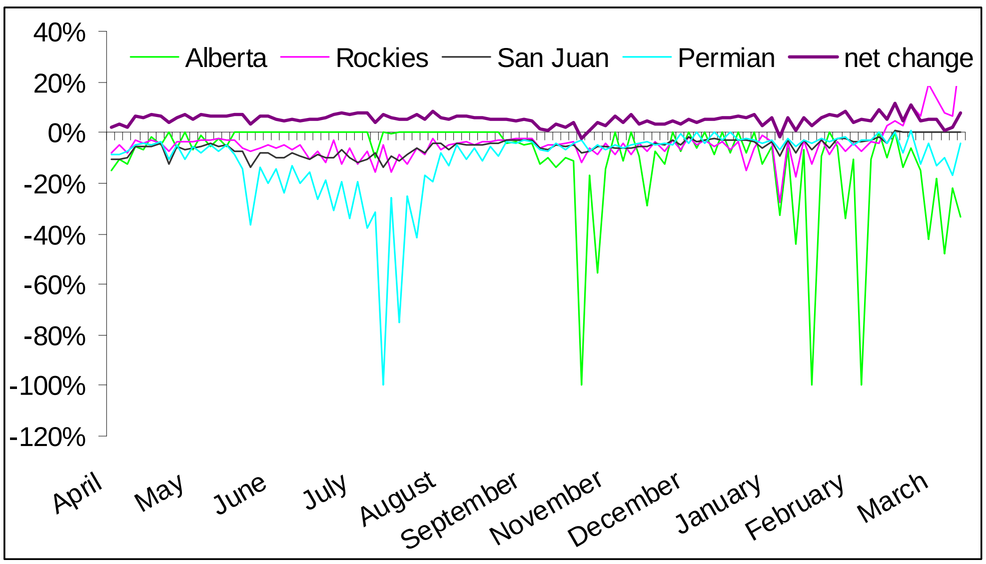

Figure 58: Simulated Changes in Flows *(*new storage north)

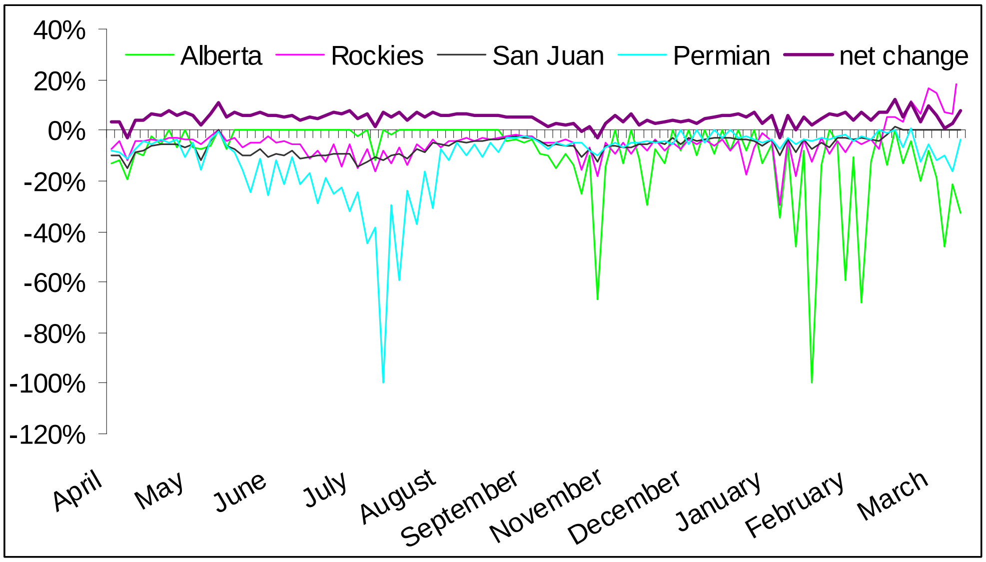

Figure 59: Simulated Changes in Flows (new storage south)

The three cases of the LNG scenario show only slight variations in the changes in the simulated supply mix. In all cases the patterns of displacement can be explained with reference to relative seasonality. Canadian gas is most displaced by LNG in the winter because that is when California constitutes the least attractive destination for this source of gas among the market centers Alberta serves. On the other hand, producers of Permian gas – the marginal source of gas in the base case – would lose a lot of clients in California during the summer months. Those customers would turn to lower priced LNG coming in from the regasification facility in Baja California during that part of the year.

