Energy Policy and Economics 013

"THE 'SUPPLY-OF-STORAGE' FOR NATURAL GAS IN CALIFORNIA"

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September 2005

This paper is part of the University of California Energy Institute's (UCEI) Energy Policy and Economics Working Paper Series. UCEI is a multi-campus research unit of the University of California located on the Berkeley campus.

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FOR NATURAL GAS IN CALIFORNIA

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Abstract: Do natural gas storage decisions in California respond to futures price spreads? Daily data about flows into and out of storage facilities in California over 2001-2005 and daily price spreads on NYMEX are used to investigate whether the net injection profile is consistent with the “supply-of-storage” curve first observed for wheat by Holbrook Working. Storage decisions in California do seem to be influenced by intertemporal signals on NYMEX, but the effect is small. Strong seasonal and weekly cycles determine the net injection profile to a considerable extent. Regulatory requirements and operational constraints also limit the size of the response to intertemporal arbitrage opportunities. Results are surprisingly sensitive to the degree of aggregation.

1. INTRODUCTION

Futures markets provide intertemporal price signals. As Working (1934) first showed for wheat and others have observed for many other commodities,[1] at least some, if not most, market participants pay attention to those intertemporal price signals. Those holding stocks of wheat look to the nearby spread, holding considerably more stocks when the nearby spread is in contango than when it is in backwardation.[2] Those holding commercial stocks in Chicago are extremely sensitive to the spreads in wheat futures prices at the Chicago Board of Trade, commercial holders outside the delivery area less sensitive, and farmers retaining wheat on farm least sensitive. Those agents whose behavior is not closely tuned to the intertemporal signals in a futures market could simply be inattentive but they also could be experiencing another signal or facing constraints that make them less able to respond. Working (1948 and 1949) called the aggregate relationship a "supply-of-storage" curve.

Daily data from April 2001 to April 2005 for natural gas stocks and flows into and out of storage within California allow an examination of the reach of futures prices in the North American natural gas market. Although not efficient in pricing in its first years (Herbert, 1992), the NYMEX natural gas futures market is now deep and active. Yet California is far from and only indirectly connected to the pipeline system centered on the Henry Hub in Louisiana, the delivery location specified in the NYMEX contract.[3] Sometimes the intertemporal spread in the NYMEX futures market is in contango while

[1] For eggs and butter (Brennan, 1958), for cotton and wheat (Telser, 1958), for coffee and cocoa (Thompson, 1986), for fuel oil (Lowry, 1988), for copper (Larson, 1994) and (Thurman, 1988).
[2] The spread is said to be in contango (backwardation) when the difference between simultaneously quoted futures and spot prices is positive (negative). Often, the next-to-expire futures month is taken as a spot price.
[3] Brinkmann and Rabinovitch (1995) concluded that those in California would find limited hedging effectiveness to NYMEX futures.

the effective local spot-forward spread in California is one of backwardation and an inducement to withdraw stocks in that region.[4] Two of the four storage facilities within California are operated by the two main distribution utilities, constrained by regulators to have a set quantity in store each November 1. To meet that constraint, the two utilities, which are not organized as nimble trading firms, might plan their injection schedule regardless of the price spread at the time of their decision, let alone the subsequent day-to-day fluctuations in that signal. The other two facilities in California are operated primarily as toll storage - charging a set price for the storage service for a set time - which has enticed a wide range of customers, some of whom are purely traders and who might be closely tuned to NYMEX futures spreads. The following analysis takes further advantage of the highly disaggregated data set to investigate how the "supply-of-storage" relationship varies across these four facilities and how it diverges at different frequencies of measurement.[5]

2. CHARACTERISTICS OF NATURAL GAS STORAGE FACILITIES

Apart from California's remoteness to the delivery point for the NYMEX futures contract and of the public utility character of the two biggest storage facilities, a third reason exists for making natural gas in California an interesting example of the relationship between futures spreads and stocks: The storing of natural gas presents

[4] Wright and Williams (1989) showed that the sign of the effective price spread depends on the degree of spatial aggregation considered.

[5] Daily data for stocks and net injection were provided by the California Energy Commission. Daily spot price data come from Natural Gas Intelligence, a reporting service that surveys transactions at trading hubs across North America. Finally, the futures price data come from Norman Consulting and the NYMEX website.

logistic and operational difficulties compared to the storage of bulk commodities such as wheat, to which most of the "supply-of-storage" literature has been dedicated.

Unlike stocks of grain, for which discontinuous supply is the main source of seasonality, inventories of natural gas display a strong seasonal pattern originating on the demand side. So strong is this seasonality that there are two official seasons in natural gas storage, one for injection that runs April through October and one for withdrawals going November through March, delimited by the assumed beginning and end of residential heating demand. When the relevant intertemporal price spreads are in significant contango, a switch from drawdown to accumulation of inventories is possible for both grain and natural gas.

Although grain elevators can be built virtually anywhere, natural gas can be stored only underground, in depleted reservoirs, aquifers, or salt caverns. The geological characteristics of the formation partly determine how flexibly the facility can be operated. As for the costs of injecting storage into a facility, compressors use natural gas itself as fuel to push the flow into the reservoir. There is no analogue for such a physical cost when storing grain.[6] The amounts of gas that can be put in and out of a facility are limited by the corresponding injection and withdrawal maximum rates or by the capacity in the connecting pipeline, whichever is less.[7] Although loading and unloading constraints do affect grain storage (Brennan, 1994), they seem less of an issue for a grain

[6] Unlike grain bins, which can be emptied, natural gas storage facilities often need some minimum quantity present to keep the geological formation intact. This physical reality is recognized in the concept of "working gas", which is the relevant storage amount from a marketing perspective.

[7] Unlike for liquids like gasoline, pipeline or storage capacity for natural gas can be increased with additional compression. The concept of "capacity" acknowledges, however, the rapidly increasing costs beyond some levels of usage.

elevator, because the supply of transportation services can be considered nearly perfectly elastic for a single facility.[8]

Natural gas flowing into or out of a storage facility competes for pipeline space with flows for other immediate uses or for injection in other facilities. Net injections display a weekly cycle that peaks during the weekend, when other demand requirements are lower. The weekly profile of pipeline load is the mirror image of that for storage net injection. The amount of gas packed in the pipelines decreases Monday through Friday and is built up again during the weekend. Excessive or insufficient linepack often results in pipeline pressures that threaten to jeopardize the operation of the system. In those instances, system operators call operational flow orders (OFOs). When an OFO is in place, customers must align more closely the amount of gas they request to be put in the pipeline and the amount they actually consume day by day; otherwise, they pay a penalty. Most OFOs correspond to situations of high pipeline load and so can be viewed as a proxy for congestion in some intrastate pipelines. During the period under consideration, OFOs were in place 12% of the time in the PG&E system in Northern California and 7% of the time in the SoCalGas system in Southern California.

Natural gas storage facilities cannot be viewed as self-contained operations but as nodes of the Californian, and in a broader sense, of the North-American natural gas network. Injection and withdrawal decisions cannot be taken without accounting for the operational status of interconnecting pipelines, which are, in turn, connected to the backbone pipelines owned by distribution utilities and ultimately to interstate pipelines. California receives its gas from Canada, the Rocky Mountains, and the Southwest

[8] Systemwide, the constraints on transportation capacity may have profound affects on grain storage (Brennan, Williams, and Wright, 1997).

producing basin.[9] Once the gas is inside the state, it is either delivered by the interstate pipelines or distribution utilities to their respective customers, or stored.

Figure 1 displays the location of the main intrastate pipeline and storage infrastructure in California (California Energy Commission, 2002). SoCalGas and PG&E more or less divide California south and north,[10] and operate with minimal interconnection of their backbone networks, even though in several places their pipelines are merely a few miles apart.[11] These utilities' operations are subject to regulatory requirements, which likewise lack coordination. Each utility must accumulate a specified level of stocks by the beginning of the official withdrawal season, to ensure they will satisfy residential heating demand. PG&E and SoCalGas are entitled to recover their annual rate base according to rate-of-return style regulation. In contrast, Wild Goose and Lodi mainly store for others at market-based rates, while also engaging in short-term trading on their own account.[12]

Storage facilities in Figure 1 are aggregated into four points, even though the two utilities each have several facilities in their two general areas marked in Figure 1. As the utilities provide data aggregated over the distinct facilities, that is the unit of analysis used here. Most of the capacity in utility-owned facilities is dedicated to "core"

[9] In-state production contributes about 15% of California's consumption.

