California Energy Commission

STAFF REPORT

ESTIMATING BURNER TIP PRICES, USES, AND POTENTIAL ISSUES

CALIFORNIA
ENERGY COMMISSION

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ABSTRACT

Natural gas burner tip prices represent the cost of gas for a natural gas-fired electric generator. Burner tip prices include both a commodity and a transportation component. The commodity component is the price of the natural gas at a price hub (Henry Hub, for example). The transportation component is the cost of transporting the gas from a given price hub or basin to the electric generator for consumption.

Estimated future burner tip prices are used for electricity resource planning. The cost of fuel to run an electric generator is a major component of the overall cost of running an electric generator. These fuel costs will affect long-term decisions on the types of electric generation and infrastructure that are built.

The method for estimating burner tip prices is based on forecasted annual natural gas commodity prices from the World Gas Trade Model and transportation rates from interstate, intrastate, and utility level transportation rates. The annual forecasted natural gas commodity prices are first converted to monthly values. Then, the appropriate transportation rate (tariff) is added to account for transportation to the electric generator.

There are some potential uncertainties when estimating burner tip prices. Environmental regulations, changes in supply and demand, and the price of alternative non-fossil fuels will affect the future commodity price of natural gas. The cost of transporting natural gas may change based on environmental policies, pipeline infrastructure additions and repairs, and shifts in supply and demand.

Keywords: Natural gas, prices, burner tip, forecasts

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EXECUTIVE SUMMARY

Natural gas burner tip prices are technically defined as the price paid for natural gas that is burned at a furnace, water heater, natural gas-fired electric generator, or another end use. For purposes of this report, burner tip prices will refer to the amount that natural gas power plants pay for fuel (natural gas) to burn at a gas-fired generator to generate electricity. These burner tip prices include not only the cost of the gas itself (the commodity price), but transportation charges as well. The level of future burner tip prices will help system planners understand the implications of relying on natural gas-fired electric generation and the associated need for electric transmission lines and natural gas pipelines, storage facilities, and other infrastructure.

This paper provides transparency to the California Energy Commission's method for estimating burner tip prices. Having a transparent burner tip price estimation method will allow feedback from stakeholders and the ability to improve the Energy Commission's method over time. Other models, such as the PLEXOS production cost model and the Cost of Generation model, can use the burner tip price estimation methods to develop burner tip prices as inputs. Other agencies, such as the Western Electricity Coordinating Council, may find use in the Energy Commissions methods in their own burner tip price modeling.

The Cost of Generation model is a spreadsheet model that calculates the total costs of building and operating a power plant over its economic life and converts the total costs to equal annual payments in dollars per megawatt-hour and dollars per kilowatt-year. The annual costs provide a basis for comparing the total costs of one power plant to another. The burner tip price is a major cost driver for natural gas power plants. The PLEXOS production cost model is a commercial power market modeling and simulation software. This model is an analytical representation of the electrical grid serving the western United States that is able to calculate the costs of operating the electric system, including generator operating costs, transmission costs and the costs of various constraints that arise in operating such complex systems.

This report examines the method and techniques the Energy Commission uses to estimate natural gas burner tip prices for various electricity system planning models. The period for these estimates generally goes out 30 years (through 2030). This paper also examines burner tip price estimation methods employed by other entities, such as the California Public Utilities Commission (CPUC) and the Western Electricity Coordinating Council. End-use burner tip prices are estimated on a monthly basis by developing and applying monthly seasonal factors from historical natural gas commodity price patterns. This annual-to-monthly conversion is described in this paper, including uncertainty in natural gas commodity price forecasts going forward.

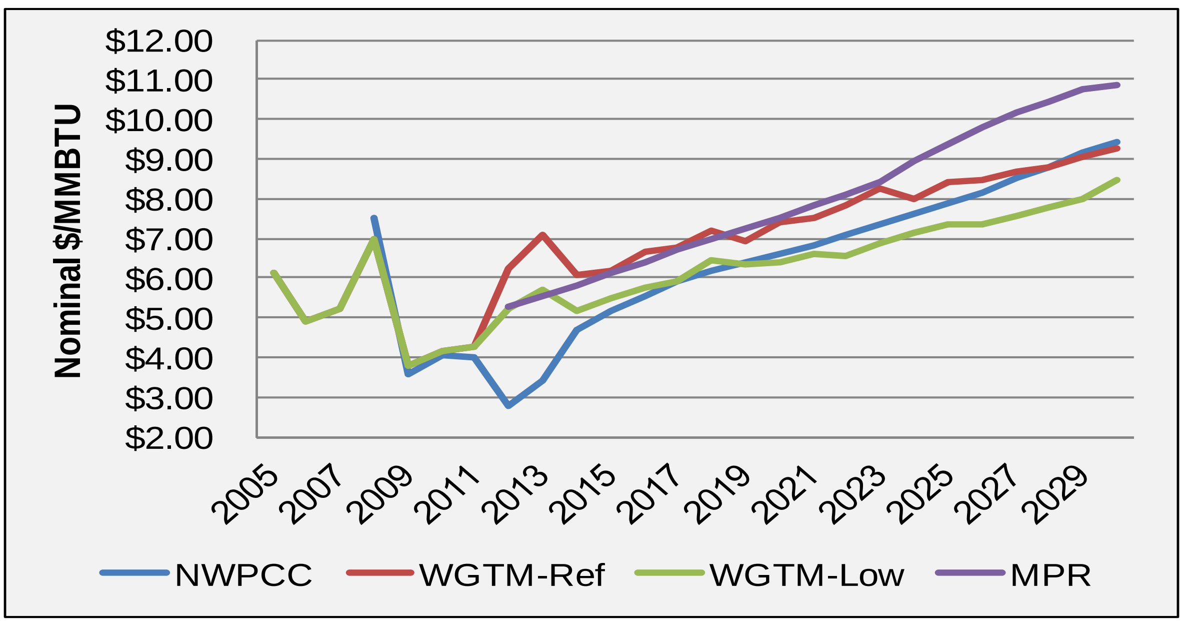
The Energy Commission uses both interstate and intrastate (utility transmission and distribution) natural gas pipeline rate information to estimate the cost of transporting natural gas to natural gas-fired electric generators. The transportation rates will vary depending on customer class and the rate structure for each pipeline or natural gas utility.

Over the long run, transportation rates generally both increase and decrease, although with no set pattern.

Future work may include running various sensitivities on the Energy Commission burner tip price estimates. These sensitivities will entail allowing transportation rates to change over time as well as using basis swaps and other methods for transportation costs rather than interstate pipeline tariffs. A basis swap is an agreement between two parties that pays one party the price difference (which may vary) between two price locations and pays the other party a fixed amount. In theory, the price difference between two price locations measures the cost of transportation between the two price points. Other sensitivities may be run on the commodity price forecast also.

Next steps include vetting this paper with interested stakeholders such as the Western Electricity Coordinating Council, the gas utilities, merchant gas-fired generators, other load-serving entities, and the interstate pipeline companies. Getting stakeholder feedback can help staff refine the method for estimating burner tip prices. Some of the stakeholder feedback may include forecasts of transportation rates, as well as more information on how natural gas is procured.

Figure 1: California Burner Tip Price Estimates



Source: Northwest Power and Conservation Council, 2011 CPUC Market Price Referent, and Energy Commission staff analysis.

Overall, the Energy Commission's burner tip price estimates appear reasonable when compared to other estimates. The natural gas commodity price forecasts associated with Northwest Power and Conservation Council's estimates and the *California Gas Report* burner tip prices have similar assumptions to those of the Energy Commission's natural gas commodity price forecasts. As previously discussed, the treatment of transportation rates in estimating burner tip prices differs among methods. The Energy Commission uses natural gas pipeline and utility pipeline tariffs, while other methods use financial basis swaps or historical natural gas regional price differentials.

The Energy Commission's current method may need to be updated as the natural gas industry changes with respect to supply, demand, natural gas infrastructure, natural gas procurement strategies (short-term vs. long-term natural gas purchases), environmental policies, and other pertinent factors. The natural gas utilities and pipeline companies can also provide the Energy Commission with new information on how natural gas is procured and transported.

Keeping the Energy Commission's burner tip price method up to date will provide staff with insights on how natural gas is purchased and used for electric generation; electricity system planners will also gain insights from understanding how natural gas burner tip prices are used and the factors that affect them. Performing these burner tip price estimates regularly, each *Integrated Energy Policy Report* cycle for example, will help keep the Energy Commission's methods and assumptions up to date.

CHAPTER 1: Introduction

A full technical definition of a burner tip price is the price paid for natural gas that is used at a furnace, water heater, natural gas-fired electric generator, or other end use.[1] In this report, burner tip prices mean the price paid for natural gas at a natural gas-fired electric generator. The natural gas has reached its final destination, and the price of this natural gas includes all transportation charges and commodity costs such as the finding costs, processing costs, and so forth. Burner tip prices can change because of movements in the commodity cost of natural gas (the price of the gas itself) and movements in the costs to transport natural gas. Fuel costs are a significant component of the variable operating cost of a gas-fired generator. The cost of transportation is the cost of moving natural gas from where it was purchased to its end use. Natural gas transportation costs are referred to as *natural gas transportation rates* in this paper. Transportation rates are approved by the Federal Energy Regulatory Commission (FERC) for interstate natural gas pipelines and by the California Public Utilities Commission (CPUC) for intrastate pipelines/natural gas utility distribution and transmission lines.

Burner tip prices have many uses in electricity system planning studies, as well as inputs for various energy models. Electricity system planners may consider burner tip prices in their planning decisions. Determining what type of generation and other infrastructure to build will, in part, depend on projected fuel costs. The burner tip price represents that fuel cost for gas-fired generators. Burner tip prices will help electricity system planners determine the overall cost of gas-fired generation compared to alternatives.

Burner tip prices can be used as an input to models that forecast energy demand, supply, and prices. For example, the Energy Commission uses its Cost of Generation model, which estimates levelized costs on a dollar-per-megawatt-hour basis, for a variety of electricity generation technologies (both fossil and non-fossil).[2] A major input for gas-fired generators in the Cost of Generation model is the fuel cost or burner tip price, which, over the economic life of a gas-fired generator, is an important component of the operating cost. Production cost models also use burner tip prices in their electricity price forecasts. The Energy Commission uses the PLEXOS model for production cost modeling.[3]

1 See http://psc.wi.gov/thelibrary/glossary/gasTerms.htm.

2 See http://www.energy.ca.gov/2010publications/CEC-200-2010-002/index.html for more on the Cost of Generation model.

3 See the vendor product home page: http://energyexemplar.com/software/plexos-desktop-edition/ for additional detail or see http://www.ethree.com/downloads/CEC%20PIER/GHG_Tool_for_Buildings_in_CA_Jan09.pdf pages19-20 for more about implementations of the PLEXOS model.

This paper first examines and documents the Energy Commission's method of estimating burner tip prices; the method has not been documented. Examining the Energy Commission's method will provide opportunities to make improvements or changes for more accurate and realistic burner tip prices.

This report provides a starting point for updating and improving the Energy Commission's method over the next few years. The burner tip price estimation method should be examined regularly, every one to two years, to keep up with the changing natural gas industry and the needs of modelers who use burner tip prices for inputs. Factors affecting burner tip prices, such as supply, demand, transportation rates, natural gas procurement strategies, the amount of renewable energy coming onto the electric grid, and environmental policies, will change over the next 10–20 years.

This report also compares the Energy Commission's burner tip price estimation method to the methods of other entities. This comparison will provide insights to how others estimate burner tip prices, as well as provide opportunities to improve upon the Energy Commission method. Comparing the burner tip price estimates will show how different assumptions and estimation methods will affect results.

This paper can also support the Energy Commission method as it is used outside the Commission. Other agencies, such as the Western Electricity Coordinating Council (WECC), use burner tip price estimates for their electricity modeling effort. WECC staff has recently shown interest in the Energy Commission method.

There are a variety of ways to estimate burner tip prices. The two main differences between estimation methods are how the natural gas is purchased and how the cost of transportation is represented. Most of the burner tip price estimates examined are roughly in line with the Energy Commissions estimates, although differences exist.

Among the next steps is having this natural gas burner tip price paper vetted by other agencies/stakeholders to gain input and feedback. Also, a schedule for updating this analysis of burner tip prices should be set in place to assure this work continues and remains up to date.

Going forward, this work can be improved by making different assumptions about the transportation rates and how and where natural gas is procured. Determining how and where natural gas-fired generators procure natural gas will prove difficult as much of this data in confidential. Some of the other burner tip price estimation methods examined can provide different assumptions to incorporate into the Energy Commission's method. Analyzing natural gas burner tip prices should become a regular part of the *Integrated Energy Policy Report* (*IEPR*) process as modelers both within and outside the Energy Commission use burner tip price estimates and have shown interest in the Energy Commission's method. Natural gas is an important resource for electricity generation and will continue, as the role of natural gas has expanded to include backing up intermittent renewable energy. A current set of burner tip price estimates and assumptions will help electricity system planners make informed decisions on which resource mix will best serve load while meeting other criteria, such as environmental policies and the cost to generate electricity.