Gas from the San Juan basin and the Rocky Mountains would experience smaller displacement effects. Gas brought from the Rockies actually would increase in March, especially in the scenarios with extra storage. This extra gas would be injected into the underground facilities.

In the case with no extra storage, the average net increase in flows is 2% of the base-case total during the injection season and 5% November through March. In the other two, the average is 5% all year long. Since LNG volumes do barely change across the three cases, it is the displacements that become smaller when extra storage capacity is created in the system.

The changes in supply mix brought about by adding LNG as an alternative source decrease the simulated average commodity cost by 2% during the winter season in the three cases. However, during the injection season, the reduction is 4% in the only LNG case but only 2.5% in the other two cases. In the variant of the scenario with extra storage capacity, the increase in quantities brought into the state during the injection season is the dominant factor.

Because supply curves are upward sloping, larger volumes only come at higher prices. The marginal cubic feet of gas brought into California by LNG tankers during the injection season are, according to simulated results, 4 c/MMBtu more expensive than one more additional cubic feet from a basket of all the other supply options. During the winter months the difference shrinks to 2 c/MMBtu. Figure 60 displays the average commodity cost and LNG price profiles for the case with only addition of LNG. The profiles are very similar for the other two cases.

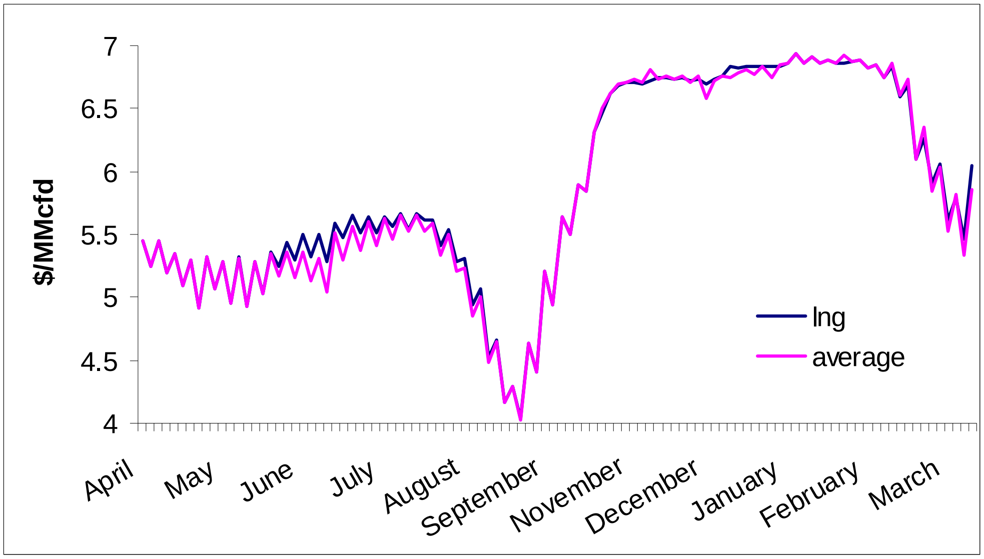

Figure 60: Simulated Average Commodity Cost versus Simulated LNG Price (only LNG)

The nonlinear program is designed to look for the most efficient supply mix, which would be the one in which the delivered marginal costs of gas from each source are equal, as long as no capacity or regulatory constraints are binding. As spatial arbitrage opportunities are exhausted, differences in simulated commodity costs reflect differences in transportation costs to the market centers. A LNG cost that is slightly above the average commodity cost corresponds to a transportation fuel loss smaller than the average for the other sources (1.5% versus 2.7%).

In this model, the Citygate price is nothing but a weighted average of delivered costs. The delivered cost includes the cost of the commodity but also the losses incurred through transportation and storage activities. Thus, the simulated reductions in the cost of gas enabled by the addition of a new supply source will be passed through to final customers. Table 13 and Figure 61 summarize the changes in simulated Citygate prices relative to the base case. These are relatively large “indirect” effects, as these network models go.