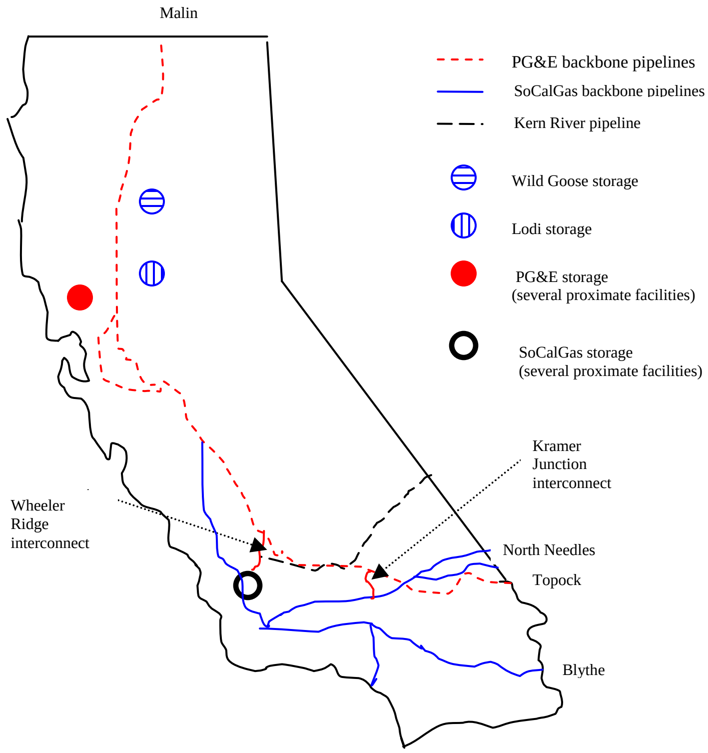
[10] San Diego Gas and Electric (SDG&E) serves the San Diego area. All the gas entering the SDG&E pipelines comes from the SoCalGas system and no storage capacity exists in the area. Thus, in this analysis, SDG&E will be viewed as a customer of SoCalGas.

[11] That is, various routes into California do not compete directly, unlike the situation De Vany and Walls (1996) have found for parts of the network in the Eastern U.S.

[12] The Wild Goose facility gets its name from the prestigious hunting club below which a depleted gas field existed. Locating a storage facility there involved extra cost and inconvenience (the compressors had to be muffled), but was nonetheless the best option because of the scarcity of locations with similar geological features and proximity to the PG&E backbone pipeline system. The Lodi facility gets its name from the nearest town.

Figure 1

Physical configuration of the California natural gas network



customers, although industrial users and electricity generators can also acquire storage space in them. Independent facilities serve only "noncore" customers.

Table 1

Aggregate natural gas storage capacity in California[13]

Working gas capacity (Bcf)[14]	Maximum injection rate (MMcfd)	Maximum withdrawal rate (MMcfd)
256	2,025	5,714

[13] The capacity figures in Table 1 include the recent expansion undertaken at Wild Goose, which came online in April 2004 and added 10 Bcf of working gas storage capacity, 370 MMcfd of injection capacity, and 280 MMcfd of withdrawal capacity. Nationwide storage capacity is some 9,000 Bcf.

[14] 1 Bcf = 1,000 MMcf. Natural gas flows are normally expressed in million cubic feet per day (MMcfd). On the other hand, the convention for prices is to use dollars per million British termal units ($/ MMBtu). 1 MMBtu is approximately equal to 1 MMcfd. MMcfd is a measure of volume while MMBtu refers to the heating power (the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit).

Given the amount of storage capacity available statewide and the maximum injection rate, it would take 127 days, approximately four months, to fill it. In practice, the injection season has to be longer (seven months officially), because there is not enough pipeline capacity available to bring all that gas into the storage facilities over four months while satisfying daily consumption requirements.

One of the basic trade-offs in designing energy distribution networks is that between pipeline capacity and storage capacity. In the producing areas, nature herself provides storage facilities. Storage facilities in consuming regions would be unnecesary if pipelines were built big enough to satisfy peak daily demand. Because such a configuration is clearly cost inefficient (huge pipelines would be half empty most of the year), storage in consuming areas comes into play. The flexibility with which storage facilities can be operated largely depends on the balance between working gas capacity and rates of injection and withdrawal. A low injection rate or a tiny pipeline interconnection diminishes the usefulness of a storage reservoir because it would be infeasible to cycle its contents in one year, the needed seasonal cycle imposed by natural gas demand.

Over the last twenty years, deregulation and the introduction of a futures market for natural gas have changed the character of operations for natural gas storage (Doane and Spulber, 1994). Previously, services related to storage were bundled with transportation, as they were strictly tools for balancing pipeline flows and for smoothing seasonal price fluctuations derived from the demand cycle.[15] Independent storage facilities, one of the byproducts of the deregulation process in the natural gas industry,

[15] Indeed, transportation expenses themselves were often bundled into a pan-seasonal, pan-territorial price of natural gas (Hubbard and Weiner, 1991).

have largely contributed to the rise of market-oriented uses of storage capacity. One of the hypotheses to be tested in the econometric analysis here is whether the two new independent facilities in California, which differ from those owned by California utilities in terms of regulatory requirements and customer type, appear as significantly more price-responsive than the utility-owned ones.

3. INTERTEMPORAL SPREADS AND STORAGE IN CALIFORNIA

According to the theory of the "supply-of-storage", stocks are held whenever their value, as reflected in futures prices, increases sufficiently over a given period so as to cover storage costs. The bigger the contango, the greater the quantity that should be placed into storage. By the same logic, gas should be released from storage facilities whenever the spread is below the holding cost and even more so when the value of the commodity is expected to fall, as in a backwardation. These propositions emphasize the allocative role of futures prices, according to which spreads guide inventory levels. However, in the "supply-of-storage" literature, intertemporal spreads have been considered the dependent variable and explained by the stock level, in the sense that fitted relationships minimize the sum of squared errors among spreads rather than stocks. This direction of causality is merely a convention established in Working's seminal studies. At the aggregate level, stocks and spreads are simultaneously determined. Granger (1969) has argued that bi-directional causality may appear as a byproduct of data aggregation. When data sets are used with finer sampling, whether over space or time, *a priori* information about the ordering of the variables often results in models where only one direction of causality makes sense.

Figure 2 can be interpreted as California's "supply-of-storage" curve for the April 2001- March 2005 period in emulation of Working's original plots for wheat. Stocks as of the first days of April, July, October, and January are plotted against the monthly return implied by the two-month spreads observed on those dates.[16] Even though the highest inventory buildups in California coincide with the deepest contangoes, approximately the same spread can result in very different stock levels. Part of that variability in stocks results from the seasonality in the inventory profile. The lowest stocks are not those simultaneous with the backwardations. That is to say, the shape of the curve fitted to Figure 2 does not accord well with the "supply-of-storage" theory. The expected positive relationship between stocks and the spread shows up more clearly in Figure 3, however.[17] The difference is that, in Figure 3, stocks on a given day are plotted against the return per month implied by the two-month spread observed two months before rather than the two-month spreads observed on the day to which the stock level refers. The spreads evidently have influenced the subsequent stocks.

Comparison of Figures 2 and 3 suggests that, at this degree of spatial aggregation, it is spreads that determine stocks rather than the other way around. The deepest backwardation (-0.371 $/MMBtu per month in April 2001 with respect to the June contract) resulted in the lowest stock level two months later, although the biggest contango (0.904 $/MMBtu per month in November 2004 with respect to the January 2005 contract) did not provide enough of an incentive to fill the storage capacity, because

[16] The spread is defined as the further-to-expiration minus the closer-to-expiration contract. The spot price level at Malin on the Oregon border during this period averaged at 4.11 $/MMBtu but went as low as 1.22 $/MMBtu and as high as 11.46 $/MMBtu. Nearby futures prices were nearly as variable, around a slightly lower mean.

[17] Over these four years, interest rates were stable and unusually low, so the spreads are not adjusted for financing costs.

it happened at a time of year in which demand for heating dictates withdrawals.[18] Thus, California stocks seem to be somewhat sensitive to the NYMEX intertemporal price signal measured somewhat earlier.