Organization of Report

Chapter 2 describes the Energy Commission's burner tip price estimation method. The treatment of the commodity price of natural gas (the gas itself) and the cost to transport natural gas (transportation rates) are examined. Annual natural gas prices from the Rice World Gas Trade Model (WGTM) are converted to monthly prices to capture some of the seasonal price variations.[4] The natural gas transportation rates used are the tariffs posted on the interstate pipeline or gas utility websites. Firm transportation rates are used rather than interruptible rates.

Chapter 3 looks at burner tip price estimates performed by other agencies, including the CPUC and WECC. This chapter discusses the methods and results of these other burner tip price estimates. Other burner tip price estimation methods and price results are compared to the Energy Commission method and price results. Two burner tip price backcasts are examined and compared to the Energy Commission estimates. A backcast is a forecast that uses historical data and outputs results over a historical period so the results can be compared to actual historical data to test the accuracy of the forecasting method.

The last chapter discusses the conclusions, lessoned learned, next steps, and potential future work. Although it is difficult to estimate burner tip prices, it is not impossible; in fact, historical prices match up reasonably well with the Energy Commission's price estimates. This chapter also examines alternative methods and assumptions for the Energy Commission to estimate burner tip prices. Some of these new methods may require information from pipeline companies, natural gas utilities, and natural gas-fired generator owners.

Appendix A, Method for Annual to Monthly Conversation Factors, discusses the methods used to convert natural gas prices from annual to monthly values.

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3 For more on the Rice World Gas Trade Model see http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27_workshop/presentations/01_Medlock_RWGTM_Reference_Case.pdf.

CHAPTER 2: Energy Commission's Burner Tip Price Estimation Method

Energy Commission staff has estimated burner tip prices since the early 1990s. The Energy Commission previously used the North American Regional Gas model.[5] The North American Regional Gas model forecasted wholesale natural gas prices as output; these prices required postprocessing adders to account for the transportation to move the natural gas to the burner tip. These burner tip price estimates were used by staff as inputs to production cost models to generate electricity prices. This is the first attempt to formally document the Energy Commission's burner tip price estimation method. The Energy Commission method should be documented and updated annually to fall in line with the *IEPR* and *IEPR Update* cycle.

The next section will examines the method, assumptions, and uncertainties associated with the Energy Commission burner tip price estimates. The following section is presented in two parts: commodity prices and transportation prices.

Commodity Component of Burner Tip Price

Depending on the type of estimate sought, the commodity price of natural gas may be based on an average monthly spot or monthly bid week price.[6] It could also be based on an annual average price produced from the WGTM. To reproduce historical burner tip prices or any type of backcast, spot or bid week prices are used from a published index.[7] For estimating future burner tip prices, WGTM forecasted output prices are used. The WGTM output prices need to be converted to monthly prices that capture the seasonal fluctuations in gas prices in the winter and summer. The next section discusses this annual-to-monthly conversion.

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5 The North American Regional Gas model was the predecessor to the WGTM that the Energy Commission currently uses.

6 A *spot price* is the price paid for natural gas in the spot market, it represents natural gas purchased for the same day or a day ahead. In the spot market trading can occur 24 hours a day, 7 days a week. *Bid week purchases* occur in the last week of every month and are for natural gas purchased for the following month. Bid week purchases are used to meet core natural gas needs. The largest volume of natural gas trading occurs during bid week.

7 Spot and bid week prices are readily available and account for a large portion of total natural gas procurement.

Table 1 lists the fuel groups modeled in the Energy Commission's representation of the western grid in its PLEXOS production cost model and the natural gas price hubs used for each fuel group. Burner tip price estimates are provided in regional groups called *fuel groups* developed for the PLEXOS model. A fuel group can represent a portion of a western state or part of a utility service area. A price hub for each fuel group was selected to reflect where each gas-fired generator purchases its natural gas. Staff went through the WGTM and *Natural Gas Intelligence* (*http://intelligencepress.com*) to determine the appropriate price point for each fuel group. The hub prices used for natural gas commodity price forecasting are from the WGTM model. Some of the WGTM hub prices differ from the *Natural Gas Intelligence* prices used for estimating historical burner tip prices. The Malin fuel group is not associated with a pipeline as the price hub is the same as the fuel group, and transportation up to Malin has already been accounted for.

Table 1: Price Hubs and Pipelines for Each PLEXOS Fuel Group

PLEXOS Fuel Group	NGI Price hub	Pipeline	WGTM Price Hub
Northern Arizona	Kern Delivery	Transwestern	AZ Flagstaff
Southern Arizona	El Paso S. Mainline	El Paso S.	AZ Phoenix
Colorado	CIG	Colorado Interstate Gas	Kit Carson
Idaho	Kingsgate	GTN	Alberta-Kingsgate
Kingsgate (ID)	North West Sumas	Transcanada-foothill system, GTN	Canada-British-Columbia-Sumas
Montana	CIG	Colorado Interstate Gas	Montana
Northern Nevada	Malin	Paiute	NV Reno
Southern Nevada	Kern Delivery	Kern River	NV Las Vegas
Northern New Mexico	Transwestern-San Juan	El Paso N., Transwestern	San Juan NM
Southern New Mexico	El Paso Permian	El Paso S.	Permian NM
Oregon	Stanfield	GTN	OR (Stanfield)
Malin	Malin		Malin
Utah	Opal	Questar	Utah
WA	Northwest Sumas	Cascade utility	US WA Seattle
Kingsgate (WA)	Kingsgate		Canada-Alberta-Kingsgate
Wyoming	Chetenne Hub	Colorado Interstate Gas	US Cheyenne
West Texas	WAHA	El Paso N.	TX West (Waha)
PG&E BB	PGE citygate	PGE BB trans	PGE
PG&E LT	PGE citygate	PGE distribution trans	PGE
SMUD < 85 MMcfd	PGE citygate	PGE BB trans	PGE
SMUD > 85 MMcfd	PGE citygate	PGE BB trans	PGE
Kern River	SoCal Border	SoCal transportation	Daggett
Mojave	SoCal Border	SoCal transportation	Daggett
Coolwater	PGE Citygate	PGE Transportation	Daggett
SoCal Gas	Socal citygate	Socal Distribution system	Socal gas
Blythe	SoCal Border	SoCal transportation	Ehrenberg
So. Calif Prod.	SoCal Border	SoCal transportation	San Joaquin Vally
TEOR	SoCal Border	SoCal transportation	San Joaquin Vally
SDG&E	SDG&E citygate	SDGE distribution system	SDGE
Otay Mesa	SDG&E citygate	SDGE distribution system	SDGE
Alberta	Nova/AECO	Transcanada-Alberta system	Alberta-AECO
British Columbia	North West Sumas	Transcanada-Alberta system	British Columbia Sumas
Rosarito	El Paso S. Mainline/ N. Baja	TGN	Mexico Baja

Source: *Natural Gas Intelligence,* the WGTM, and Electricity Analysis Office staff.

Converting Annual Prices to Monthly Prices

The Energy Commission uses the WGTM to provide price data in annual terms. Converting annual prices to monthly prices is a two-step process.[8] First, seasonality needs to be accounted for in creating monthly natural gas prices. In the winter months, natural gas tends to be more expensive (more heating load). A seasonal factor must be developed to account for the monthly price variations throughout the year. The seasonal factor is defined as the number that is multiplied by the annual price to get the monthly price for a given month. **Table 2** lists the seasonal factors that staff constructed. All the seasonal factors are similar; this similarity indicates that the seasonal variability in natural gas prices has not changed too much over the last 20 years. Regional weather patterns may change in the future, thereby affecting the seasonal factors going forward.

To obtain an annual-to-monthly seasonal conversion factor (seasonal factor), staff looked at 10 years of Henry Hub price data (2001–2011) and examined the relationship between monthly and annual prices. Staff also looked at 15 and 20 years of Henry Hub price data but chose to use the 10 years of data as the set fit historical prices better and was the most recent set of data staff examined. Staff averaged the computed seasonal factors for each year.

Table 2: Average Seasonal Factors for 10, 15, and 20 Years

	10 Year	15 Year	20 Year
Jan	1.04	1.10	1.10
Feb	0.97	0.99	0.98
Mar	0.95	0.94	0.94
Apr	0.98	0.97	0.97
May	1.01	1.00	1.00
Jun	1.02	1.01	1.01
Jul	1.04	1.02	1.01
Aug	0.95	0.95	0.94
Sep	0.94	0.94	0.94
Oct	0.98	0.98	0.98
Nov	1.05	1.06	1.06
Dec	1.06	1.05	1.07

Source: *Natural Gas Intelligence* and Electricity Analysis Office staff.

The second step in converting annual prices to monthly prices is accounting for the year-to-year changes in natural gas prices. For instance, the average annual Henry Hub prices in 2007 and 2008 were $6.86/million British thermal units (MMBtu) and $9.04/MMBtu, respectively. Using only the seasonal factor would not account for the $2.18/MMBtu increase from 2007 to 2008.

8 This process is discussed in more detail in Appendix A.

Staff used linear interpolation to account for the year-to-year changes in natural gas prices. Even if a natural gas price increases from one year to the next, it may not increase linearly each month. Natural gas prices may both increase and decrease throughout a given year.[9] Linear interpolation simplifies the analysis and fits historical data reasonably well.

Two methods for linear interpolation were analyzed: a typical January-through-December year and another using a June-through-May year. Staff decided to use the June-May year for its interpolation.[10] This method fits recent historical data well. The January-December year sometimes resulted in price jumps from December to January the following year. This generally happens when the average annual natural gas price for two consecutive years differs by a large enough amount.[11]

Once the appropriate interpolation method and seasonal factors are applied, the annual natural gas prices can be converted to monthly values. Looking at the Henry Hub price example just discussed, interpolating from 2007 to 2008, the first month price (June 2008) is computed by starting with the annual average 2007 price of $6.86/MMBtu and then adding the interpolation factor of $0.18/MMBtu ($2.18/12). Once the interpolation factor is added, this number is multiplied by the seasonal factor for June (1.02). This gives a price of $7.18/MMBtu. This same approach is used for each month in the forecast period.

Figure 2 plots 2007–2009 estimated monthly commodity natural gas prices using both the January-through-December and June-through-May years, as well as the seasonal factors. Actual monthly Henry Hub prices are graphed alongside the estimated values. This price graph highlights some key findings about both estimation methods. Both methods fail to capture the entire magnitude of the price spike in the summer of 2008, but the January-through-December year price estimates show a decline during that period. The June-through-May year estimates fit the actual data better than the January-through-December year estimates.

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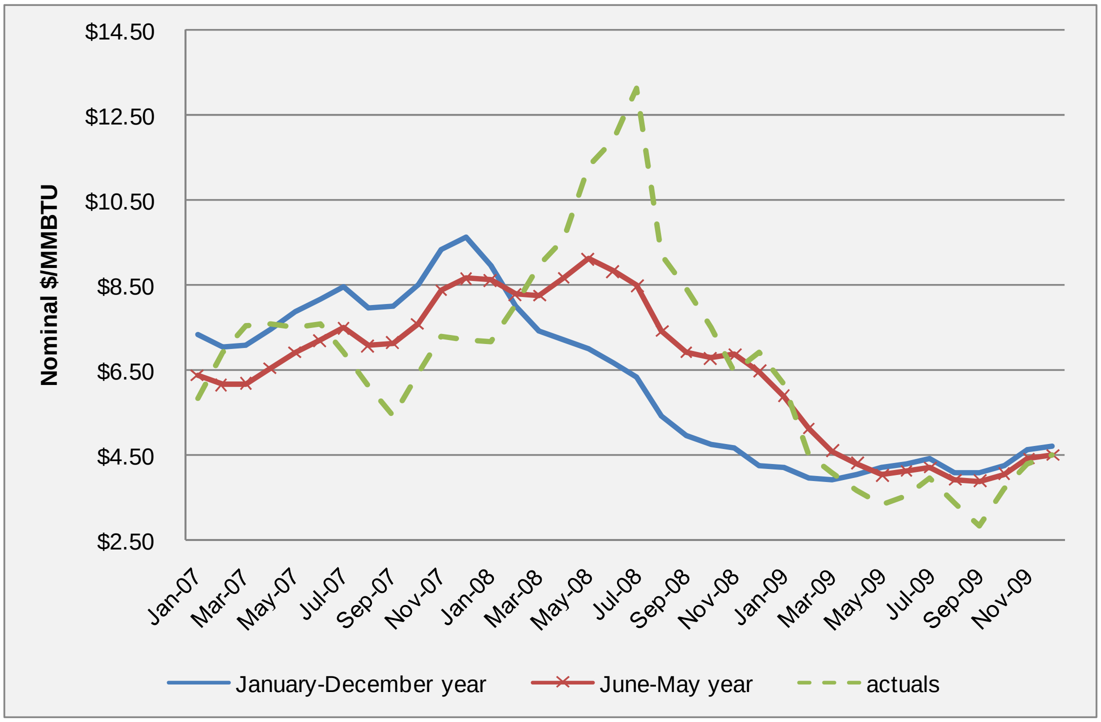
9 For example, Henry Hub prices decreased year-over-year from 2008–2009, although they increased for the first half of 2008.