Table 13: Average Seasonal Changes in Citygate Prices with respect to Base Case

	Only LNG			New Storage North			New Storage South		
	Off-System	PG&E	SoCal Gas	Off-System	PG&E	SoCal Gas	Off-System	PG&E	SoCal Gas
Summer	-4.7%	-4.5%	-4.75%	-3.03%	-2.95%	-3.14%	-3.03%	-3.04%	-3.16%
Winter	-0.97%	-2.78%	-3.17%	-0.48%	-2.67%	-2.66%	-0.6%	-2.67%	-2.75%

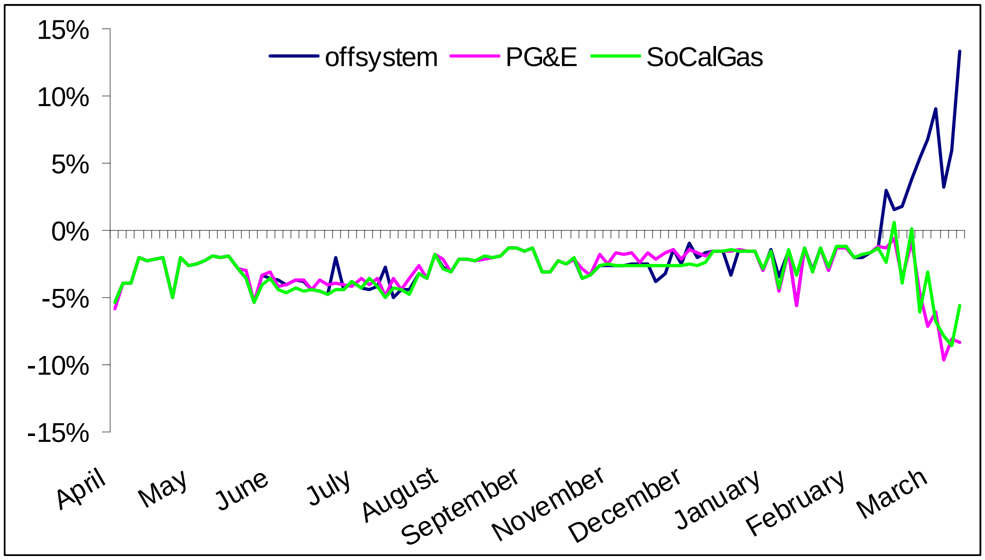

Figure 61: Simulated Changes in Citygate Prices with respect to the Base Case (new storage north)

According to Table 13, wholesale prices faced by all customer types served by either PG&E or SoCal Gas or bypassing the utilities are lower in all periods and cases considered than in the base case. The decrease is always larger for Southern California customers, even in the scenario in which extra storage capacity is installed in Northern California. Thus, proximity to the new gas source is directly correlated with savings. Decreases are overall larger in the case with no storage additions. This result obeys to the same reasons commented above when explaining the changes in commodity costs. The decrease is bigger for the scenario with no extra storage than for the other two. However, the value of the objective function is biggest for the cases with extra storage meaning that a price decrease cannot be automatically interpreted as good for society, at least in the context of this model. Here, a smaller cost is associated to a smaller volume stored and consumed, which might decrease the size of the surplus triangles (the areas under the demand and the supply curve).

The profile in Figure 61 is similar to the one for the other two cases. The increase in price for off-system electricity generators in March, while prices for the other two groups are going down, is the most attention-catching feature of the graph. These electricity generators are the ones injecting gas in the new storage facility the last month of the year. They are willing to pay a higher price than utility customers to accumulate gas that will help them face their summer demand peak.

For those who hold storage capacity, the seasonal price spread is just as important as the price levels. Therefore, they would be interested in knowing if addition of LNG will strengthen or weaken the spread. Table 14 shows the percentage difference between the winter and summer average Citygate prices for the base case and the three LNG scenarios.

Table 14: Percentage Difference between Winter and Summer Simulated Average Citygate Prices

Base Case	Offsystem	19.83%
	PG&E	23.00%
	SoCal Gas	22.19%
Only LNG	Offsystem	24.32%
	PG&E	25.34%
	SoCal Gas	24.32%
New Storage North	Offsystem	22.73%
	PG&E	23.44%
	SoCal Gas	22.91%
New Storage South	Offsystem	22.63%
	PG&E	23.55%
	SoCal Gas	22.85%

Bringing LNG into the supply mix broadens the differential between summer and winter prices. Thus, it increases the value of storage. LNG gets relatively more expensive during the winter because of competition by alternative markets in the Pacific Basin. The average cost of the other supply sources also increases during the winter season. LNG reinforces the existing seasonality in costs.