Figure 2

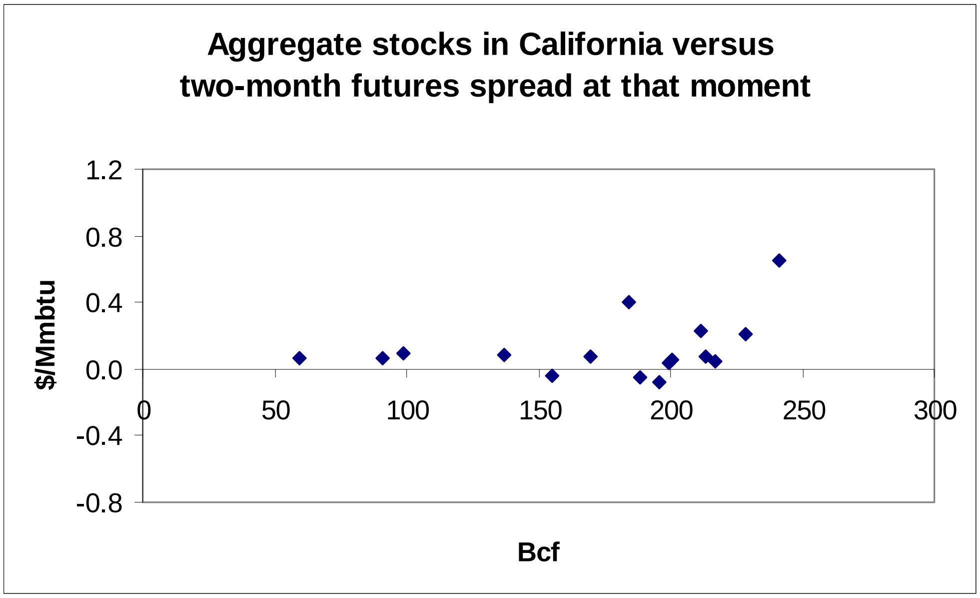
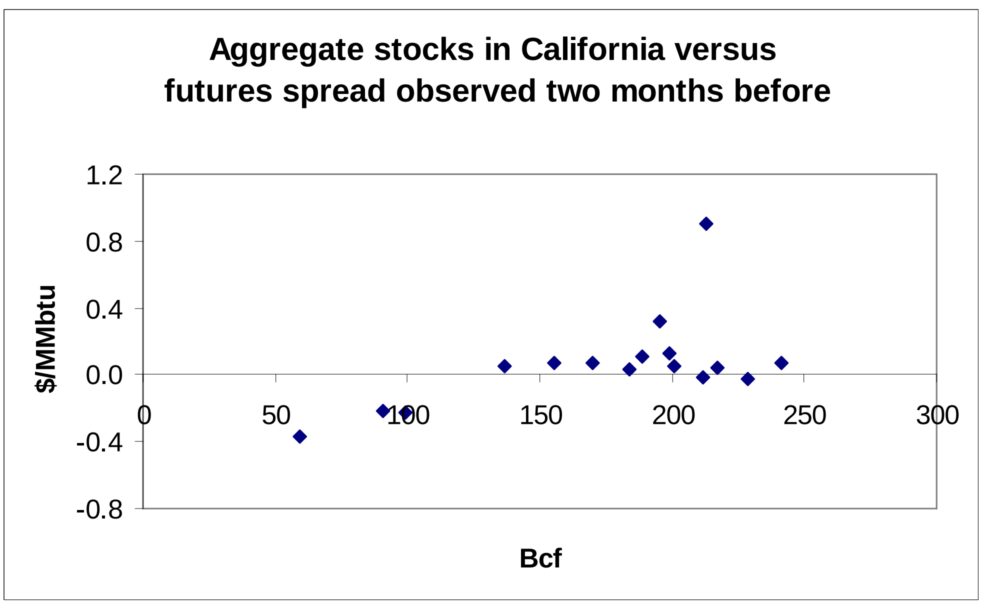


Figure 3



[18] In percentage terms, contangoes for natural gas can be much larger than for most other commodities. The one in fall 2004 was especially large, over $1.50 per MMBtu for two months of storage.

Two additional arguments provide support for the direction of causality suggested by Figures 2 and 3. First, storage capacity in California represents barely 3% of the U.S. total, which makes the assumption that California is a price taker of the NYMEX futures a reasonable one.[19] Second, information about the continuously posted NYMEX futures may inform day-to-day decisions on how much gas to put into storage. The Energy Information Administration (EIA) releases U.S. inventory reports on a weekly basis, which Linn and Zhu (2004) have shown have an effect on NYMEX futures prices. On a daily basis, inventory changes are likely to play only a small role in determining futures price spreads just because the information is not easily available at that frequency.

In order to explain the daily behavior of a group of California storage operators who can be considered NYMEX price-takers, it becomes sensible to pose the "supply-of-storage" relationship as one of spreads guiding injection decisions. Both the direction of causality and the choice of flows rather than stocks as the dependent variable differ from past literature.

Clearly, at least some information is gained from using daily injection data over the traditional analysis of monthly stocks versus spreads. Those gains are inversely proportional to the variability in the injection profile. If gas were placed into storage at a steady preset rate and pulled out so that the facility would be empty at the end of year, monthly injection or monthly stock data, even semiannual data, would be enough to understand storage behavior. Figures 4-7 illustrate daily net injection and stock profile for the four storage operations in California. Each figure has been scaled according to the inventory, injection, and withdrawal

[19] This argument further requires that weather shocks in California are not highly correlated with unusual weather in the main consuming regions further to the east, which correlation does seem low.

capacities of the facility so that they convey information about degree of utilization as well as about the variability in the series.