10 For 2008 prices, the June-through-May year method assumes natural gas prices start in the month of June 2008 and go through May 2009.

11 See Appendix A for a more detailed description of converting annual prices to monthly prices.

Figure 2: 2007–2009 Monthly Estimated Henry Hub Prices vs. Actual



Source: *Natural Gas Intelligence* and Electricity Analysis Office staff analysis.

Caveats and Issues With Natural Gas Prices

Natural gas commodity prices come from forecast modeling, which contains many assumptions about the future state of the world, any of which could prove wrong. Little is known about the actual natural gas purchase strategies of natural gas-fired generators as most of this information is confidential. Natural gas-fired electric generators can purchase gas on the spot market through bid week contracts and multiple-year contracts. Bid week occurs in the last week of every month; bid week contracts are used by gas consumers to purchase gas for their core gas needs for the following month. The largest volume of natural gas trading happens during bid week. Natural gas-fired generators likely will procure a combination of short-term and long-term contracts, as well as bid week purchases.

A natural gas-fired generator can purchase gas from a border or citygate location (closer to the gas-fired generator) or from a natural gas basin, such as the Permian, San Juan, or Western Canadian Sedimentary basins (generally farther from the gas-fired generator). The Permian basin covers parts of Texas and New Mexico, and the San Juan basin covers parts of New Mexico, Colorado, Arizona, and Utah. The Western Canadian Sedimentary Basin is in western Canada. The decision on where to purchase natural gas from will differ for each gas-fired generator and will depend, in part, on the location of the gas-fired generator to natural gas pipelines and the demand profiles of its customers. The Energy Commission burner tip price estimation method assumes that a gas-fired generator will purchase gas from the price hub that is closest to it. This assumption is a simplification that adds consistency to the Energy Commission's estimation method.

Natural gas-fired generators will try to procure natural gas as cheaply as possible, while meeting any federal and or state requirements for serving load and maintaining reliability. The cheapest way to procure natural gas may be all basin purchases, all border or citygate purchases, or a combination or both.

Natural gas-fired generators will generally procure natural gas through a combination of border, citygate, and basin purchases. A gas-fired generator may change how it procures gas based on assumptions about future transportation rates and future basis differentials.[12] It is not possible to know the procurement strategy of each gas-fired generator. Staff was not able to find any reports/analysis on natural gas procurement strategies. The Energy Commission's model does not capture this differentiation in natural gas purchasing strategies.

The price data used for historical estimation come from *Natural Gas Intelligence* and were chosen based on locations relative to gas-fired power plants and natural gas pipelines. There may be pricing hubs more appropriate for a given power plant than what was available. Additionally, a power plant may purchase gas from multiple price hubs; staff estimations assume only one hub is used.

Many of the same issues affect estimating future burner tip prices. The Energy Commission estimation method uses natural gas price hubs that are in the WGTM; there may be other price hubs that better reflect where a power plant purchases gas. Assuming only one price hub is used to buy gas for each power plant fuel group may be incorrect. Some power plants may purchase/procure gas in a variety of ways: spot market purchases, monthly bid week contracts, long-term contracts, and New York Mercantile Exchange (NYMEX) futures contracts. Some long-term natural gas supply contracts can last for 10 years or more. The WGTM prices may not capture all of these gas procurement decisions that natural gas power plants face.

Finally, as the natural gas industry evolves, regional production profiles can shift.[13] These production shifts will likely change the relative price differences across different regional natural gas hubs. These relative price shifts can easily make a power plant decide to purchase natural gas from a different hub, or possibly pay a different price at one hub. In some instances, natural gas may become less available to the market, causing some power plants to shut down, pay higher prices, or find alternative sources of natural gas.

12 A *basis differential* is the cash spot price difference between to natural gas price hubs. It is usually defined as the price difference between the Henry Hub spot price and the spot price at another specified price hub.

13 The recent boom in shale gas production in New York and Pennsylvania are good examples of this.

Transportation Component of Burner Tip Prices

The second step in the Energy Commission's method for calculating burner tip prices is adding transportation rates to the commodity price of natural gas. Transportation rates are affected by compressor fuel costs, operating and maintenance costs of the pipeline, customer load profiles, the availability of pipeline capacity, as well as surcharges and other government fees.[14]

Transportation Rates Used for Estimating Burner Tip Prices

Staff used both interstate and intrastate transportation rates from each pipeline company or natural gas utility website; the most current rates were used. (Most rates are for 2010 or 2011.)[15] During the forecast period (2011–2030), staff assumes no real growth in transportation rates; in other words, transportation rates are held constant.[16] Staff assumes natural gas power plants procure all firm pipeline capacity. This is a simplifying assumption; sensitivities may be run in the future to allow growth and declines in pipeline transportation rates.

Staff also did not include a municipal surcharge that is included with many utility transportation rates.[17] Staff chose not to include municipal fees for simplicity and to balance out the higher firm transportation rates used. Also, it is not clear which generators pay the municipal fees and which do not.

Most natural gas pipelines offer both firm and interruptible service capacity, with firm transportation costing more than interruptible most of the time. Firm transportation contains both a reservation charge for the capacity on the pipeline and a demand charge for the natural gas transported. The capacity reservation charge for firm capacity service makes up the majority of the full transportation rate.

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14 *Compressor fuel costs* refer to the amount of natural gas used to run compressors that help transport gas through pipelines. This will be a cost to the entity shipping the gas.

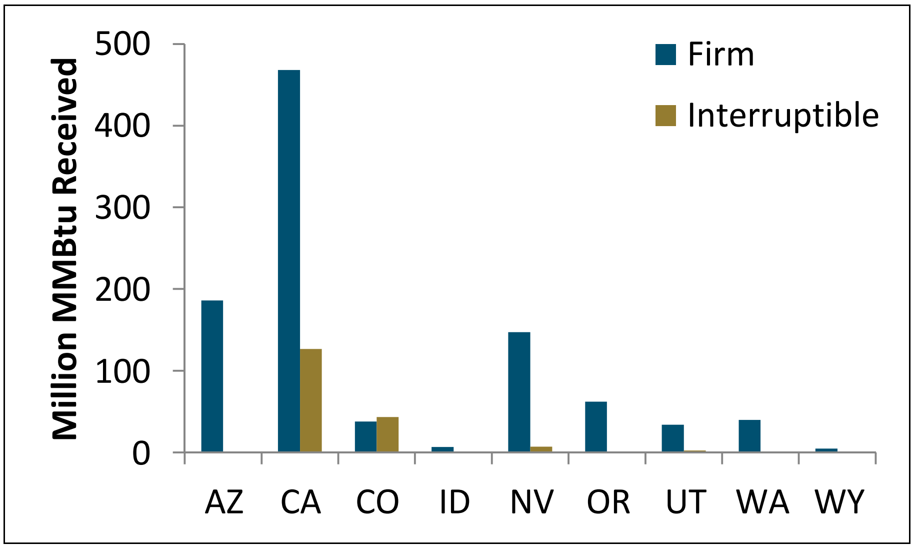
15 Interstate pipeline rates are used to account for the larger natural gas power plants that receive their gas directly off the interstate pipelines, while intrastate rates are used to account for power plants connected to the utility system. Both types of power plants exist in the western states.

16 Both Pacific Gas and Electric (PG&E) and Southern California Gas Company (SoCal Gas) have created pipeline safety enhancement plans that can potentially increase rates to end-use consumers of natural gas. See http://www.pgecurrents.com/2011/08/26/pge-files-milestone-plan-to-modernize-improve-safety-of-gas-pipeline-system/ and http://www.socalgas.com/safety/pipeline-safety-enhancement-plan/.

17 See http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G-SUR.pdf, and http://www.socalgas.com/regulatory/tariffs/tm2/pdf/G-MSUR.pdf.

Historical Energy Information Administration (EIA) data suggest that most gas-fired generators in the western states procure firm pipeline service (see **Figure 3**). Natural gas pipelines need firm commitments from customers to finance the building of the pipeline infrastructure. It is safe to assume that all pipelines will have some firm transportation customers. Pipeline companies also need firm commitments from customers to get their pipeline approved by FERC so the pipeline can be built. Firm transportation provides reliability that interruptible transportation does not. Reliability is becoming increasingly important with the interactions of the electricity and natural gas industries; it is reasonable to assume the importance of reliability will continue into the future. [18]

Figure 3: 2011 Firm and Interruptible Natural Gas Receipts Data



Source: United States Energy Information Administration Form 923 and E3 staff analysis (www.ethree.com).

Caveats and Issues With Transportation Rates

Natural gas pipeline transportation rates can both increase and decrease over time, although generally not uniformly or consistently. Shifting regional production profiles, relative natural gas commodity price differences, and discovery of new resources, such as the Marcellus shale formation in the eastern United States, can cause transportation rates to change. Pipeline maintenance and replacements, along with complying with environmental

18 Inside California, PG&E and SoCal Gas offer firm and interruptible (as-available) intrastate transportation under their tariffs. However, while transportation service may be labeled "firm," it is firm only if the gas company has sufficient capacity and does not have to curtail load. If curtailments are necessary, an electric generator under firm service would be curtailed on a pro rata basis, along with other noncore customers. This is because electric generators, as noncore customers, are by definition interruptible under CPUC D.86-12-010 and D.86-12-009, issued on December 3, 1986.

regulations, will likely cause rates to rise.[19] Technology advances in pipeline equipment and compressors that reduce the amount of natural gas lost in transport, as well as the pipeline depreciating over time, may send rates lower.

Some fuel groups in the PLEXOS model represent the receipt of natural gas from more than one pipeline; in these cases, the pipeline rates are added or volume weighted based on gas flows. Staff also assumed that each PLEXOS fuel group will receive natural gas from the same pipeline(s) for the whole estimation period. In actuality, natural gas power plants may receive gas from different pipelines over time as regional supply areas for natural gas shift or change.

For this analysis, staff assumed there is no real growth in transportation rates during the estimation period (2011–2030). Staff discussed using an annual growth rate for transportation rates. Transportation rates normally do not increase/decrease by the same amount each month and year. Staff ultimately decided against adding an annual growth rate/decline rate but will consider doing so for future work. Trying to forecast when pipelines/utilities will change their rates remains difficult. Both the PG&E and SoCal Gas transportation rates exhibit some volatility over the last 11 years. This change in rates is neither uniform nor consistent. Large interstate natural gas pipelines will have similar trends, and rate changes will not occur as frequently, while rates for intrastate pipelines (and gas utility distribution pipelines) will exhibit more volatility as they change more frequently.

Figure 4 shows historical interstate natural gas pipeline transportation rates dating back to the 1990s.[20] These transportation rates remain flat and/or decrease over time for the most part. However, there are a few cases where these rates increase. Natural gas utility rates exhibit more short-term variations than do the larger interstate natural gas pipeline rates. One reason for this is that natural gas utility rates are regulated by the CPUC and can change multiple times in a single year. Interstate transportation rates are regulated by the FERC and generally change much less frequently. Based on historical rate information, staff decided to hold interstate transportation rates constant for the entire estimation period.

Figure 5 shows historical transportation rates for gas utilities serving California customers from 1998 through February 2013. Both PG&E and SoCal Gas rates show a small amount of volatility, remaining mostly flat over the time horizon, with slight increases since 2011. Utility transportation rates in California have remained roughly the same over the last 10

19 See http://www.ingaa.org/File.aspx?id=10757 and http://www.pge.com/myhome/customerservice/energystatus/streetconstruction/gaspipereplacement/index.shtml.

20 These rates represent natural gas procured from each basin near the origin of each pipeline to the nearest delivery point to California. Each pipeline will have multiple rates depending on the delivery point.

years. Transportation rates for California utilities are expected to increase, however, because each utility is implementing a pipeline safety enhancement plan. As the exact rate impacts from the pipeline safety enhancement plan are unknown, staff decided to hold utility transportation rates constant for now.[21]

Both firm and interruptible pipeline service capacity can be negotiated. Negotiated transportation rates are considered nonconforming service agreements or alternatives to traditional cost-of-service ratemaking and must be approved through FERC.[22] Natural gas pipelines negotiate rates with its customers to keep rates competitive with other pipelines as well as offer more flexibility to its customers. A negotiated rate may differ from a cost-of-service rate (recourse rate) in the length of the contract, the amount of gas shipped, price paid for transportation, and the locations where the natural gas can be shipped. Negotiated rates, many times, are lower than traditional cost of service rates, but they can be higher, such as with short-term firm transportation.

Some natural gas pipelines discount their transportation rates to retain existing customers or gain new ones. Both firm and interruptible pipeline rates can be discounted. Discounted rates must be competitive and not harm any currently effective customers; these rates also need to be approved by FERC.[23] Discounted rates are not negotiated between the pipeline and its customer; these rates are determined by the pipeline and then approved by FERC. A discounted rate must be offered to all pipeline customers.