Finally, the changes in storage patterns brought about by the introduction of LNG need to be analyzed. Figures 62 through 65 compare the simulated profiles for each of the base case facilities under different configurations of the LNG scenario. The peak inventory remains at 100% in all cases and facilities.

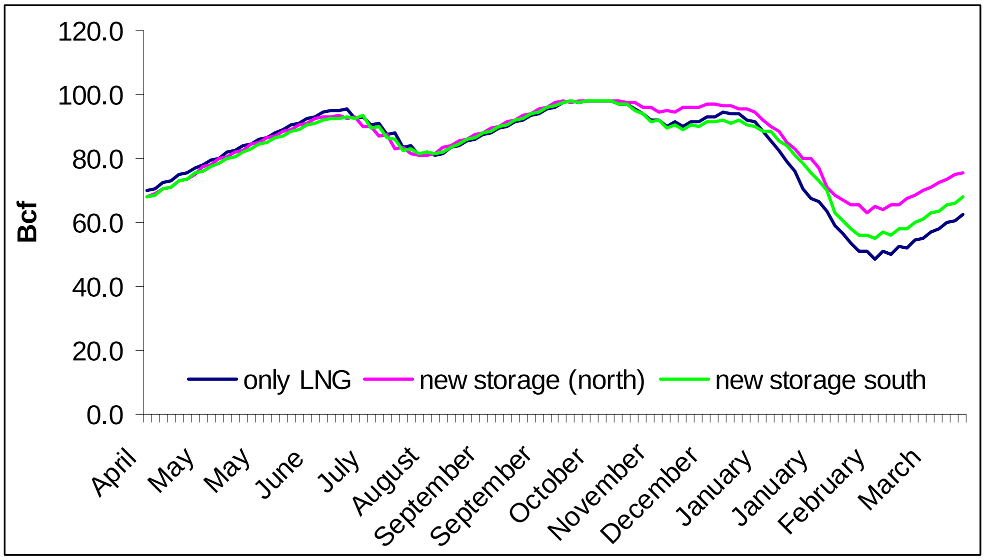

Figure 62: Simulated Inventory Profiles for PG&E-owned Facilities under LNG Scenarios