Figure 4

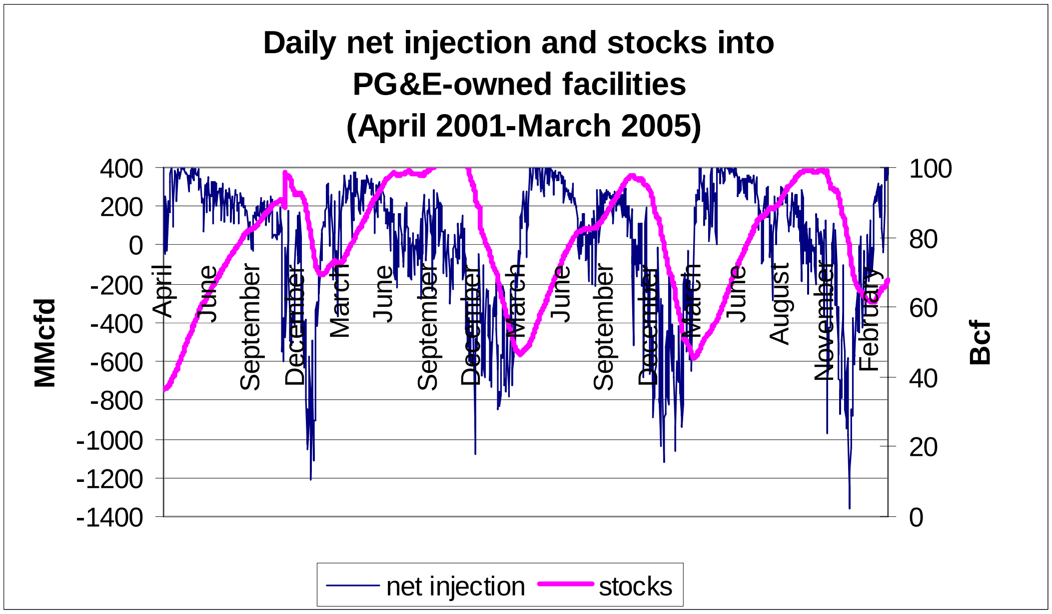


Figure 5

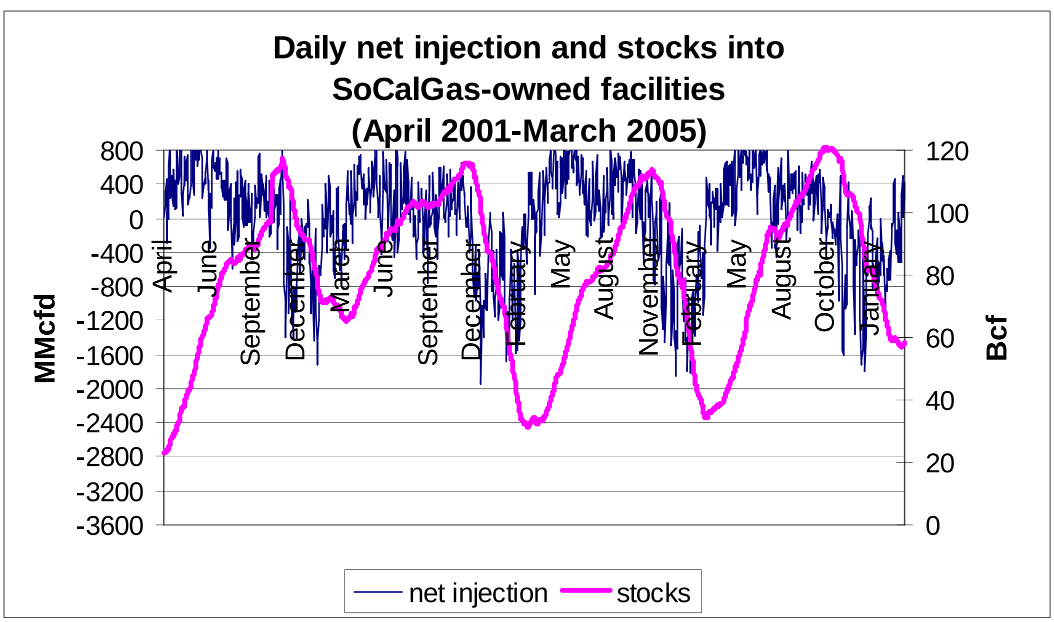


Figure 6

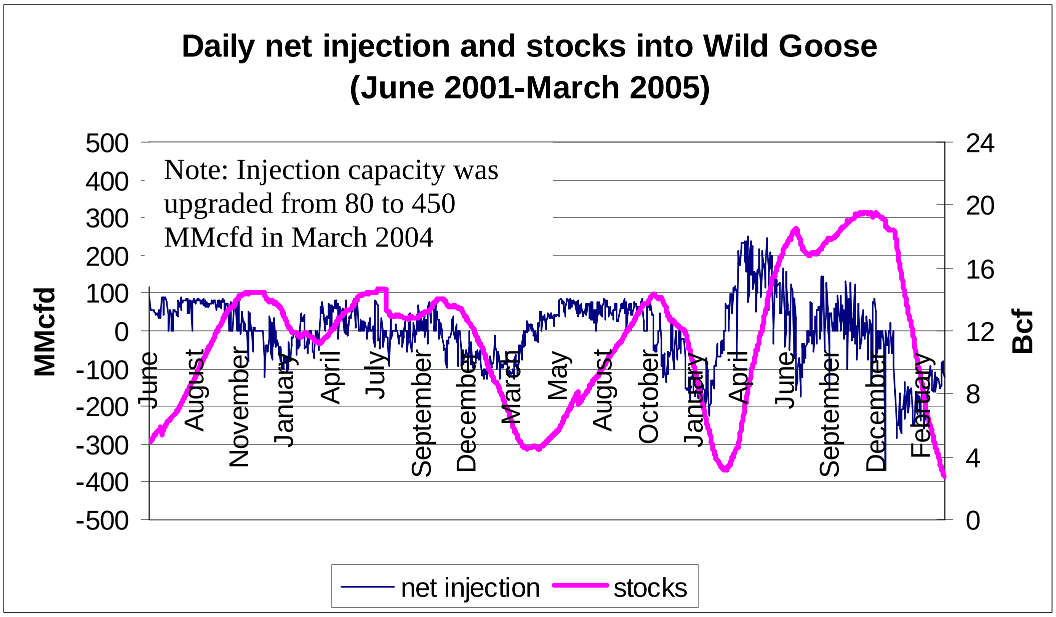
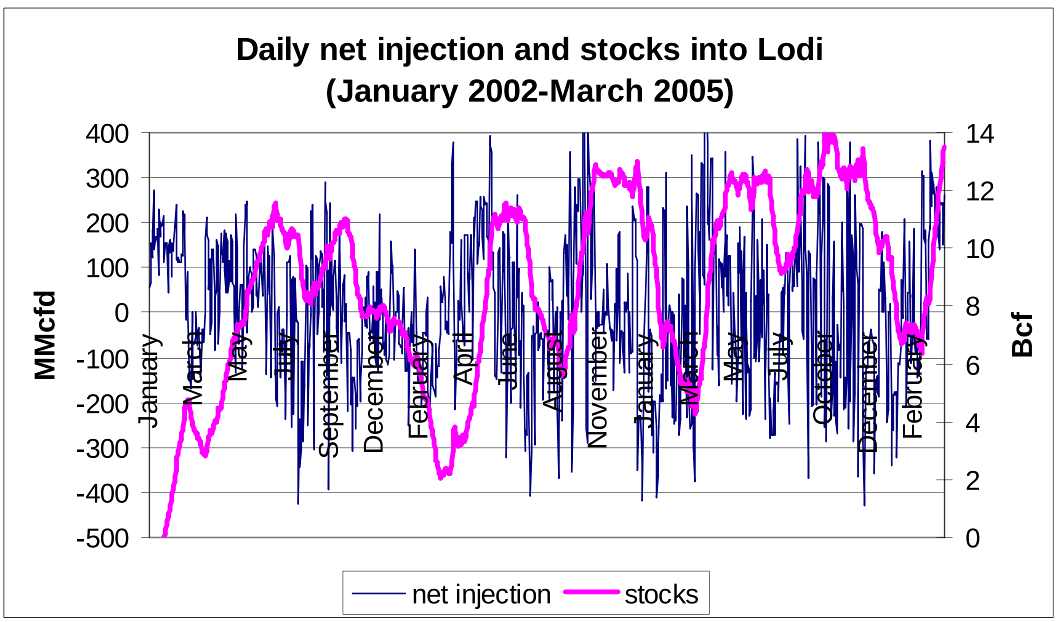


Figure 7



According to Figures 4-7, daily stock profiles are relatively smooth, their shape manifesting the strong seasonal demand cycle. Daily net injection, however, displays much more variability, most of which would be invisible if weekly or monthly figures were used. The seasonal cycle is discernible in the net injection series corresponding to PG&E, SoCalGas and Wild Goose, but not for the storage facility at Lodi, which switches continuously between injection and withdrawal. Less frequently, the other three facilities also switch modes of operation all through the year, so that the distinction between injection and withdrawal season is not clear cut. Figures 4-7 display enough variability to make the case for an econometric specification of injection decisions that contain variables besides a seasonal dummy.

Days on which gas is withdrawn during the official injection season or injected during the official withdrawal season give the most information about the relation of net injection and price spreads, since chances are that switches to a countercyclical behavior are in response to a price signal.[20] The percentage of countercyclical observations in daily data ranges from 14% for Wild Goose to 48% for Lodi. Such a percentage is smaller in weekly or monthly net injection series than in the daily ones. Thus, the level of temporal disaggregation matters when it comes to capturing these relationships. The detail within daily data is better exploited if the flow rather than the stock variable is the focus of analysis.

When flows (net injections) rather than stocks are used as the dependent variable, important implications result for the relevant intertemporal price spread. For instance, a flow on April 1, whether an injection or a withdrawal, is a forward-looking decision in

[20] Conversations with the storage operators have revealed that those switches are sometimes done for operational reasons like testing of the compressors.

response to the constellation of futures prices relative to all future dates observed that day. April 1 stocks, however, reflect to some degree the whole history of spreads relative to the futures contract for delivery that month, because they are the cumulative residual from previous flow decisions. The past literature has focused on highly aggregated data on stocks and has not paid much attention to the determinants of flows. Figures 8-11 plot daily net injection versus the spread per month observed each day (result of gas transactions that took place the day before) with respect to the futures contract for the beginning of the next season (either April or November). The strong seasonal cycle in natural gas demand makes price at the beginning and ending of the heating season a relevant benchmark for those taking storage decisions.