Interruptible pipeline capacity is considered a discounted rate, along with pipeline capacity purchased in the capacity release market.[24] Many natural gas pipeline customers (natural gas power plants) will purchase firm and interruptible pipeline capacity. Furthermore, gas-fired generators can have both cost of service-based rates and negotiated or discounted rates.

Interruptible pipeline services are generally priced in a range that encompasses the firm rate; thus, firm transportation rates represent the higher end of what power plants

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21 The pipeline safety enhancement plans will upgrade natural gas pipelines and infrastructure. See http://www.pgecurrents.com/2011/08/26/pge-files-milestone-plan-to-modernize-improve-safety-of-gas-pipeline-system/ and http://www.socalgas.com/safety/pipeline-safety-enhancement-plan/.

22 For more on negotiated and discounted transportation rates, see http://www.gpo.gov/fdsys/pkg/FR-1996-02-07/pdf/96-2547.pdf.

23 A common discount level for discounted rates is 10–20 percent less than the firm cost of service rate.

24 Firm gas shippers may sell their unneeded pipeline capacity to bidders who need to acquire capacity. The bidders bid on the released capacity with the highest value bidder winning.

potentially pay for transportation.[25] Interruptible pipeline service has no reservation charge, but customers of this service may be bumped off the pipeline to meet firm customers' needs.

Firm pipeline capacity generally costs much more than interruptible pipeline capacity; however, firm pipeline capacity customers don't get bumped off the pipeline for another customer. A customer purchasing firm pipeline capacity must pay a reservation charge to reserve the pipeline capacity and not get bumped off. The reservation charge makes up the majority of the full firm pipeline rate.

Many natural gas power plants procure firm pipeline capacity on a long-term period (10 years or more). Procuring pipeline capacity many years at a time provides the pipeline customer revenue certainty (as the price is locked in) and ensures that pipeline capacity will be available to that customer in the future. Some pipelines offer short-term firm transportation contracts (20 days) for those customers who do not need firm capacity the whole year.

Choosing only one type of transportation rate for many power plants may be incorrect when a variety of rates exist. Baseload natural gas power plants are more likely to hold firm capacity, while peaker power plants, with much lower capacity factors, are more likely to hold interruptible pipeline service. In some regions of the United States, electric generators buy interruptible capacity because firm capacity is not available.[26] Power plants are able to hold both firm and interruptible pipeline capacity, as well as pipeline capacity that has been negotiated or discounted. Power plants likely will procure a combination of different types of pipeline capacity that best suits their operational needs and constraints.

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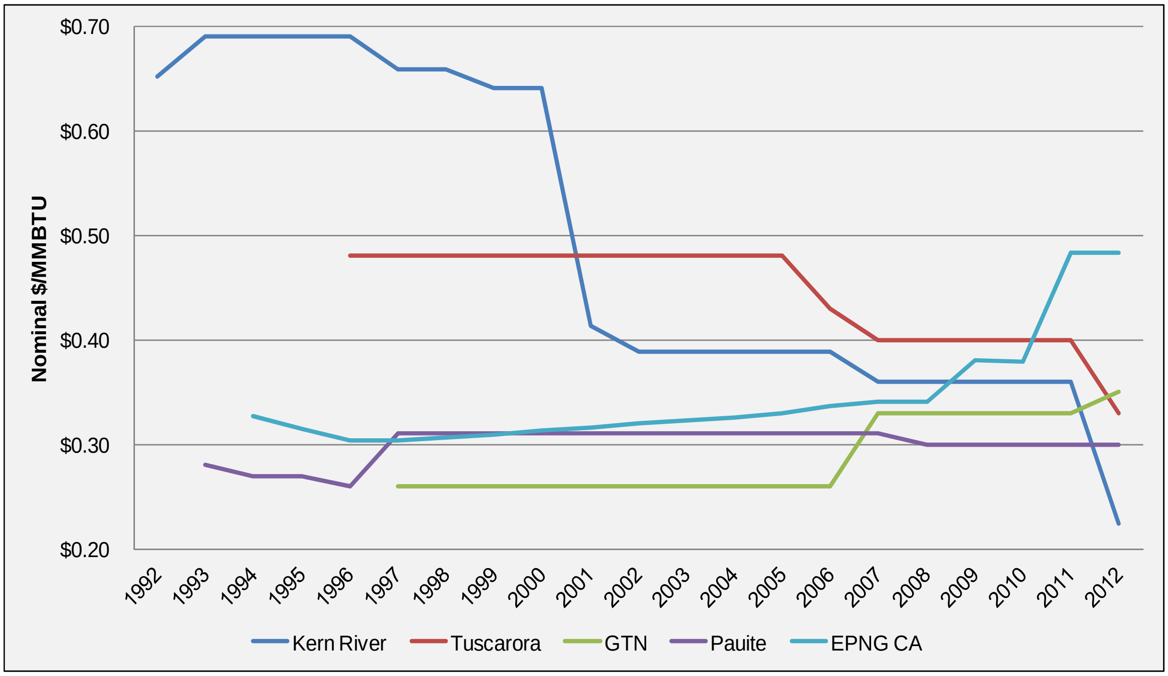
25 Some natural gas pipelines have an interruptible that is higher than their firm rate. See http://www.transcanada.com/customerexpress/854.html and http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G-AA.pdf.

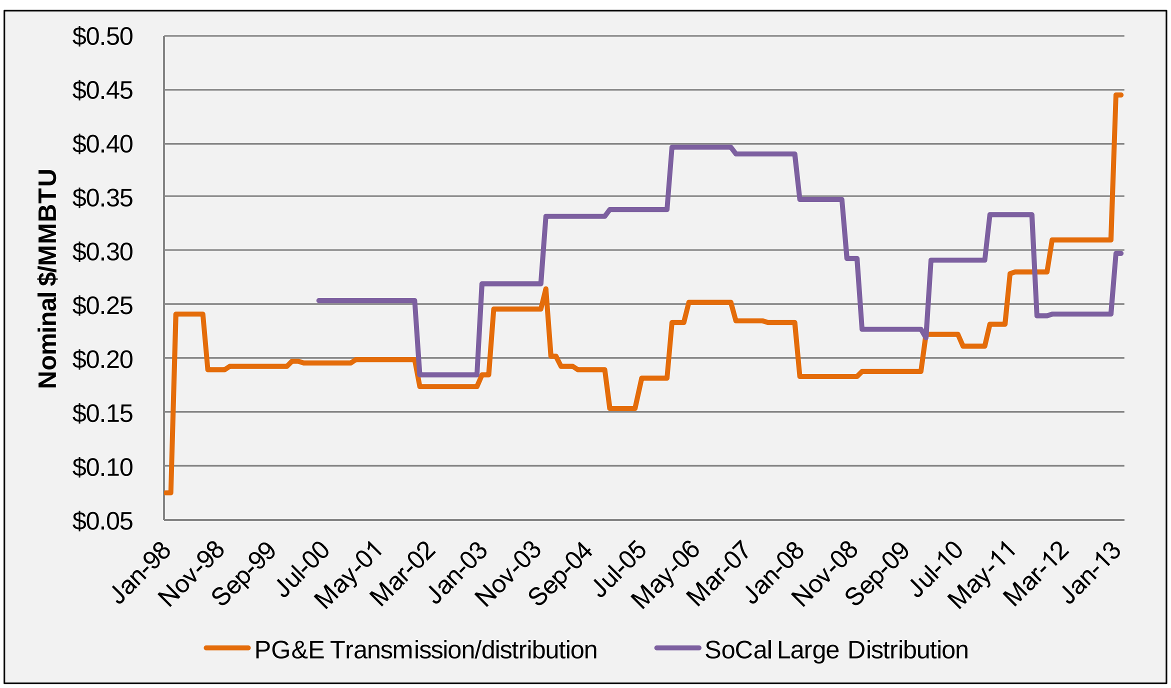
26 See www.naesb.org/pdf/geic020105w5.doc.

Figure 4: Interstate Historical Natural Gas Transportation Rates



Source: Kern River Gas Transmission, Tuscarora Pipeline, Gas Transmission Northwest, and Paiute Pipeline, El Paso Pipeline.

Figure 5: PG&E and SoCal Gas Natural Gas Transportation Rates for Electric Generation, 2000–2011



Source: http://www.pge.com/nots/rates/tariffs/rateinfo.shtml and SoCal Gas.

CHAPTER 3: Examination of Other Burner Tip Price Estimates

This section analyzes the burner tip price estimates and methodologies of other entities and compares them to the estimates and method used by the Energy Commission. Some burner tip price estimates and methods are not documented completely; thus, it is difficult to directly compare these estimates and methods to those of the Energy Commission. In general, the Energy Commission method has similar assumptions to other burner tip estimation methodologies, and the estimated burner tip prices are fairly similar. Some methods use public data, while others use confidential or proprietary data. **Figure 6** compares California burner tip price estimates of the Energy Commission with those of the Northwest Power and Conservation Council (NWPCC) and the CPUC's Market Price Referent (MPR). The price estimates are similar, although in the near term (2012-2014) the estimates tend to diverge. The Energy Commission burner tip price estimates grow slower out through 2030 than do the other estimates.

Other entities besides the Energy Commission estimate natural gas burner tip prices. The CPUC, NWPCC, WECC, and the California utilities' *California Gas Report* have all estimated natural gas burner tip prices. Each method will depend on the purpose and expected use of the burner tip price estimate. Not all the assumptions on the natural gas commodity price in the different forecasts were available; however, where the assumptions were available, they were generally similar to those of the Energy Commission.

Natural gas commodity price forecasts can be constructed using both a general equilibrium model and NYMEX futures contract prices. Some natural gas commodity price forecasts combine these two methods. A general equilibrium model analyzes the interactions of supply and demand in the market through mathematical equations, and outputs a price when supply and demand are equal. This type of model will sometime needs to perform many iterations of supply and demand interacting before a price is determined.

The burner tip price methodologies of the CPUC, NWPCC, and WECC have similar assumptions about intrastate transportation rates; however, all assume a small annual growth rate for transportation rates. For interstate transportation rates, most other burner tip price estimates use data on financial basis swaps or historical regional natural gas price differentials to account for the cost of transportation.[27]

The MPR developed by the CPUC represents the long-term ownership, operating, and fuel costs of a new 500 megawatt combined-cycle gas turbine. The fuel costs used for the MPR are natural gas burner tip price estimates. The MPR uses a combination of NYMEX Henry

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27 A *basis swap* is a transaction where one party receives a fixed price for the price difference between the Henry Hub price and another specified price location, and the other party receives the actual floating price (the true price differential). Basis swaps are used mainly to hedge against regional price movements.

Hub futures contracts and fundamental price forecasts for the commodity portion of its estimates. The MPR uses basis swap data to represent the price of interstate transportation and utility transportation tariffs for intrastate transportation rates inside California.

The NWPCC estimates burner tip prices for its *Sixth Northwest Power Plan*[28] using an econometric spreadsheet model that starts with average United States wellhead prices and converts them to Henry Hub and then regional prices, using historical basis differentials and an econometric model. Firm intrastate and interstate transportation rates are added to regional prices to obtain a burner tip price.

The WECC estimates monthly burner tip prices for 2010; this is a backcast that can be compared to historical burner tip prices. Burner tip prices are estimated for each balancing authority in the western states by the WECC using a spreadsheet model. This backcasting exercise is performed to validate and improve production cost modeling in the Transmission Expansion Planning Policy Committee (TEPPC) dataset. This backcast will help calibrate and improve production cost modeling to produce more realistic simulations in 10-year datasets.

The WECC method uses historical burner tip prices from the EIA. Financial data on commodity prices from the Intercontinental Exchange (ICE) and firm transportation rates from pipeline and gas utility websites are used to account for transportation costs when the EIA data are not sufficient.

The *California Gas Report* has estimated natural gas burner tip prices as part of its modeling. These price estimates are then used for modeling electricity generation dispatch. The *California Gas Report* burner tip prices represent usage for cogeneration and other industrial applications, as well as electric generation inside an oil refinery. The *California Gas Report* uses both NYMEX Henry Hub futures prices as well as fundamental forecasts for the commodity price forecast. Transportation costs are represented by both financial basis swaps and intrastate transportation rates.

Ventyx Velocity Suite (Ventyx) provides historical burner tip prices that it collects from EIA Form 923 data. Staff aggregates the Ventyx power plant level data into subregions of the WECC, such as Northern and Southern California, and Northern and Southern Nevada. These historical prices are examined and compared to staff's burner tip price estimates. An additional estimation method is included that uses historical bid week natural gas prices coupled with the transportation rates used in staff's burner tip price estimates; this additional method is compared to the Ventyx historical prices and staff's estimated burner tip prices. All of these burner tip price estimates and methods are discussed in more detail later in this section.