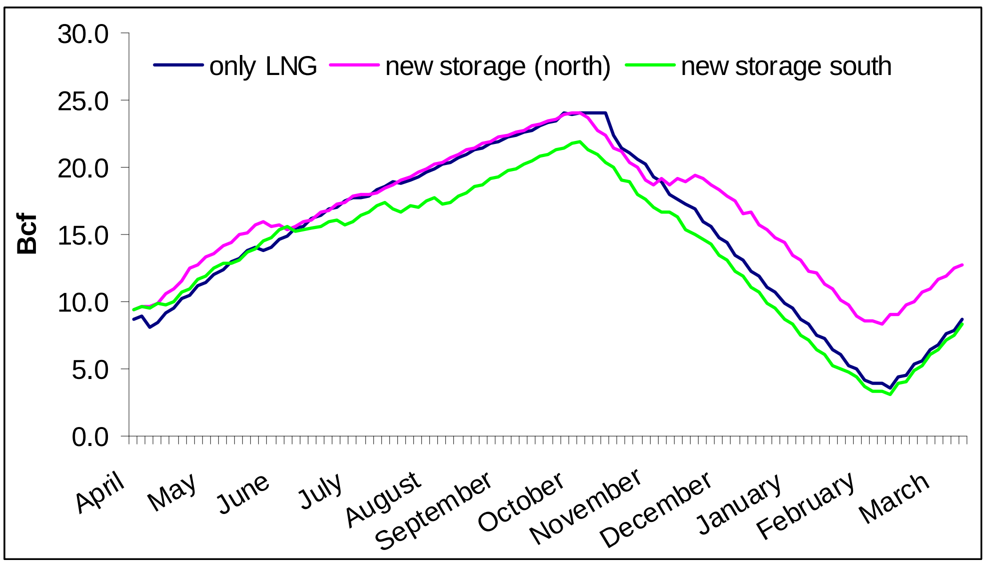

Figure 63: Simulated Inventory Profiles for Wild Goose under LNG Scenarios

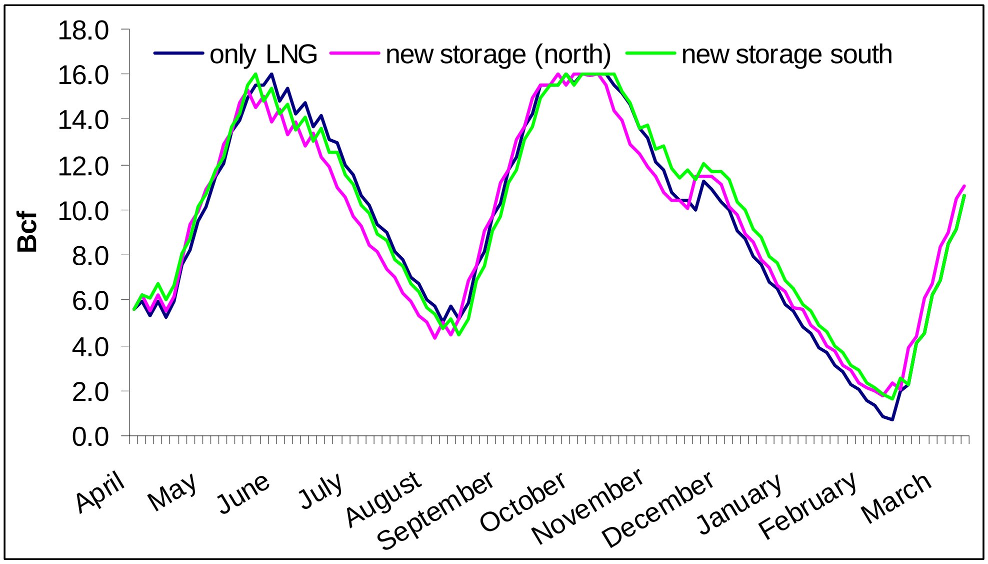

Figure 64: Simulated Inventory Profiles for Lodi under LNG Scenarios

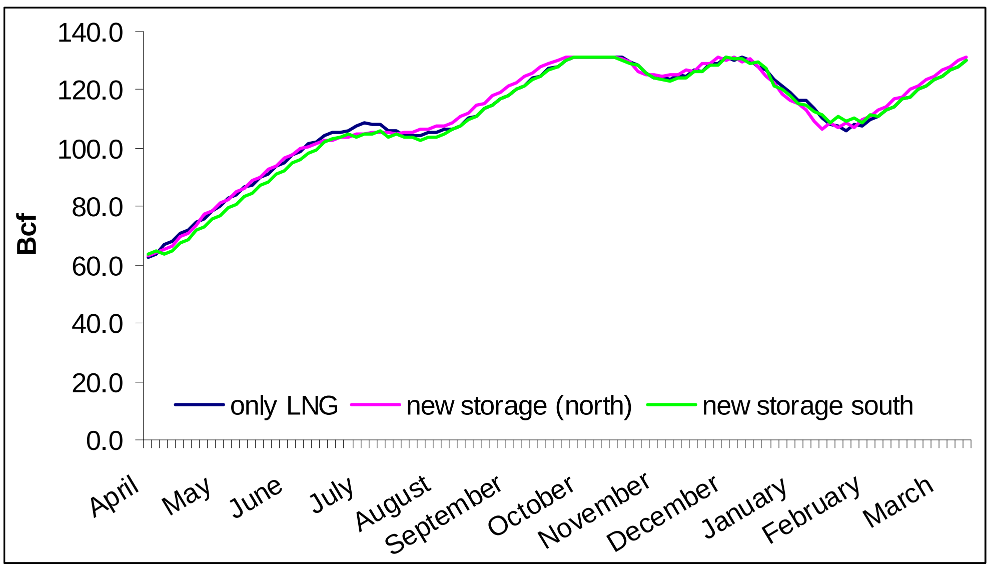

Figure 65: Simulated Inventory Profiles for SoCal Gas-owned Facilities under LNG Scenarios