Figure 8

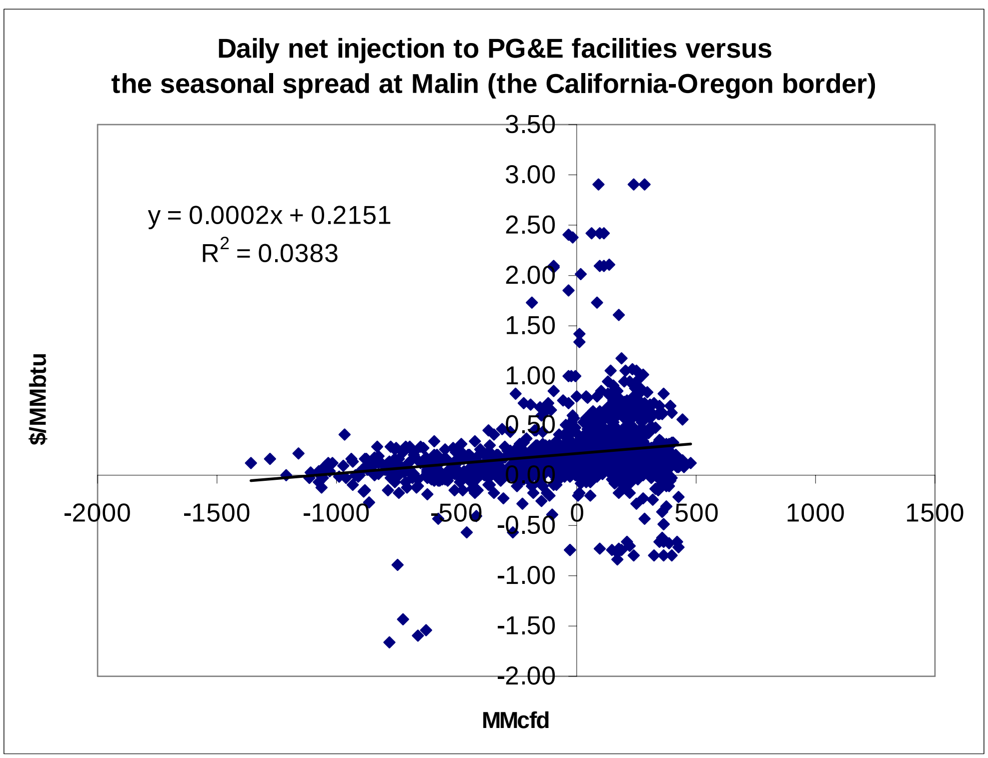


Figure 9

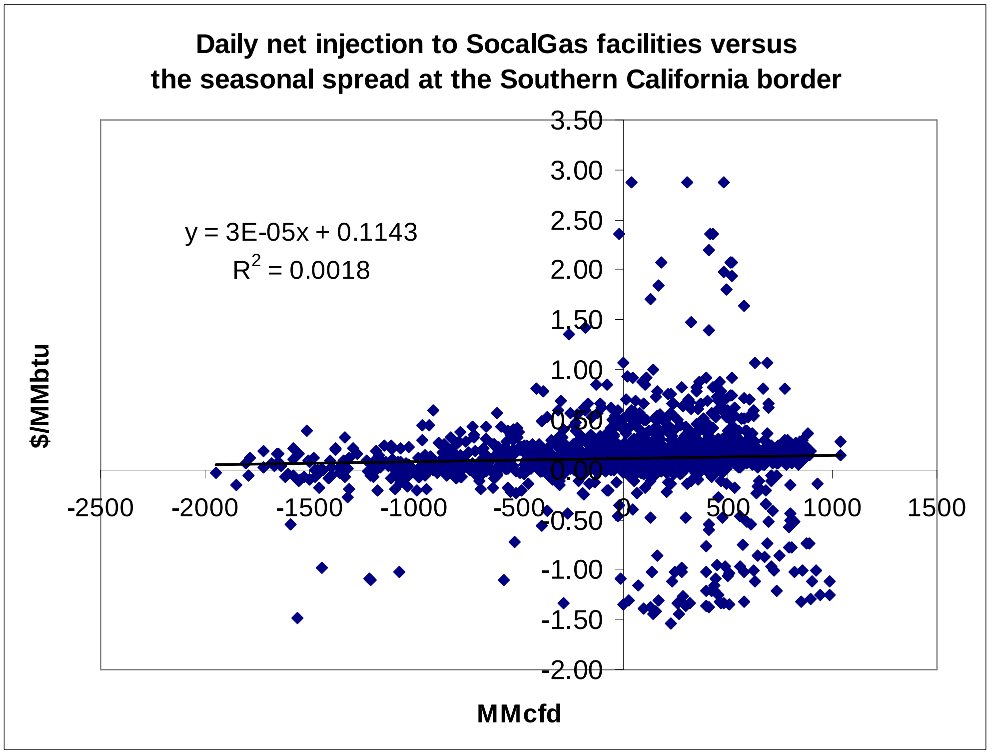


Figure 10

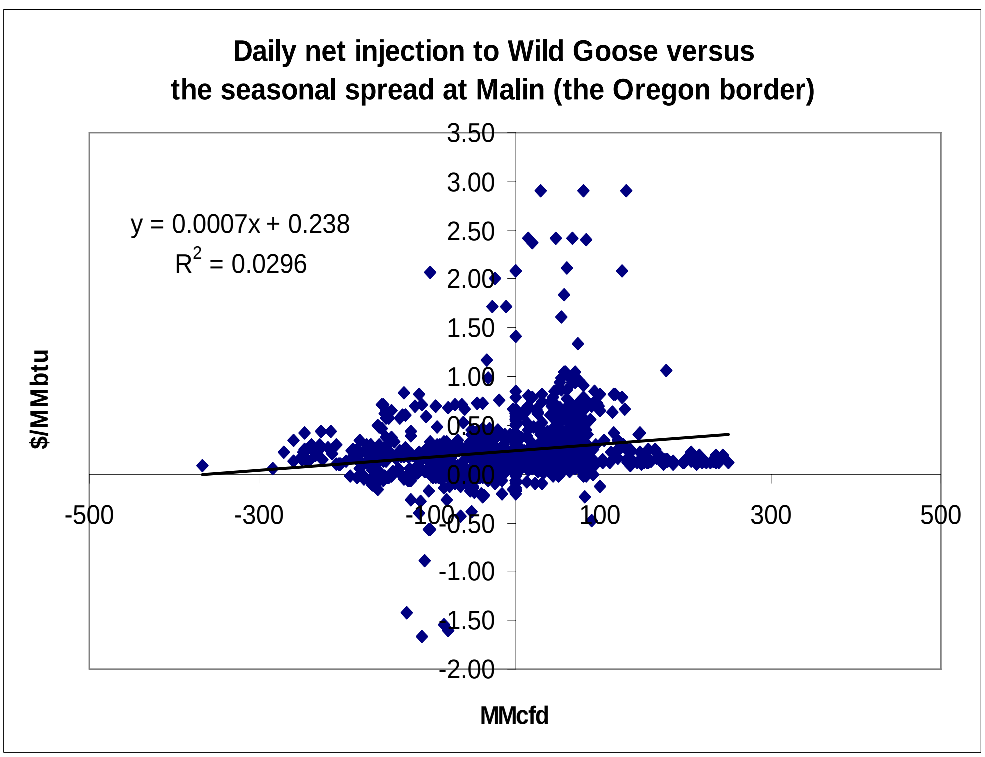
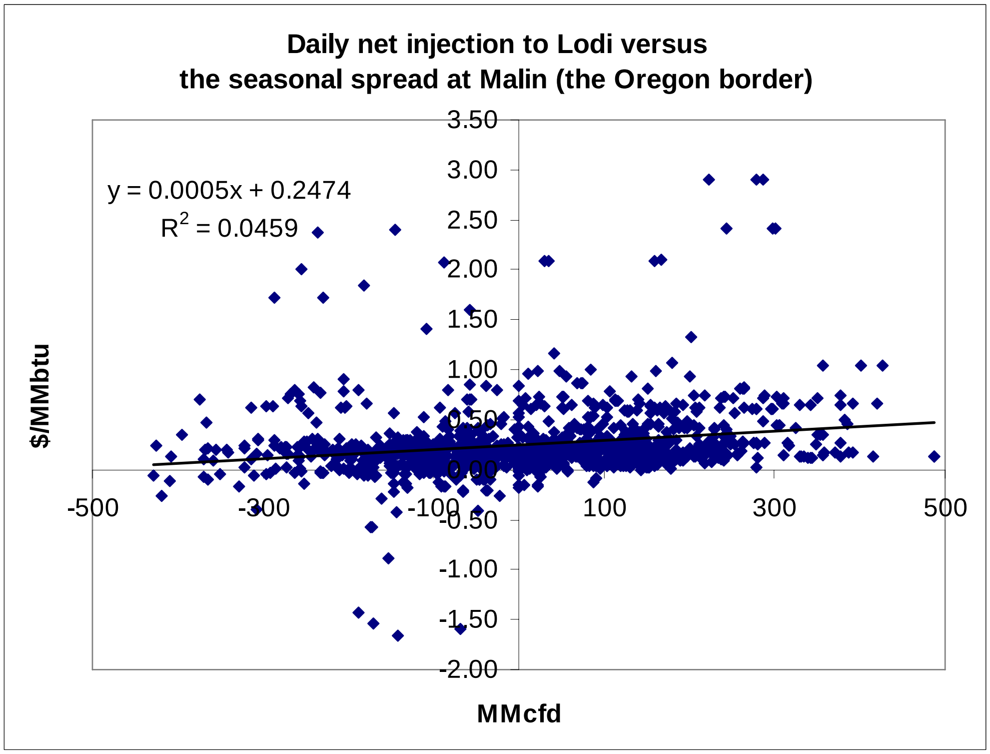


Figure 11



In Figures 8-11, points in the southeast quadrant violate the "supply-of- storage" theory.[21] Those points in the southeast quadrant mainly correspond to the first two months of the data set, during which the local spot prices in California were at historical maxima for a host of reasons resulting in the California "energy crisis".[22] Moreover, points in the southeast quadrant appear more often in the scatter diagrams for PG&E and SoCalGas. Because the stocks owned by PG&E and SoCalGas in April and May 2001 were well below the historical average and because it was the start of the official

[21] Clusters of points at the far right end of the quantity axis suggest that injection capacity is, at times, a binding constraint in PG&E, SoCalGas, and Wild Goose (for Wild Goose the constraint was relieved after its recent expansion). Withdrawal capacity does not seem ever to have been binding.