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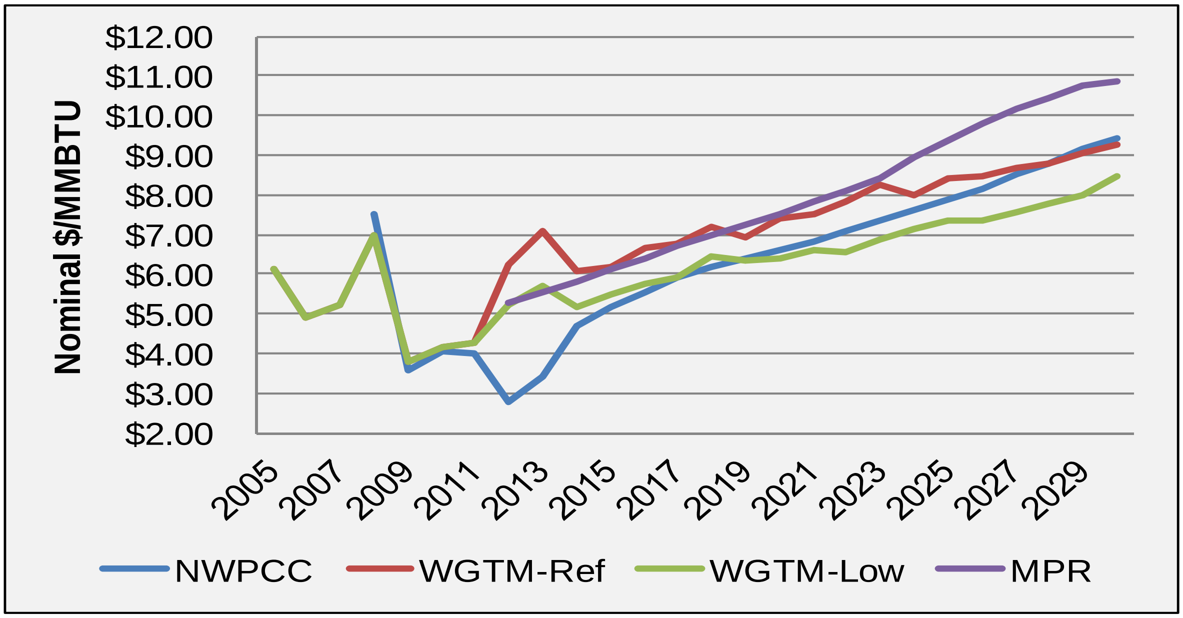
28 The *Sixth Northwest Power Plan* is a five-year plan adopted by the NWPCC that guides the Bonneville Power Administration and details a strategy to meet future demand for electricity in a manner that assures an adequate, economic, affordable, and reliable power supply. The plan looks 20 years into the future. See http://www.nwcouncil.org/energy/powerplan/6/summary/.

Figure 6: California Burner Tip Price Estimates



Source: Northwest Power and Conservation Council, 2011 CPUC Market Price Referent, and Electricity Analysis Office staff analysis.

California Public Utilities Commission Market Price Referent

The MPR developed by the CPUC represents the long-term ownership, operating, and fuel costs of a new 500 MW combined-cycle gas turbine. The fuel costs used for the MPR are natural gas burner tip price estimates. The MPR has been used to calculate the cost of compliance with greenhouse gas regulation, establish the price for the renewable energy feed-in-tariff program, as well as representing a reasonableness benchmark price for Renewables Portfolio Standard contracts.[29]

The burner tip price estimates for the MPRs use a 22-day trading average of Henry Hub NYMEX futures contracts for the first 12 years of the forecast period. For the remaining years, an average of three fundamental forecasts is used.[30] The MPR uses financial basis swaps to convert Henry Hub prices to California commodity prices for PG&E and SoCal

29 For more on the CPUC's MPR, see http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr. The year 2011 was the last year the CPUC used the MPR method. The CPUC now uses the Renewable Auction Mechanism and feed-in-tariffs to establish a reasonableness benchmark price for renewable energy contracts to meet California's Renewables Portfolio Standard goals.

30 The MPR uses an average of three out of four private sector natural gas Henry Hub price forecasts; the four forecasts are Cambridge Energy Research Associates, PIRA Energy Group Global Insight, and Wood Mackenzie. See http://docs.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/154753.PDF.

Gas. These two utility prices are averaged to get a California commodity price. The basis swaps represent the cost of interstate transportation to get natural gas to California.

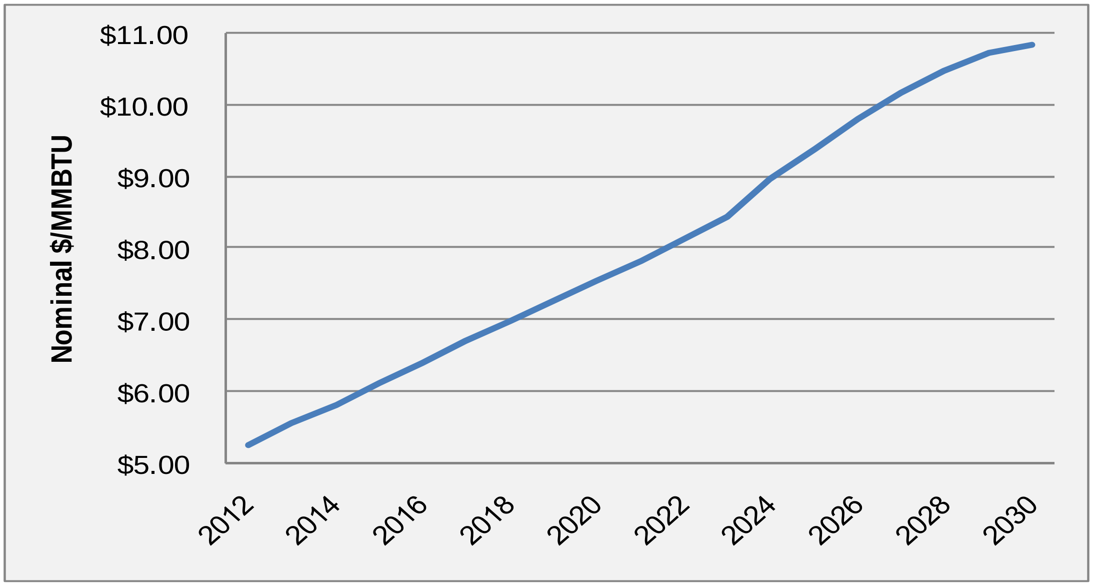
The transportation rate used to deliver California natural gas to the burner tip for electricity generation is an average of the SoCal Gas and PG&E distribution rates for electric generators. This average transportation rate is added to the California commodity price to get the burner tip price. The backbone level and transmission level transportation rates are both less expensive than the distribution rate.[31] A municipal surcharge and a gas franchise fee surcharge are also added to the transportation rate.[32] This average transportation rate is assumed to increase 1.81 percent each year, based on the escalation rate in the EIA's gross domestic product forecast. This forecast is discussed in more detail in the MPR model on the CPUC website.

Figure 7 shows the burner tip price estimates of the MPR in nominal $/MMBtu from 2012 through 2030. The prices increase uniformly through the forecast period and appear to increase more linearly over the first 12 years. This linear trend is explained mainly by the use of NYMEX futures contracts; after the first few months, futures contracts generally increase in a linear fashion. There is a small jump in prices in 2024 (the last year of NYMEX data), and prices rise more steeply for the remainder of the estimation period. The last section of the burner tip price estimates (2025 and onward) is derived by fundamental forecasting models for the natural gas commodity price forecast; thus, it is expected to look different from the NYMEX portion.

31 Backbone level transportation transports gas to large gas-fired generators (usage greater than 50 million therms per year) rather than small generators that are served by the transmission and distribution pipelines. The backbone level transportation rates are less expensive as they require less metering and administrative costs.

32 See http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G-SUR.pdf and http://www.socalgas.com/regulatory/tariffs/tm2/pdf/G-MSUR.pdf.

Figure 7: MPR California Burner Tip Price Estimates



Source: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.

California Public Utilities Commission Market Price Referent vs. Energy Commission

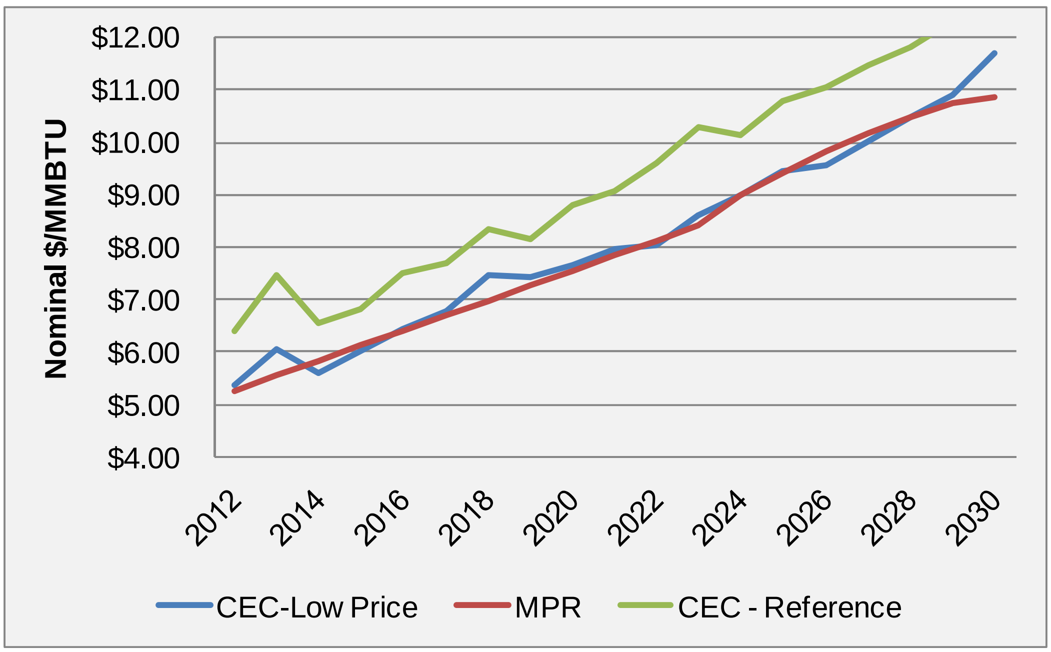
The MPR estimates burner tip prices using NYMEX Henry Hub futures contracts prices for the first 12 years. Instead of using interstate transportation rates, the MPR uses financial basis swaps (from ICE) for the SoCal Gas border and PG&E citygate locations. After the first 12 years, a fundamental Henry Hub price forecast is used. The MPR and Energy Commission burner tip price estimates will be compared in annual terms, as those are the price units within which the MPR estimates are located.

The MPR forecast assumes transportation rates escalate at 1.81 percent each year, while the Energy Commission forecast assumes no real growth in transportation rates. The MPR forecast is in nominal dollars, as is the Energy Commission forecast. Nominal dollars are dollars that are not adjusted for inflation. Also referred to as current dollars, nominal dollars represent the actual amount of money spent or earned over a given period. The Energy Commission burner tip price estimates do not include the municipal surcharge fees that the MPR does. Both estimates assume firm utility transportation rates for inside California. Lastly, the MPR provides a "California" burner tip price, which is the average of PG&E and SoCal Gas burner tip prices; the Energy Commission estimates will take the average of PG&E and SoCal Gas prices as well for the comparison.

Figure 8 plots the MPR burner tip price estimates along with the Energy Commission's estimates; staff uses the reference and low price case commodity price forecasts for this comparison. The Energy Commission low price case commodity price forecast is more comparable to the low natural gas prices currently in the market; the reference case is included to expand the comparison. The Energy Commission and MPR estimates have almost identical slopes over the forecast period, and the Energy Commission estimates using its low price case commodity price forecast fit well with the MPR forecast. As the MPR forecast is based on mainly financial prices, the close fit of the forecasts shows that the physical and financial natural gas markets are linked.

The main difference between the two burner tip price estimates is volatility: the Energy Commission estimates exhibit some volatility, while the MPR estimates are more smoothed. After the first 12 years of NYMEX futures price data, the MPR estimates display a growth rate (slope) that starts to decrease. The slope of the Energy Commission estimates remains mostly unchanged over the time horizon. Although this is the only annual comparison, the MPR appears to have a very good fit with the Energy Commission estimates.

Figure 8: 2011 MPR vs. Energy Commission Burner Tip Price Estimate for California



Source: CPUC and Electricity Analysis Office staff analysis.