Extra storage capacity does not change much the simulated profiles of the base case facilities. Underground deposits in Northern California, regardless of ownership, all display the largest inventory levels at the end of the storage year in the case in which extra capacity has been located in that region (new storage north). The additional capacity helps serving winter load requirements so that more gas remains at the older deposits by the end of March. Because off-system generators experience a large price increase in the last period, inventory accumulation at the end of the year is sensible for that group. Wild Goose displays the most notable divergences across the three cases. When the additional storage capacity is located in Southern California, some of the gas that was initially being stored at Wild Goose is displaced towards the new facility. On the other hand, when the extra 40 Bcf are placed in the northern part of the state part of the withdrawals which would have otherwise come from Wild Goose would come now from the new facility. Thus, Wild Goose functions as the marginal facility which is a complex function of the performance profiles of all the storage facilities in the network at one point in time. In the base case, Wild Goose is at the middle of the spectrum in terms of deliverability. It is capable of cycling gas more times a year than the utility-owned facilities but less times a year than Lodi. When the new facility is added, Wild Goose is pushed, in relative terms, to the higher deliverability end of the spectrum.

Not only the capacity at existing facilities is filled up by the end of October in all cases but, in those cases where extra capacity is added, that additional facility is also fully utilized as can be seen in Figures 66 and 67.

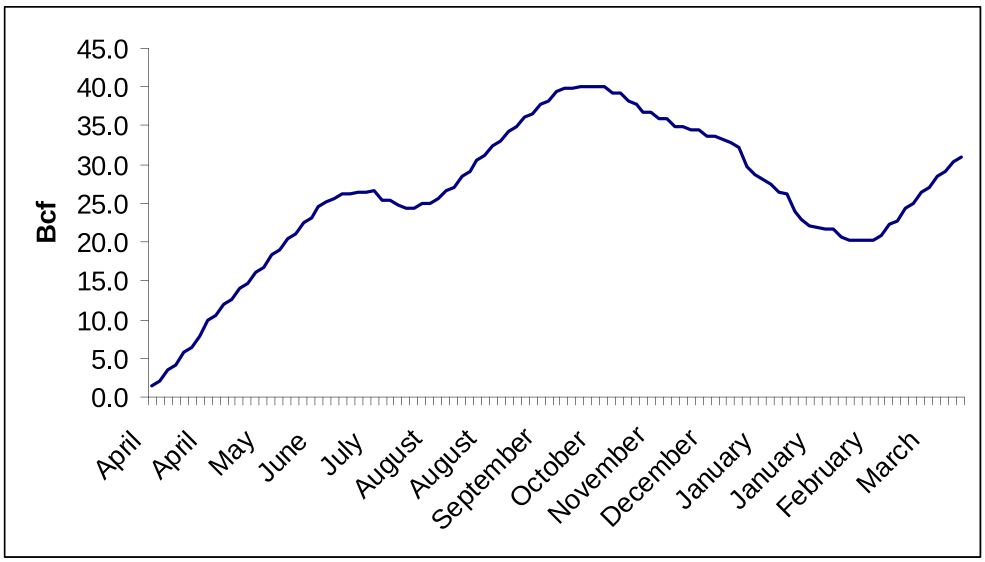

Figure 66: Simulated Inventory Profile on New Facility (new storage north)