[22] Figures 8 and 9 for PG&E and SoCalGas contain data that span the longer period starting in April 2001 (data for Wild Goose start on May 22 of that year and Lodi started operation only in January 2002).

injection season, the utilities switched into injection mode even though the local spreads were in deep backwardation.

The intercept for the trendline fitted in each of Figures 8-11 provides, if the "supply-of-storage" theory is correct, a rough estimate of the monthly carrying charge at that facility. All intercepts, except the one corresponding to SoCalGas, are in the range of 20-25 cents/ MMBtu. Only for a contango of at least that magnitude would it be sensible to inject gas and hold it for a month. These four fitted intercepts are plausible, even if most observations are not close to the fitted line.

The slope of the fitted trendline informs about the strength of the relationship between the futures-spot differential and net injection at that facility. In all four cases, the trendline is nearly flat, suggesting a weak relationship. Conclusions about the strength of the relationship might change when other drivers of the net injection profile, such as the weekly cycle are taken into account.

4. SENSITIVITY TO SPREADS ACCOUNTING FOR OTHER INFLUENCES

As an indirect test of the "supply-of-storage" theory, the econometric analysis presented in this section asks whether natural gas injection decisions are tuned to futures price signals. To answer that question it is important to isolate the effects of price signals by controlling for other factors known to play a role in injection decisions.

The set of variables used to explain the net injection profile are listed in Table 2.

Lagged injection gauges the degree of inertia in the operation of the facility. The stock level describes the cost of additional injection. Day-of-week dummies and degree days characterize the day in terms of demand requirements while the operational flow

Table 2

List of variables for the econometric analysis

Dependent variable: ***net injection*** (MMcfd)
Regressors:
lagged injection: first lag of net injection series (MMcfd).
stock: beginning-of-the-day stock level (Bcf).
day-of-week dummies: interpreted with respect to Wednesday.
heating degree days (hdd): average temperature in the PG&E or SoCalGas system minus 65 degrees Farehnheit.
***cooling degree days (cdd)*:** 65 degrees Fahrenheit minus average temperature in the PG&E or SoCalGas systems.
***operational flow order (ofo)*:** 1 if the pipeline system is subject to an operational flow order, 0 otherwise.
***Henry Hub spread*:** NYMEX futures closing price for the seasonal or second to nearest contracts ($/MMBtu)- Henry Hub spot price[23]
basis: Malin (SoCalborder) daily spot price – Henry Hub spot price

order dummy accounts for pipeline operational constraints. The coefficients of interest to test the "supply-of-storage" theory are those on the intertemporal spread and locational basis. The price regressors are lagged one period, because information available at the time injection decisions are taken corresponds to the previous day. The contemporaneous local spot price (and thus the locational basis) is simultaneously determined with the storage and flow decisions but the lagged basis is a predetermined variable for which endogeneity does not constitute an issue.

Because the NYMEX natural gas futures market comprises 72 delivery months at any one time, there are as many simultaneous intertemporal signals. Which signal, if any, would be most relevant for flow and stock decisions in California? A further complication is that the local spreads shown in Figures 8-11 combine an intertemporal and a spatial element, each of which should be considered separately. The NYMEX futures – spot price at the Henry Hub reflects the pure carrying charge. The spatial

[23] Regressions were run also for the spread relative to the January futures contract and for the nearby and three-month spread but the results are not reported here.

element is reflected in the difference between the spot price at a California border and the spot price at the Henry Hub, which spatial spread contains information about the cost of transporting natural gas to some point in California, directly or indirectly. [24] On average, gas in Northern California is slightly more expensive than in Southern California and both cheaper than in Louisiana, although these patterns can be quite different on any one day. The positive mean locational basis displayed in Table 3 for Southern California results from extreme price peaks experienced in that location during the California energy crisis. The average locational basis starting as of June rather than April of 2001 is -0.20. The cost of transport to a particular location depends on how congested the pipelines are and how the prices of gas in California and Louisiana compare at any one moment.[25] Such separation is not just an artificial construct. In this context, the basis swap contracts offered by NYMEX at Malin and SoCal are worth considering, for they provide protection from basis risk and allow taking advantage of spatial arbitrage opportunities. A combination of NYMEX futures and basis swaps constitutes the closest substitute available for a California forward contract.

Given that there is an official storage season for each operation mode (i.e., injection and withdrawal), it makes sense to look at the futures contracts associated with their start (April and November). The "seasonal" spread, as used here in Table 4, is constructed as the difference between the closer to expiration of the April and November NYMEX futures contracts and the spot price at Henry Hub. The "seasonal" spread is then adjusted by dividing it by the number of months until expiration so that it refers to

[24] The daily spot price at a given location is the average price from a survey of transactions involving gas to flow the next day. Most natural gas, however, is traded during the last five business days of each month (bidweek) to flow the following month. The average price from those monthly trades is the bidweek price.
[25] Transportation also involves time, but the time involved for moving natural gas distances is measured in days rather than months.

the storage return per month. Another possibility, as reported in Table 4, is an adjusted two-month spread. Intuitively, at any one date, the spread per month associated with different futures contracts should be approximately the same; otherwise, there would be arbitrage opportunities not being exploited.

Table 3

Descriptive statistics about locational basis

Basis $/MMBtu	mean	standard deviation	minimum	maximum
Malin spot - Henry Hub spot	-0.32	0.83	-8.94	5.99
SoCal border average spot – Henry Hub spot	0.14	1.78	-9.31	10.30

Table 4

Descriptive statistics about intertemporal price spreads

Spread (per month) $/MMBtu	mean	standard deviation	minimum	maximum
2-month NYMEX futures- Henry Hub spot	0.06	0.34	-6.13	1.84
Season-long NYMEX futures-Henry Hub spot	0.15	0.28	-6.13	1.55

Table 4 reveals striking differences in the mean spreads per month when the two-month and season-long intervals are compared. The differences can be explained by the demand jump in November as residential customers switch on their heaters. That expected jump in demand translates into a higher-than-otherwise price for the underlying futures contract as well. Thus, the descriptive statistics of the intertemporal spread are sensitive to the chosen expiration month. More important, to the extent that the intertemporal signal tracks the futures profile, positive correlation between net injection and an intertemporal signal can be induced just by using the “right” length of spread. NYMEX natural gas futures increase April through January, although more strongly between November and January, and then decline until the beginning of the next injection season. The two-month spread will peak September through November because, during that interval, it refers to the highly priced winter month contracts. On the other hand, September through November is not customarily a heavy injection period. Therefore, evidence about price responsiveness using the two-month spread reflects something other than coinciding seasonal peaks in injection flows and spread.

As extreme as are some contangoes observed during these four years, even more extreme are the backwardations. The asymmetry in the distribution of prices has its flip side in an observation that can be made for Figures 4-7 (Bresnahan and Spiller, 1986): Injection capacity is used sometimes at its maximum (stopping the contango from deepening too much) but withdrawal capacity is not used similarly to limit the extent of backwardation with respect to the local spot price. Bottlenecks in pipelines and regulatory requirements are plausible explanations for why withdrawal capacity is not used more heavily in response to backwardations.

Natural gas flows in and out of storage continuously, whereas prices are only generated during business days. According to industry convention, the price that applies to storage flows during weekends and holidays is that from the previous business day. The industry’s pricing convention allows the analysis here to equalize the length of the physical flows and price series but also alters the structure of the latter. Both daily injection and daily spreads are highly autocorrelated. The repetition of prices over weekends will increase the autocorrelation in the spread series. For the spread series, the hypothesis of a unit root can be rejected at the 1% level in all cases (such result is robust to the assumption made about non-business days). The stock level series present strong evidence of the existence of unit roots. The correlograms of the net injection series show strong first-order autocorrelation but the null hypothesis of a unit root can be rejected at the 5% significance level. The inclusion of the lagged dependent variable as a regressor corrects for autocorrelated errors and weakens the significance of the spread variables.