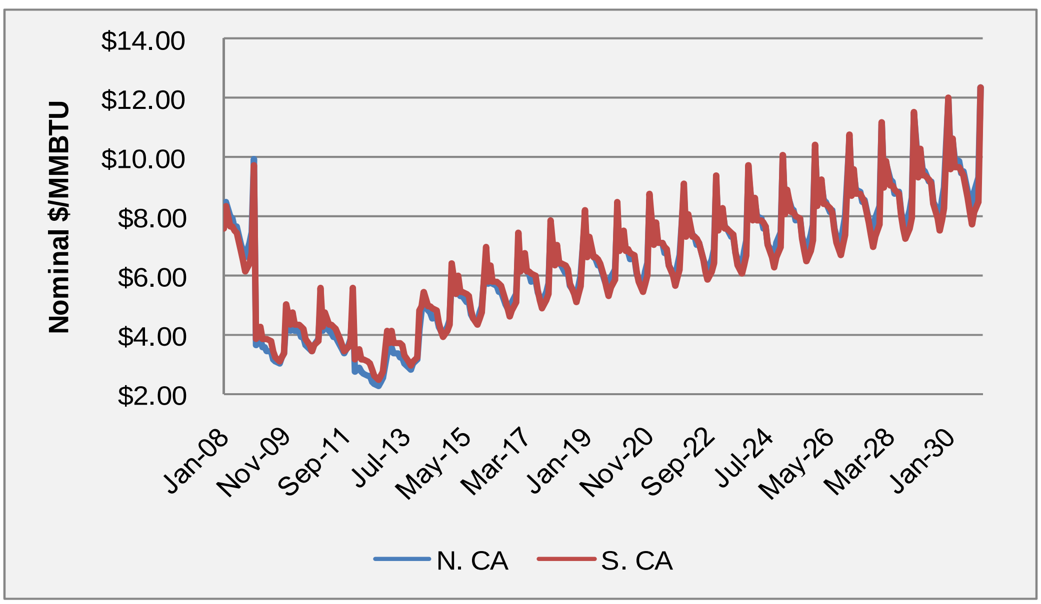
Northwest Power and Conservation Council Burner Tip Price Forecast

The NWPCC burner tip price estimates are developed using an econometric spreadsheet model that starts with average United States wellhead prices. These annual prices are converted to monthly prices using historical trends in monthly price movements. The monthly average U.S. wellhead prices are then converted to Henry Hub prices using historical relationships between the two prices. The Henry Hub prices are converted to regional hub prices using historical basis differentials in econometric equations.[33]

To convert regional natural gas hub prices into burner tip prices, the NWPCC added pipeline transportation rates for each price hub. Pipeline fuel costs and pipeline reservation charges for firm capacity were also added.[34] The prices examined here are from the NWPCC medium case. Some of the key assumptions from the medium case include shale gas production will continue to put downward pressure on prices, power plant conversions from coal to gas will continue, and the United States will have an economic recovery. Other burner tip price estimates have more detailed assumptions.

Figure 9 shows NWPCC burner tip price estimates for Northern and Southern California. The NWPCC provides burner tip price estimates for both existing and new power plants; the new power plants are assumed to have slightly higher fixed operating costs. For simplicity, an average of these two prices is used. The NWPCC price estimates show a small growth rate over the forecast period, which appears mostly linear. These burner tip price estimates show a seasonal pattern with increasing volatility over the forecast period. This pattern is the result of the historical relationship between annual and monthly average U.S. wellhead prices and the econometric spreadsheet model, as discussed earlier, as well as high heating demand in the winter.

Figure 9: NWPCC Medium Case Burner Tip Price Estimates



Source: http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Appendix_A.pdf.

33 The regional natural gas price hubs in this forecast include Alberta Energy Company, Sumas, the Rockies, and the San Juan and Permian Basins.

34 For more on the NWPCC natural gas price forecast, see http://www.nwcouncil.org/media/6293/SixthPowerPlan_Appendix_A.pdf.

Northwest Power Conservation Council Medium Case vs. Energy Commission Low and Reference Cases

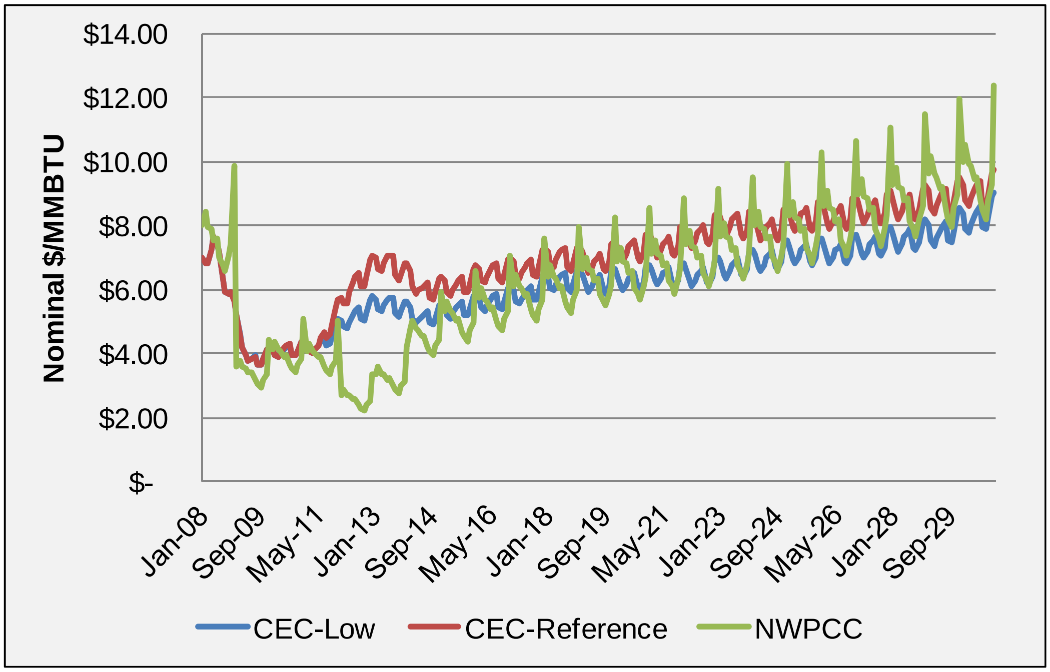
The price estimates examined in this comparison with the Energy Commission burner tip price estimates are from the NWPCC medium case. The NWPCC medium case assumptions line up best with the Energy Commission low price case assumptions, so these two cases will be compared. The Energy Commission reference case burner tip price estimates are also added as a second comparison with the NWPCC estimates. The NWPCC estimates burner tip prices for Northern and Southern California; therefore, the Energy Commission will use estimates for the PG&E and SoCal Gas service areas as these are the closest representations of Northern and Southern California. These comparisons are not exact because Northern and Southern California both contain gas-fired generators that are not in a utility service area; merchant gas-fired generators are an example.

Figure 10 and **Figure 11** both illustrate this comparison. The burner tip price estimates for both Northern and Southern California match up fairly well with both the Energy Commission reference case and low price case estimates, although the reference case price estimates fit slightly better than the low price case estimates. Both estimates show similar growth rates, although the NWPCC estimates have slightly higher growth rates.

Both of the NWPCC burner tip price estimates show more seasonal volatility than the Energy Commission estimates; furthermore, the seasonal volatility of the NWPCC estimates appear to increase over time while the seasonal volatility of the Energy Commission estimates remains constant. One potential reason for seasonal volatility differences is that the NWPCC uses historical average U.S. wellhead prices for its seasonal variation, while the Energy Commission uses historical Henry Hub prices. The other main difference between the NWPCC and Energy Commission estimates is the price level from 2012 through 2014. The NWPCC estimates show a price dip that goes down to the high $2/MMBtu level, while the Energy Commission estimates show a price bump over the same period that goes up to the high $5/MMBtu level. Historical commodity prices for the PG&E and SoCal Gas citygate price hubs both average close to $3/MMBtu in the 2011–2012 period.[35] Looking at these historical data, actual burner tip prices in 2012 fall in between the Energy Commission and NWPCC estimates, although the NWPCC estimates appear to be a little closer to the historical data. Lastly, the NWPCC estimates better capture the magnitude of the summer 2008 natural gas price spike.

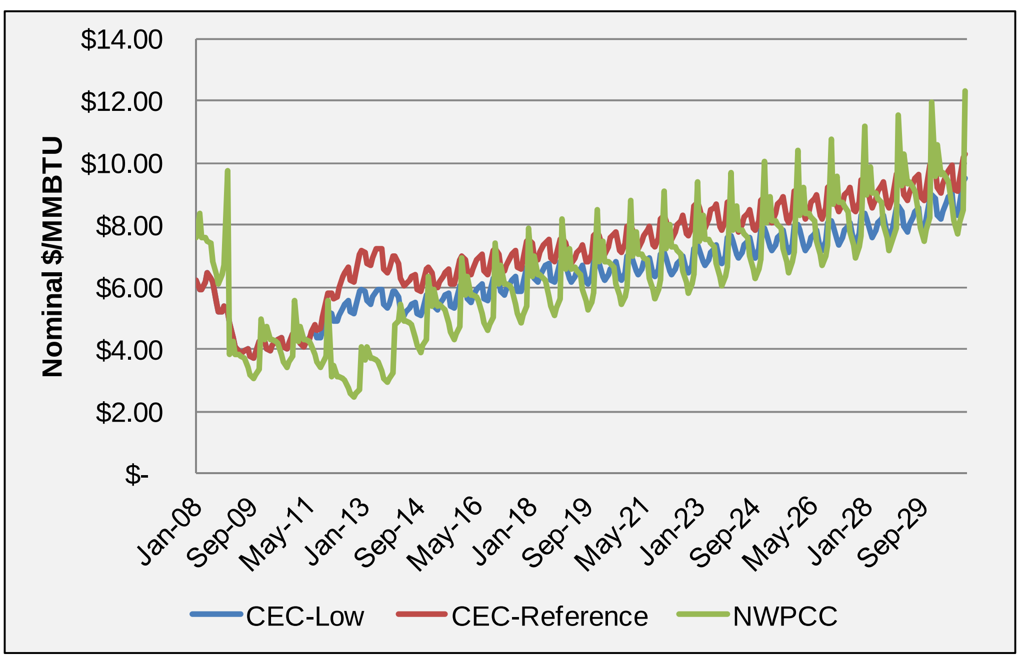
35 These historical prices are averaged from January 1 2012, through November 14, 2012.

Figure 10: Northern California Burner Tip Price Estimates, NWPCC vs. Energy Commission



Source: NWPCC and Electricity Analysis Office staff analysis.

Figure 11: Southern California Burner Tip Price Estimates, NWPCC vs. Energy Commission



Source: NWPCC and Electricity Analysis Office staff analysis.

Western Electricity Coordinating Council 2010 Backcast

The WECC monthly burner tip prices are estimated for each balancing authority in the western states using historical natural gas commodity prices from the ICE as well as price data from EIA Form 923.[36] [37] This backcasting exercise is performed to validate and improve production cost modeling in the TEPPC dataset.[38] The backcast helps calibrate and improve production cost modeling to produce more realistic simulations in 10-year data sets. These monthly burner tip price estimates are for 2010.[39] Financial data on natural gas commodity prices from the ICE are used when the EIA data were insufficient. When ICE data are used, a transportation rate is added to the commodity price to get a burner tip price. The transportation rates for interstate and intrastate natural gas pipelines are in line with the Energy Commission's transportation rates.

Figure 12 shows estimated burner tip prices for two balancing authorities: the Balancing Authority of Northern California for the northern portions of the state and the Los Angeles Department of Water and Power for the southern portions. Burner tip prices in Northern California are slightly less expensive than prices in Southern California; however, it is difficult to draw conclusions from one year of data with prices that are so similar.

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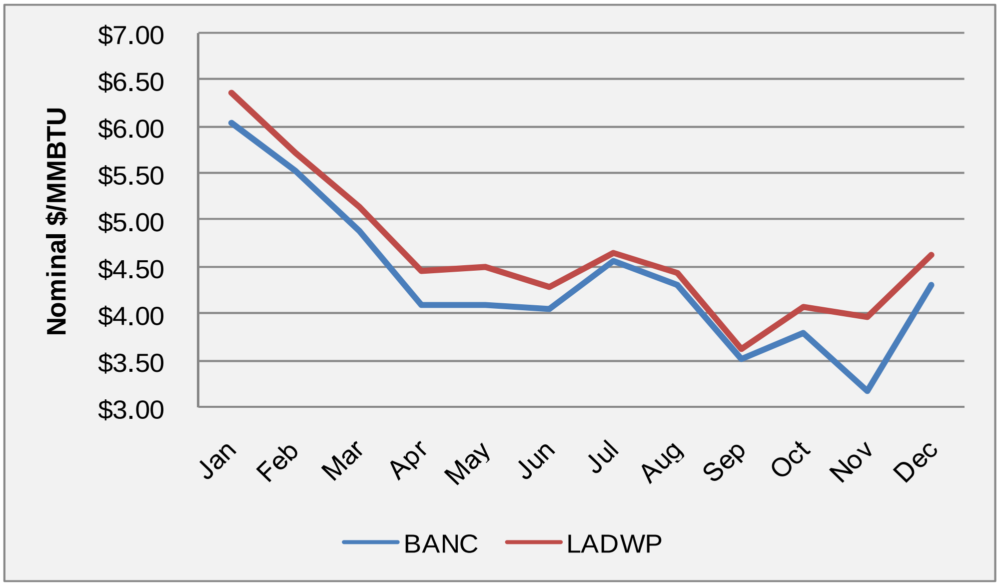
36 See http://www.eia.gov/electricity/data/eia923/.

37 A *balancing authority* is an entity that integrates resource plans ahead of time and supports interconnection frequency in real time as well as maintains load-interchange-generation balance within a region. For a list of balancing authorities in the WECC, see http://www.wecc.biz/library/WECC%20Documents/Publications/WECC_BA_Map.pdf.