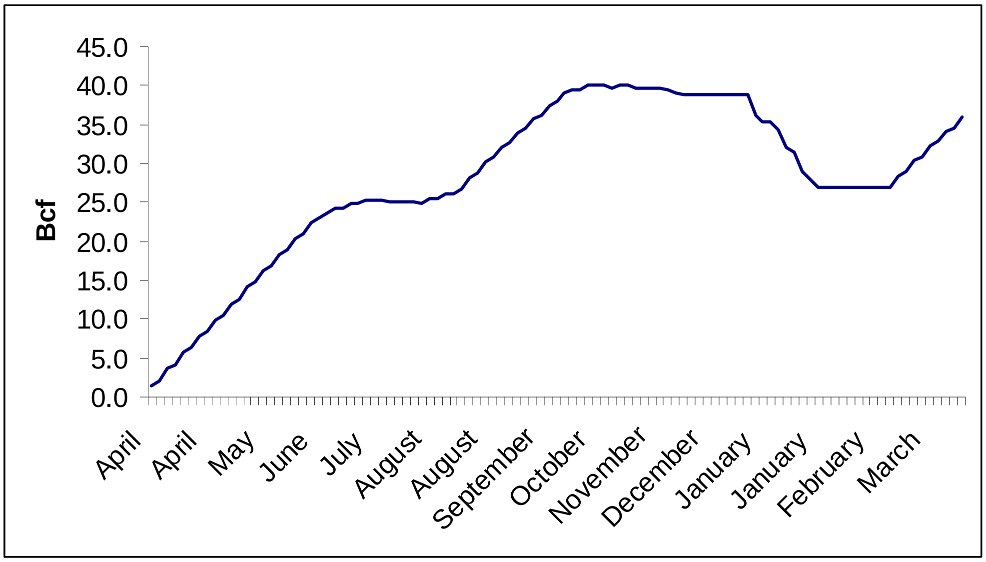

Figure 67: Simulated Inventory Profile in New Facility (new storage south)

The extra 40 Bcf would be managed in a similar fashion whether it would be located in Northern or Southern California. The simulated profile contains, in both cases, two and a half cycles. The major difference is that winter withdrawals would start much later in Southern California than in Northern California. Such a divergence is consistent with lower temperatures arriving later to Southern California, which would make residential customers in that area use their heaters less and later in the season. Seasonality interacts with LNG shipments.

5.3 Ontario's phase-out of its Coal-Fired Electricity Plants

Ontario is planning to eliminate 7.3 gigawatts (GW) of coal-fired generation capacity by 2009, about 25% of its current total generation capacity. Combined-cycle generation facilities fueled with natural gas will replace much of the lost capacity. Therefore, competing demand for Canadian gas will increase. The Canadian demand outlook, in turn, affects the residual supply curve faced by California. Traditionally, California has purchased more Canadian gas in the summer than in the winter. With substantial new natural gas demand for electricity generation in Ontario, seasonality in the volume of gas that flows to California should be expected to decrease.

The reference volumes used in this scenario to construct the residual supply curve for California are steadier throughout the year and closer to base-case winter than summer flows. This scenario assumes that all 7.3 GW of coal-fired generation capacity would be replaced by high efficiency gas-fired power plants, which according to the Ontario Clean Air Alliance (OCAA) would increase North American natural gas consumption by 2.4%. Such an increase will most likely not be uniform throughout the year. The scenario assigns 65% of the increase to the summer months – to account for the fact that natural gas demand for electricity generation is typically higher in the summer – and the rest to the period going from November to March. The effect that such an increase in competing demand would have on the Canadian residual supply curve faced by California would depend on the production response as well. The reference quantities used to construct the new residual supply curve for California imply reallocation of the existing Alberta production (no supply response in the short-run) in proportions corresponding to the seasonal fractions of Canadian production directed to the main consuming areas in the United States (California, Midwest and Northeast) in the base case.

Given the assumptions of one-to-one substitution between coal-fired and gas-fired generation capacity and of no production response, the results from this scenario should be interpreted as an upper bound on the reduction of Canadian gas that Ontario´s phasing-out policy would bring about for California. Increased demand requirements in Ontario make Canadian flows relatively more scarce and, therefore, more expensive for California. Table 15 compares the resulting optimal supply mix with the one from the base case.

Table 15: Simulated Percentage Deviations in Flows with respect to Base Case

	Canada	Rockies	San Juan	Permian	In-state	Total
Summer weekday	-2.3%	0.9%	1.0%	1.2%	0.2%	-0.1%
Summer weekend	-1.7%	0.2%	0.4%	0.4%	0.0%	-0.3%
Winter weekday	-2.6%	0.0%	0.1%	0.4%	0.0%	-0.5%
Winter weekend	-6.0%	0.1%	0.5%	0.2%	0.1%	-0.5%

Decreases in Canadian flows are partly replaced by flows from the other producing regions serving California but the net effect is a decrease in total flows. The Permian basin – the marginal source of gas in the base case specification – is the one experiencing the largest increase. The largest percentage decreases in Canadian flows correspond to the winter season (especially weekends). In absolute terms, the decreases for the four periods considered range between 27 MMcfd for summer weekends and 37 MMcfd for summer weekdays. Those volumes represent less than 1% of total flow coming into California any period of the year.