Table 5 summarizes the results from regressing net injection in each facility on the set of variables described in Table 2.

According to the R-squares in Table 5, the chosen set of regressors explains most of the variability in net injection, although least for Lodi. The negative and significant relationship between the current stock level and the day's net injection at all four facilities captures the nonlinearity in injection costs: When the storage reservoir is nearly full, additional injections become increasingly costly in terms of needed compression power. All facilities reveal a similar weekly cycle with injection peaking on Saturday and reaching a low Monday in the utility-owned facilities and on Tuesday in the independent facilities.[26] Competition for pipeline space between gas for storage and gas for consumption is a likely explanation for this weekly cycle, as industrial and electricity generation demand is higher on business days.

In a structural model of flow and storage decisions taken on the natural gas transportation and distribution network, degree days would appear on the right-hand-side of the demand equation. The regressions reported in Table 5 are better interpreted as a reduced-form model in which degree days are used as a proxy for the seasonal cycle in demand.[27] A scatter plot of net injection versus heating and cooling degree days shows a

[26] Often, customers of the independent facilities make deals on Friday for gas flows in Saturday, Sunday and Monday. That may explain why Tuesday behaves as the beginning of the business week for Wild Goose and Lodi.

[27] An injection-season dummy that takes the value 1 from April through October was eliminated from the model as it becomes insignificant with the inclusion of degree day variables.

Table 5

Estimated coefficients from OLS regressions of daily net injection by facility on lagged intertemporal spread and lagged locational basis

	PG&E		SoCalGas		Wild Goose[28]		Lodi	
	seasonal	2-month	seasonal	2-month	seasonal	2-month	seasonal	2-month
R^2	0.888	0.885	0.880	0.88	0.856	0.855	0.567	0.568
D-W statistic[29]	2.00	2.05	1.80	1.80	2.11	2.11	2.06	2.06
lagged injection	**0.761** (52.03)[30]	**0.760** (46.91)	**0.732** (49.27)	**0.732** (49.35)	**0.803** (46.57)	**0.804** (46.42)	**0.624** (28.41)	**0.623** (28.44)
stock	**-0.907** (-4.59)	**-1.139** (-4.59)	-0.264 (-1.11)	**-0.447** (-1.75)	-0.325 (-1.39)	**-0.370** (-1.56)	**-5.513** (-4.88)	**-6.739** (-5.20)
Thursday	-13.242 (-1.18)	-18.571 (-1.42)	**31.815** (1.63)	**31.512** (1.612)	2.050 (0.70)	2.123 (0.725)	16.705 (1.43)	16.302 (1.40)
Friday	13.703 (1.22)	10.228 (0.78)	**121.73** (6.22)	**122.26** (6.24)	0.587 (0.20)	0.721 (0.24)	**40.072** (3.42)	**39.926** (3.41)
Saturday	**33.133** (2.93)	**28.829** (2.19)	**232.44** (11.65)	**234.31** (11.74)	**7.659** (2.58)	**7.939** (2.68)	**104.27** (8.89)	**104.16** (8.89)
Sunday	**-21.870** (-1.93)	**-26.940** (-2.04)	**84.454** (4.18)	**85.431** (4.23)	0.587 (0.19)	0.838 (0.28)	**57.523** (4.81)	**57.359** (4.80)
Monday	**-63.837** (-5.64)	**-69.460** (-5.25)	**-275.30** (-13.67)	**-276.28** (-13.72)	1.617 (0.54)	1.715 (0.58)	**45.554** (3.79)	**44.921** (3.74)
Tuesday	-10.699 (-0.95)	-12.792 (-0.97)	23.966 (1.22)	23.705 (1.210)	**-12.534** (-4.26)	**-12.843** (-4.24)	**-44.562** (-3.73)	**-44.865** (-3.76)
hdd	**-12.214** (-14.09)	**-13.360** (-13.30)	**-34.453** (-17.63)	**-35.138** (-17.95)	**-1.454** (-7.38)	**-1.535** (-7.95)	**-2.345** (-3.49)	**-2.728** (-4.26)
cdd	**-5.199** (-6.51)	**-5.759** (-5.93)	**-12.527** (-9.13)	**-11.839** (-8.61)	-0.306 (-1.58)	**-0.290** (-1.47)	**-2.299** (-2.71)	**-1.999** (-2.32)
OFO	-1.306 (-0.14)	-4.545 (-0.39)	**-149.89** (-7.03)	**-158.51** (-7.31)	**9.748** (3.72)	**9.659** (3.68)	**89.590** (8.85)	**86.344** (8.43)
lagged seasonal spread	**30.275** (2.51)		**76.178** (3.69)		**9.555** (2.45)		**33.927** (2.55)	
lagged 2-month spread		**25.472** (2.11)		**66.707** (3.64)		**6.759** (1.90)		**35.930** (2.97)
lagged locational basis	**10.711** (2.67)	**24.715** (2.56)	**10.685** (3.20)	**10.195** (3.03)	-0.152 (-0.07)	0.920 (0.44)	**-26.259** (-2.81)	**-29.385** (-3.09)
Constant	**183.40** (9.82)	**223.15** (9.43)	**180.90** (7.28)	**193.30** (7.53)	**12.994** (3.43)	**14.086** (3.75)	20.086 (1.43)	**29.136** (2.06)

[28] For Wild Goose, a Chow test indicates that the hypothesis of equal coefficients in the pre-expansion and post-expansion periods must be rejected. The results in Table 5 correspond to the pre-expansion period. Figure 6 showed that injection capacity was often binding at Wild Goose before the upgrade that came online in April 2004.

[29] The relevant upper and lower bounds of the Durbin-Watson statistic are 1.35 and 2.03. Thus, the null hypothesis of no autocorrelation will not be rejected for Wild Goose and Lodi. Meanwhile, results for the utility-owned facilities lie in the inconclusive region of the test.

[30] t-statistics are in parentheses. Estimated coefficients whose t-statistic is above 1.66 are significant at the 5% level and bolded.

strong relationship, one close in shape to an inverted parabola. Even so, temperature does not cause flows into or out of storage directly, but indirectly through demand.

Extreme cold or hot temperatures in California increase demand for natural gas, which is partly satisfied by bringing into the system additional flows from outside the state and partly by making withdrawals from in-state storage. For the utility-owned facilities, inventory withdrawals are heavier in response to demand for heating than for cooling. Lodi's exception to the pattern is explained by its serving electricity generators, which makes the effects of unusually hot weather and unusually cold weather similar.

According to the estimates in Table 5, OFOs trigger different responses across the four storage facilities in California. PG&E-owned facilities do not respond to OFOs. SoCalGas customers withdraw gas under OFOs. Customers holding capacity in the two independent storage facilities in the PG&E region inject gas to help balance their accounts with the pipelines. The opposite sign for SoCalGas versus the independent facilities in Northern California implies that in the southern system, flows from out of state are reduced in response to an OFO while storage withdrawals compensate for that pipeline inflow reduction. In contrast, customers of independent facilities in Northern California appear to be moving the gas that they had "parked" in the PG&E pipelines into storage to reduce the pipeline load factor.[31] More broadly, OFOs are an example of an operational constraint that could be muffling responses to intertemporal price signals from the futures market.

In the context of these effects of weather and operational constraints, it remains to discuss the effect of price signals. In accord with "supply-of-storage" theory, the

[31] "Parking" is short-term storage of gas at selected locations in the pipeline system. Parking transactions are attractive because they do not involve injection or withdrawal fees but the system operator can ask for the gas to be unparked any time the pipeline becomes congested.

intertemporal spread per month has a positive effect on the amount of gas placed into every facility in California. The estimated coefficients on the intertemporal spread are such that a 1.00 $/MMBtu increase in the spread (a substantial change considering the range reported in Table 4) would increase injection by approximately 10% of injection capacity in any of the facilities, either utility-owned or privately operated.

As for the locational basis, the effect is smaller but still significant for all facilities, except Wild Goose. For the utility-owned facilities, the estimated coefficient on the basis is positive, which would be consistent with the idea of gas flowing towards the network hubs in which it is most valuable at the time. For Lodi, the estimated coefficient on the locational basis is negative, which may be because customers at this facility are primarily electricity generators. In summer, which happens to be the season in which the relative value of natural gas in California versus the Henry Hub is highest, the need for electricity generation peaks.

In sum, according to the evidence in Table 5, injection/withdrawal decisions, and by implication, storage decisions are made in California with an eye to profitable arbitrage opportunities, even though preset seasonal and weekly cycles largely determine the injection profile and regulatory requirements and operational constraints limit the size of the response.