38 For more on TEPPC, see http://www.wecc.biz/committees/BOD/TEPPC/default.aspx.

39 Data for this backcast were obtained through EIA-923 forms, which survey power plants for burner tip prices. For more on EIA Form 923, see http://www.eia.gov/electricity/data/eia923/.

Figure 12: WECC 2010 Backcast Burner Tip Prices



Source: EIA Form 923 data reports and www.theice.com natural gas month-ahead and once-through-cooling reports.

Western Electricity Coordinating Council 2010 Backcast vs. Energy Commission Burner Tip Price Method

The WECC backcast will be compared to the Energy Commission burner tip price estimates using historical bid week natural gas commodity prices from *Natural Gas Intelligence*. Bid week commodity price data are used as this comparison spans only one year. The annual commodity price output from the WGTM is more of a long-term forecast and may not provide the best burner tip price estimates for a one-year comparison. The WECC burner tip price estimates are broken down by balancing authority; this is not the same breakdown as the Energy Commission estimation method. Staff matched the appropriate balancing authorities to each PLEXOS fuel group. (This mapping is not an exact match.) The comparison will examine burner tip prices in the PG&E, SoCal Gas, Northern Nevada, and Southern Nevada regions.

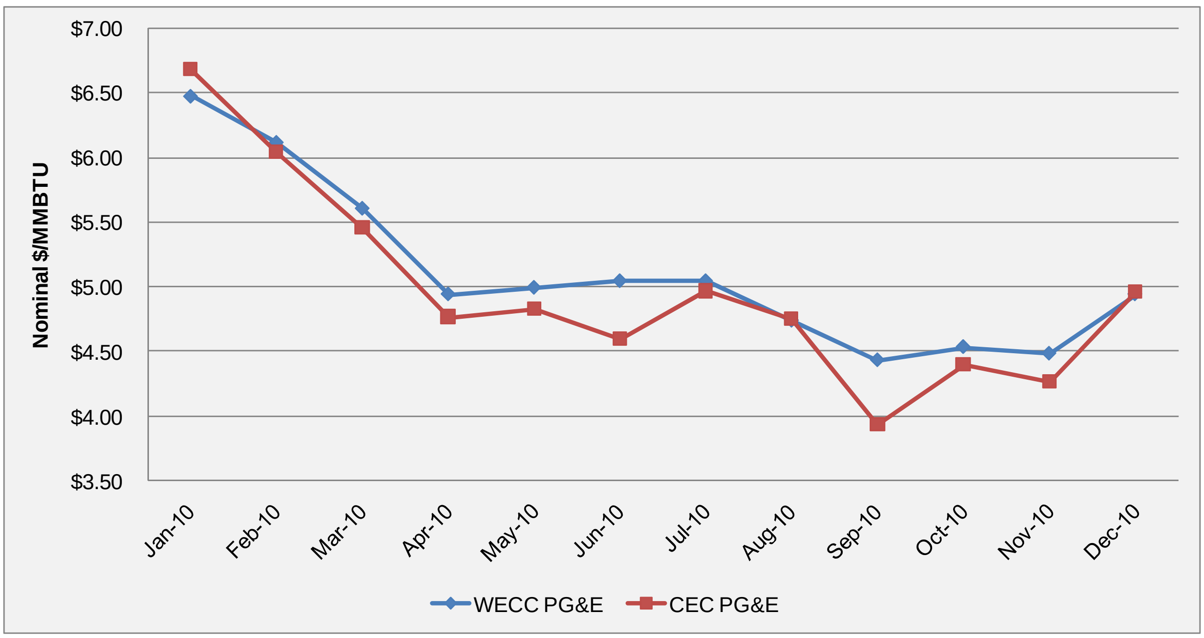
The comparisons show the Energy Commission's estimates are generally a little lower than WECC's estimates. Several factors contribute to the Energy Commission prices being different, and lower, than the WECC price estimates. First, the WECC uses both EIA Form 923 and month-ahead natural gas prices from the ICE, while the Energy Commission estimates use monthly bid week prices from *Natural Gas Intelligence*. The ICE month-ahead prices are financial prices and, thus, may contain a risk premium, whereas the *Natural Gas*

Intelligence prices are physical index prices determined by supply and demand interactions in the market.[40]

The WECC estimates use the same intrastate transportation rate as the Energy Commission estimation method. Also, the mapping from balancing authorities to each PLEXOS fuel group is not perfect; some overlap may occur. All of these factors can contribute to the differences in the natural gas burner tip price estimates examined.

Figure 13 and **Figure 14** illustrate similar WECC backcasts for PG&E and SoCal Gas burner tip prices but generally lower Energy Commission estimates. Price estimates at other western locations show similar trends, although these price estimates can differ by a larger or smaller amount.

Figure 13: WECC and Energy Commission Burner Tip Price Estimates (PG&E)

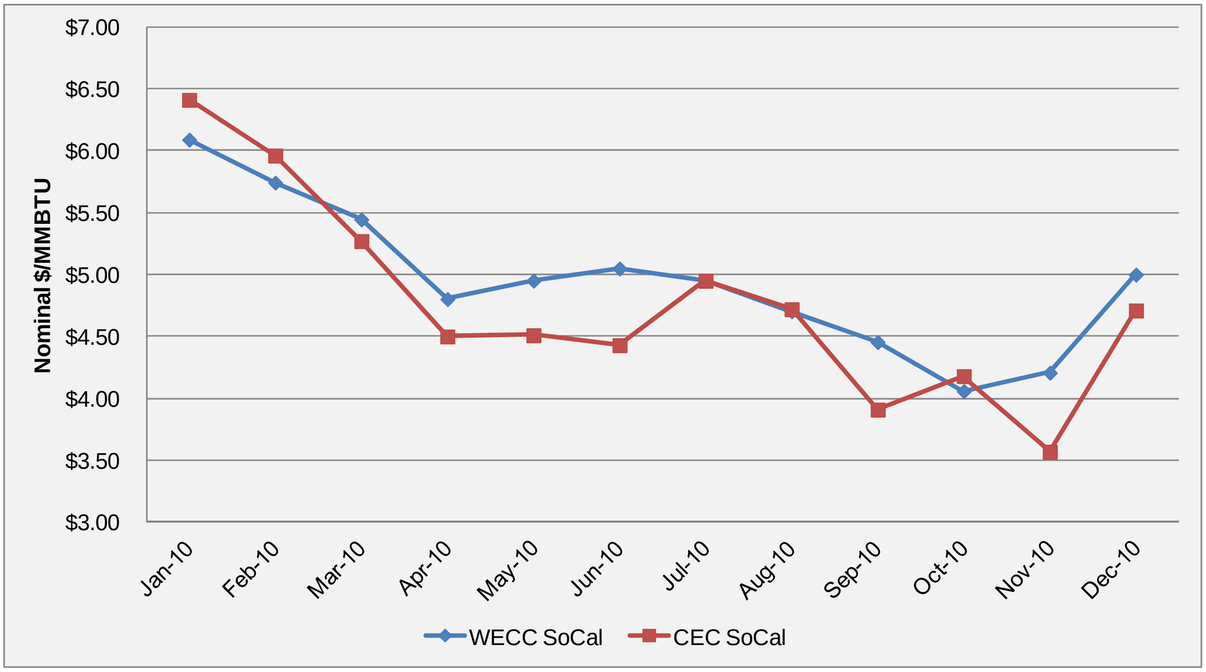


Source: WECC and Electricity Analysis Office staff.

Staff's burner tip price estimates for Northern and Southern Nevada fit reasonably well with the WECC backcast; however, the estimates for Southern Nevada appear to have a better fit; see **Figure 15** and **Figure 16.**

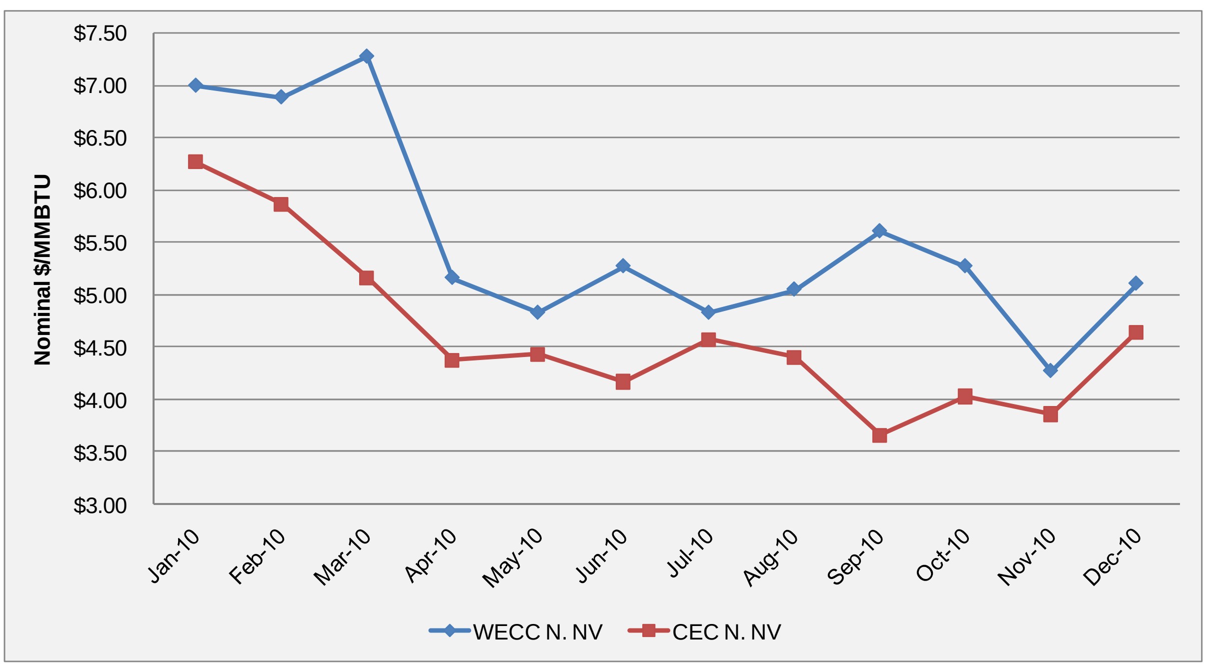
40 A *risk premium* means the extra amount paid to avoid the risk of increasing or volatile natural gas prices.

Figure 14: WECC and Energy Commission Burner Tip Price Estimates (SoCal Gas)



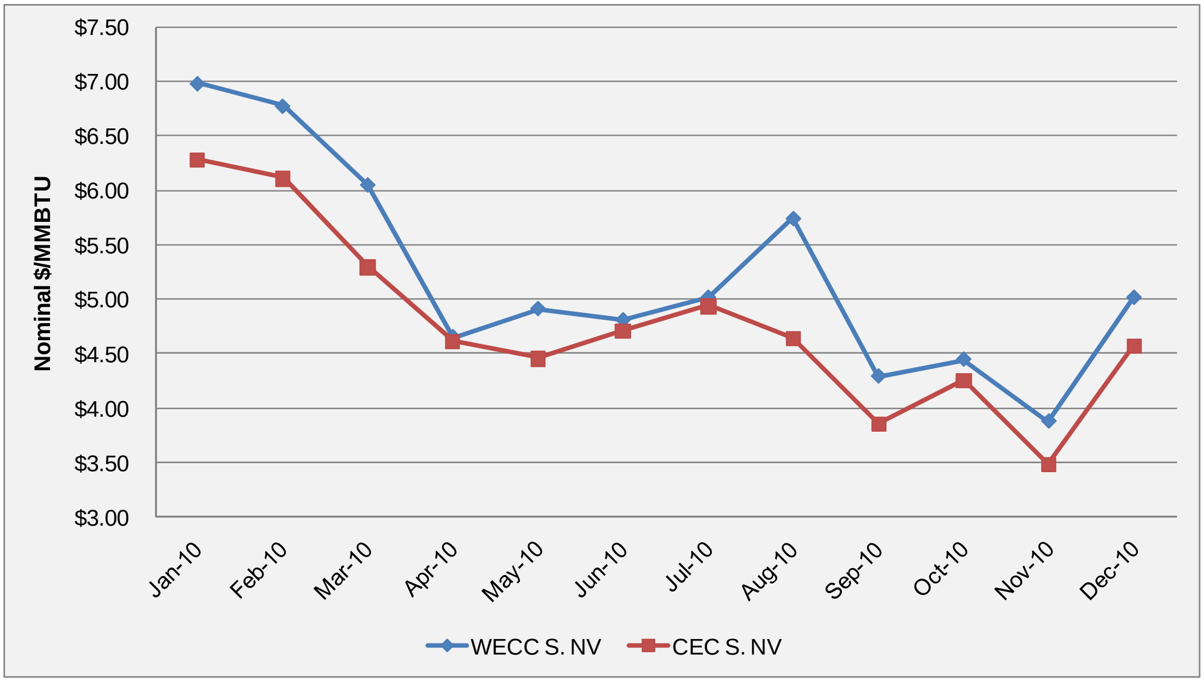
Source: WECC and Electricity Analysis Office staff.