Simulated consumption levels do not change. However, the marginal value of consumption now equates the marginal cost of supplies at a slightly lower supply level. Figure 68 shows that small modifications in the storage profile close the gap between unchanged consumption and smaller incoming flows. Lodi – the highest deliverability facility – experiences the largest changes. Under this scenario, simulated injections in Lodi take place earlier in the year and withdrawals also start sooner to compensate reduced Canadian flows. For the rest of facilities, simulated injections during the first half of the year are lower than on the base case while winter withdrawals are larger. At the end of the storage year, simulated stock levels are below base-case levels for all facilities except the ones owned by PG&E.

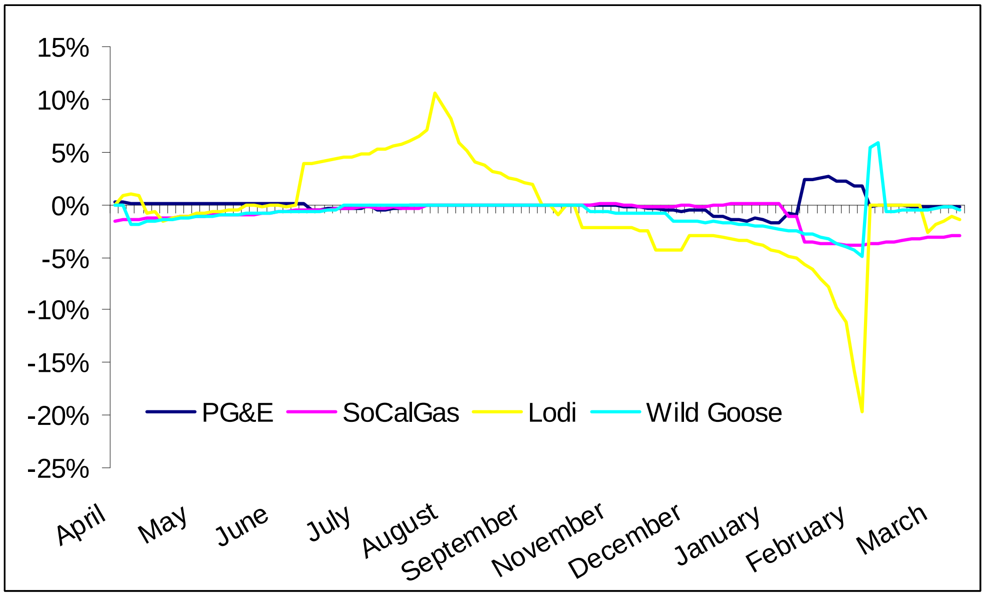

Figure 68: Percentage Deviations in Simulated Stock Levels WRT Base Case

All in all, the effect of coal plants being phased-out in Ontario is almost negligible for California. The California network would respond with a mixture of less, more expensive supplies – total expenditures in gas are slightly higher than in the base case – and adjustments in storage profiles. However, this scenario only partially accounts for the indirect network effects that this policy would trigger. Other market centers which consume Canadian gas (For example, Chicago and New York) would have to make up for their respective reductions from that source increasing their inflows from other producing regions. Some of those would come, directly or indirectly, from the Rocky Mountains or the Southwest basins and increase competition faced by California for gas from those producing regions. The change in Ontario's source for electricity will affect everyone throughout the North American natural gas network, not just through an increase in average demand but through the alteration of seasonal and weekly patterns.

GLOSSARY

Billion cubic feet	Bcf
Billion cubic feet per day	Bcfd
California Public Utilities Commission	CPUC
Cents per million British thermal units	c/MMBtu
Gigawatts	GW
Liquefied natural gas	LNG
Million cubic feet	MMcf
Million cubic feet per day	MMcfd
Ontario Clean Air Alliance	OCCA
Operational flow orders	OFO
Pacific Gas and Electric Company	PG&E
San Diego Gas & Electric Company	SDG&E
Southern California Gas Company	SoCal Gas
Western Canadian Sedimentary Basin	WCSB
West Texas Intermediate	WTI
With respect to	WRT

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