5. EFFECTS OF SPATIAL AND TEMPORAL AGGREGATION

Results from the daily analysis of individual storage facilities reveal sensitivity, albeit weak, to intertemporal price signals. When the same relationship is aggregated over facilities and examined at more widely separated times, the gains provided by the disaggregate analysis can be ascertained more clearly. Indeed, it can be determined whether a more aggregated analysis gives a misleading impression of the sensitivity of storage within California to NYMEX prices.

Spatial aggregation

Natural gas inventory figures are reported mainly at the regional or state level. Net injections are usually not reported but could be constructed easily from information about stocks. To investigate the relationship between net injection in California and spreads, summary measures of the prices and temperatures across the state must be constructed. Price spreads and measures of degree days for the aggregate California injection were constructed here as weighted averages of the separate series for the PG&E and SoCalGas systems. The weights given to locations are based on the percentages of total flows that use Malin and the SoCalborder average as the reference price respectively. The weights on degree days were based on the percentage of total demand that each region represents. Lagged injection, aggregate stock level, and day-of week dummies were included as well. However, the OFO dummy was excluded, because it is specific to each pipeline system. Table 6 focuses on the effect of price spreads on aggregate net injection.

Table 6

Estimated coefficients with California-wide daily net injection

(other variables not shown)

Dependent variable: California net injection	seasonal	2-month
lagged Henry Hub spread	**77.589** (2.69)	**66.227** (2.59)
lagged locational basis	**18.104** (2.81)	**17.631** (2.72)
R^2	0.923	0.923

According to Table 6, the response in the aggregate is smaller than that observed in the regressions for individual facilities. One-dollar increases in either the intertemporal or spatial spreads result in increases in daily injection that represent 3.8% and 0.9% of the state's injection capacity respectively. The estimated coefficients on stock, day-of-week dummies and degree days replicate the results seen for the utility-owned facilities in Table 5 because they make up for 85% of storage capacity in the state. Similarly, the results from considering jointly the three facilities sharing PG&E's pipeline infrastructure resemble closely those from PG&E-owned facilities. In general, the estimated coefficients for the California aggregate are not the weighted sum of the individual coefficients. The behavioral differences between utility-owned and privately-owned facilities, which can be important in managing network operations efficiently and in designing optimal regulatory rules, are lost in models that look at aggregate storage over all of California.

Temporal aggregation

Measurement at intervals longer than a day may also mask the behavioral differences across types of facilities. The results in Tables 7 and 8 correspond to a set of regressions in which weekly and monthly net injection in California facilities are a function of net injection over the previous interval, stock level at the beginning of the interval, cumulative heating and cooling degree days, and weekly or monthly average price spreads. Price spread variables refer to the same period as injection because the temporal ordering of variables cannot be discerned anymore. Day-of-week and OFO dummies are left out.[32]

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[32] The estimated coefficients from the weekly and monthly regressions were divided by 7 and 30 respectively so that they all represent a daily effect.

Table 7

Estimated coefficients with California weekly net injections

(other variables not shown)

Dependent variable: weekly net injection	PG&E		SoCalGas		Wild Goose		Lodi	
	seasonal	2-month	seasonal	2-month	seasonal	2-month	seasonal	2-month
Henry Hub spread	**86.566** (1.79)	**92.444** (3.112)	**259.98** (3.78)	**196.97** (3.89)	**17.789** (2.07)	**12.274** (1.88)	**72.113** (1.75)	**79.377** (3.03)
locational basis	**22.776** (2.41)	**20.530** (2.21)	11.705 (1.02)	9.236 (0.80)	-1.411 (-0.24)	-1.031 (-0.18)	-29.266 (-1.26)	**-46.193** (-1.97)
R^2	0.880	0.880	0.835	0.836	0.874	0.874	0.485	0.500

Results in Table 7 for weekly flows differ considerably from those with daily data. On one hand, weekly injections increase as the magnitude of the contango in the weekly average intertemporal spread does. The magnitudes of those injections, even though they are adjusted to represent daily effects, are significantly bigger than those in Table 5 (and the bigger magnitude persists even when compared with daily regressions in which the day-of-week and OFOs dummies are left out). On the other hand, only PG&E facilities seem to be paying attention to the differential between the local and Henry Hub spot prices. Such a contrast can be explained by the weekly cycle followed by the locational basis series. The basis is significantly higher on Monday than on Wednesday and significantly lower on Friday than on Wednesday. This weekly pattern is hidden in the weekly average. The estimated coefficients on stock level and degree days continue to be negative and significant for all four facilities.

Table 8

Estimated coefficients with California monthly net injections

(other variables not shown)

Dependent variable: monthly net injection	PG&E		SoCalGas		Wild Goose		Lodi	
	seasonal	2-month	seasonal	2-month	seasonal	2-month	season al	2-month
Henry Hub spread	76.026 (1.51)	22.87 (0.54)	61.466 (0.97)	-33.507 -(0.80)	11.366 (0.89)	12.583 (1.17)	61.467 (1.57)	**53.403** (1.665)
locational basis	-4.766 (-0.39)	-1.516 (-0.12)	-11.020 (-1.50)	-9.855 (-1.26)	3.804 (0.20)	2.611 (0.138)	-4.267 (-0.12)	-13.903 (-0.35)
R^2	0.872	0.867	0.892	0.891	0.799	0.801	0.529	0.519

With monthly data, as in Table 8, responsiveness to price signals vanishes as short-term switches from injection to withdrawal and *vice versa* cancel out. The following example illustrates well the loss of information entailed when aggregating data to this extent. In November 2001, average injection in PG&E-owned facilities in November 2001 was minuscule (-4.81 MMcfd) and all the price spreads considered were in contango at that time. However, daily data shows that injections took place for the first three weeks of that month (as it would be expected in response to a contango) and were followed by heavy withdrawals in the last week of the month, withdrawals that offset almost entirely the initial injection.

Different aspects of the net injection - spread relationship appear more important depending on the level of temporal aggregation used. Monthly data mostly capture the seasonal profile of storage flows, which is ultimately driven by seasonal demand requirements and which appears particularly sensitive to the length of the spread considered. Weekly data acknowledge the regularities in pipeline and storage operations at that frequency but still hide intraweek dynamics brought about by a trough in demand requirements during the weekend. Daily data by facility allow a more stringent test of responsiveness to price signals, because the sequence at which price information becomes available and decisions are taken becomes identifiable, and because additional factors affecting net injection decisions such as operational flow orders or extreme weather events can be accounted for.

The most disaggregate analysis would involve customer-level data at each facility for each nomination cycle, and the daily adjustments.[33] Such level of detail would result in a collection of individual "supply-of-storage" curves, which would be valuable for designing optimal scheduling rules and storage tariffs. The number and type of customers responding to intertemporal price signals could be determined precisely.

6. CONCLUSIONS

Multiple cycles of different frequencies rather than a simple "supply-of-storage" curve can be discerned in day-by-day stocks of natural gas. A seasonal cycle driven by demand and regulatory requirements, a weekly cycle that follows the dynamics of pipeline load, and daily adjustments to weather and operational conditions all influence storage injection and withdrawal decisions. The "supply-of-storage curve" proposed by Working may work so well for wheat because the seasonal cycle so dominates. The question for natural gas is whether injection decisions (rather than the resulting stock level) respond to short-term arbitrage opportunities despite official seasons, regulatory requirements, and operational rigidities.

[33] There are four nomination cycles during which a customer may adjust the amount of gas he wants to place into storage. The first two nomination cycles happen the day before the gas is scheduled to flow; the other two are intraday adjustments.

The need for highly disaggregated data to carry out meaningful analysis of flows might explain why most of the literature on the “supply-of-storage” restricts itself to data about stocks. An exceptional data set allows an investigation of daily flows in the four California storage facilities after controlling for the factors governing the lower frequency cycles. Daily data by facility mimic best the actual decision sequence and reveal that injection in California facilities increases slightly as the intertemporal spread on NYMEX strengthens.

A useful extension could be the closer examination of the determinants of switches between injection and withdrawal decisions observed in daily flows, perhaps by means of a threshold regression model. A structural, simultaneous equations system would be necessary to fully comprehend the daily interactions of demand, flow, and storage decisions, inevitably linked by the material balance equation that must hold in the network. Finally, it would be interesting to compare the California case with some other area closer to the Henry Hub to see how much does distance mute the price signals implied by the NYMEX futures price spreads.

Storage decisions in California do seem to be influenced by intertemporal price signals on a futures market, but the magnitude of the effect is small and depends on the specifics of the various cycles and the nature of the storage facility. Time and space both matter, but not in a simple way.

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