Figure 15: WECC and Energy Commission Burner Tip Price Estimates (Northern Nevada)



Source: WECC and Electricity Analysis Office staff.

Figure 16: WECC and Energy Commission Burner Tip Price Estimates (Southern Nevada)



Source: WECC and Electricity Analysis Office staff analysis.

California Gas Utilities' *California Gas Report* Burner Tip Price Estimates

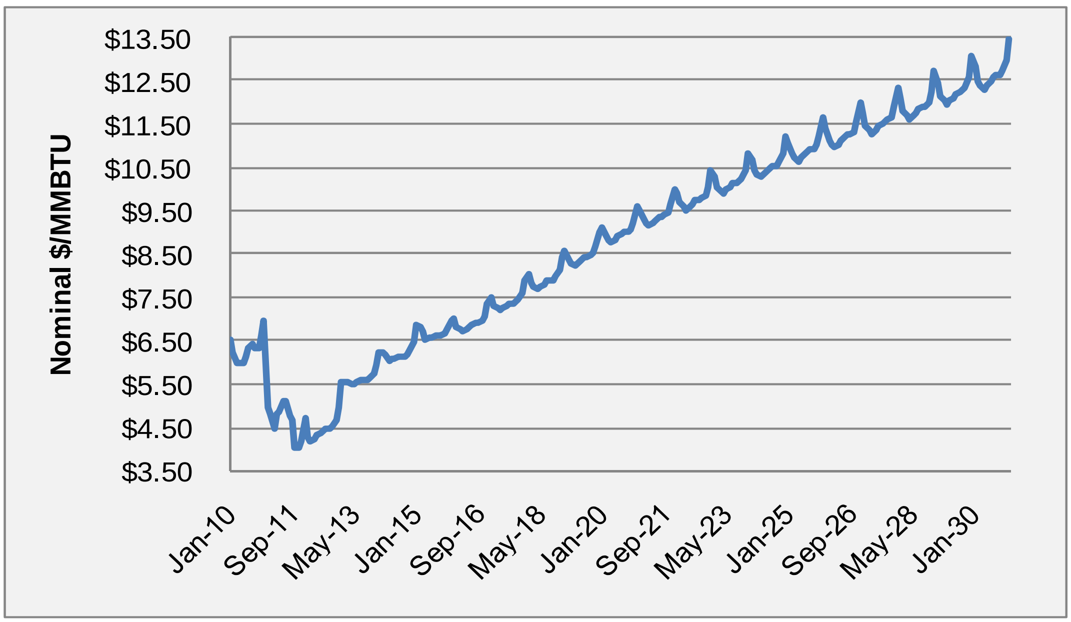
The *California Gas Report* estimates natural gas burner tip prices as part of its modeling effort. These price estimates are then used for modeling electricity generation dispatch. The *California Gas Report* burner tip price estimates represent usage for cogeneration and other industrial applications, as well as electric generation inside an oil refinery; thus, these estimates may differ slightly from other burner tip price estimates and assumptions. Electric generation inside an oil refinery may have different usage patterns than electric generation used for other applications, such as meeting base load demand or meeting peak loads.

For the natural gas commodity price forecast, the *California Gas Report* uses NYMEX Henry Hub futures contracts for the first 18 months of the forecast period and converts these to California border prices (California-Arizona border) using a basis swap.[41] A basis swap pays one party a fixed amount for the price difference between the Henry Hub price and a given delivery point while the other party receives the floating price differential. After the first 18 months, the *California Gas Report* looks at the average of a number of fundamental price forecasts provided by consultants, similar to the approach used in the CPUC's MPR.

41 For more on basis swaps, see http://www.think-energy.net/naturalgas.htm and www.theice.com.

For the transportation component of the forecast, the *California Gas Report* uses an intrastate transportation rate that is the average of transmission and distribution-level electric generation customers. The transportation rate is assumed to increase each year throughout the forecast period. There is also a GHG price adder added to the commodity price. The GHG adder is included to capture additional costs for refineries/electric generators as a result of new emissions regulations in Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006). The GHG adder for natural gas starts at $0.61/MMBtu in 2012 and increases to $3.42/MMBtu by 2030.[42] **Figure 17** shows the monthly *California Gas Report* burner tip price estimate for the SoCal Gas service territory. This is a burner tip price estimate for transmission/distribution-level electric generation customers in the SoCal Gas service area. The *California Gas Report* burner tip price estimates are similar to the NWPCC estimates in that there is an initial price drop from 2010–2012 and a steady increase after that. **Figure 17** shows a seasonal pattern; the prices are higher in the winter when natural gas demand is higher due to space heating demand. The seasonal pattern here also is similar to that of the NWPCC's estimates.

Figure 17: *California Gas Report* Burner Tip Price Estimates for SoCal Gas Service Territory



Source: http://www.socalgas.com/regulatory/documents/cgr/REDACTED%20SoCalGas%207%2025%2012.pdf.

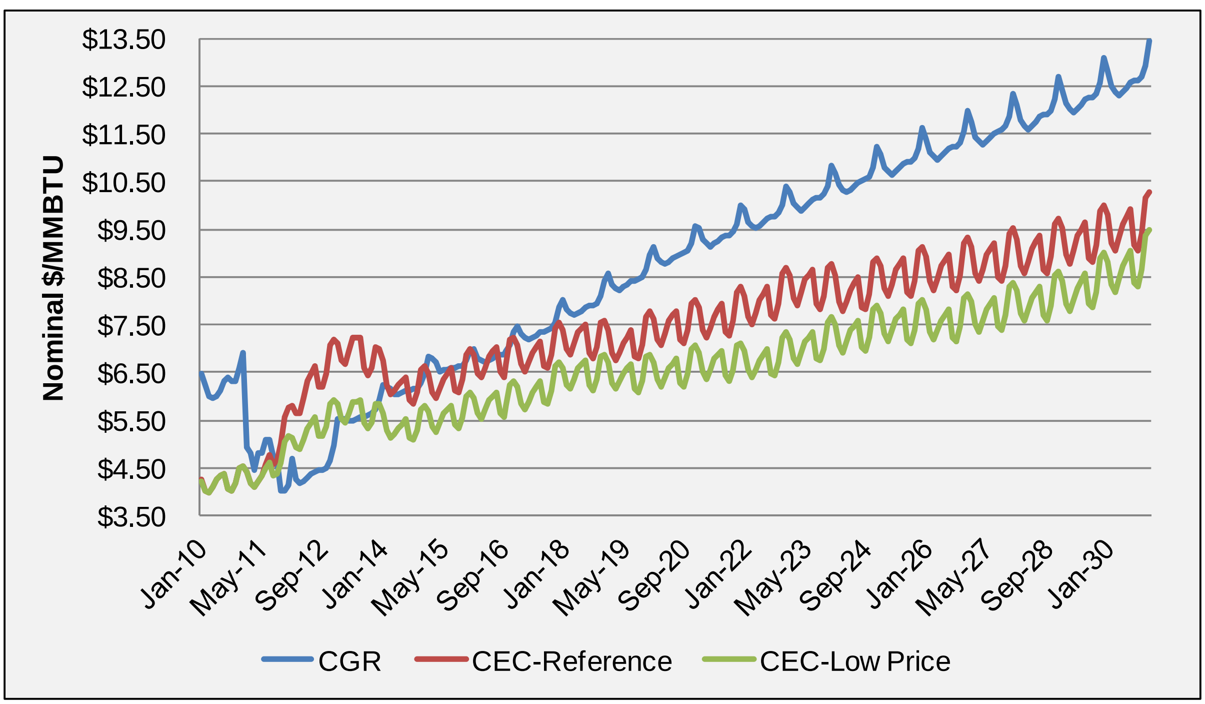
42 For more on the CGR burner tip price forecast, see Appendix A of this report and http://www.socalgas.com/regulatory/documents/cgr/REDACTED%20SoCalGas%207%2025%2012.pdf, pages 249-257.

California Gas Report Burner Tip Prices vs. Energy Commission (SoCal Gas)

The *California Gas Report* forecasts several economic parameters that go into power plant modeling, such as supply issues, demand response, efficiency, environmental policies, and so forth. The *California Gas Report* burner tip prices represent usage for cogeneration and other industrial applications, as well as electric generation inside an oil refinery; thus, they may differ slightly from other burner tip price estimates and assumptions.

Figure 18 compares the *California Gas Report* burner tip price estimates with the Energy Commission burner tip price estimates. Staff's burner tip price estimates are for gas-fired generators in the SoCal Gas service territory, while the *California Gas Report* estimates burner tip prices for industrial applications, cogeneration, and electric generation within oil refineries. Thus, this is not an apples-to-apples comparison. The main difference in the *California Gas Report* estimates and staff's estimates is the slope of the *California Gas Report* price plot. The *California Gas Report* price plot has a steeper slope (the prices increase at a greater rate); this can be partially explained by the *California Gas Report* adding a GHG price adders to its estimates and increasing the transportation rates over the forecast period (2010–2030). Secondly, the *California Gas Report* estimates a dip in the 2011–2012 period, which is more consistent with historical natural gas prices than the small bumps the Energy Commission's estimates show over the same period.

Figure 18: SoCal Gas Burner Tip Price Estimates,
***California Gas Report* vs. Energy Commission**



Source: SoCal Gas and Electricity Analysis Office staff analysis.

Ventyx Velocity Suite Energy Historical Burner Tip Prices

Ventyx provides burner tip price data going back to 1995.[43] The Ventyx historical burner tip prices originally come from EIA Form 923. Because the burner tip prices from Ventyx are for the power plant level, Energy Commission staff computed natural gas volume-weighted averages to derive prices for the California, Arizona, and Nevada regions. **Table 3** lists the number of power plants by region used to calculate the volume-weighted prices.

Arizona, California, and Nevada all show similar trends in their historical burner tip prices. These historical prices capture the price spikes that occurred in 2001–2002, 2005, and 2008. Also, these historical prices show decreasing natural gas prices and less volatility since the end of 2008. Arizona, California, and Nevada are broken up into northern and southern regions based on the geography of the power plants in each state. The price differences between the northern and southern regions for each state are negligible. Nevada showed the most price variation across its northern and southern regions. **Figure 19**, **Figure 20**, and **Figure 21** illustrate these findings. These prices will show some variation between regions as power plants in each region can procure natural gas from different price hubs and can procure pipeline capacity from different pipelines. Both of these factors will likely result in some price differences across regions.

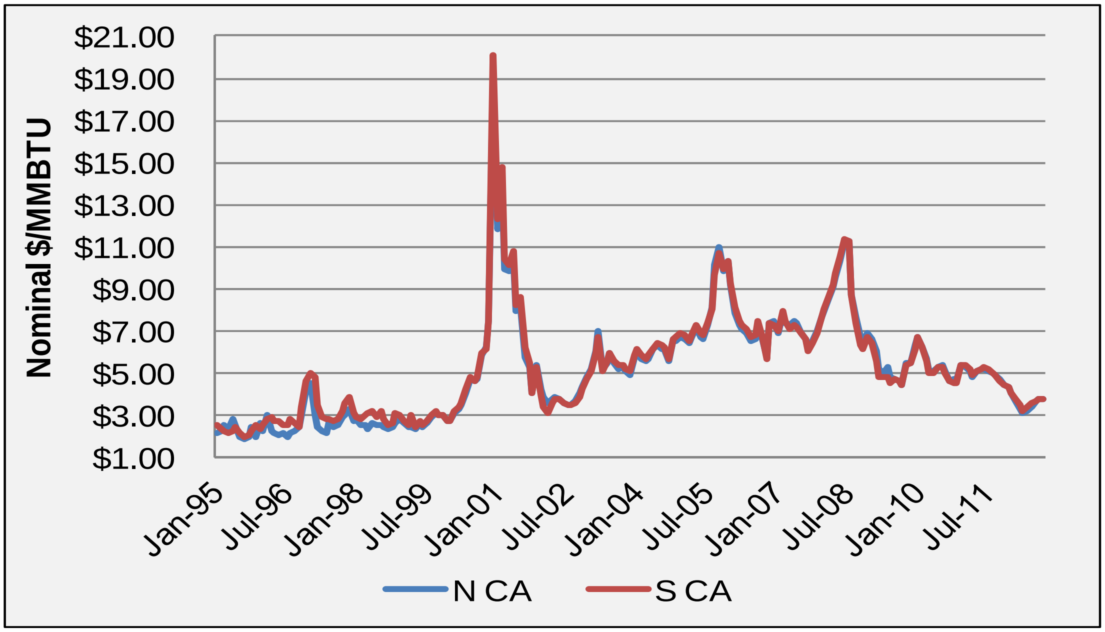
Table 3: Power Plant Counts in California, Arizona, and Nevada Areas

AREA	COUNT
Northern California	176
Southern California	173
Northern Nevada	6
Southern Nevada	17
Northern Arizona	4
Southern Arizona	28

Source: EIA Form 923 and Electricity Analysis Office staff analysis.

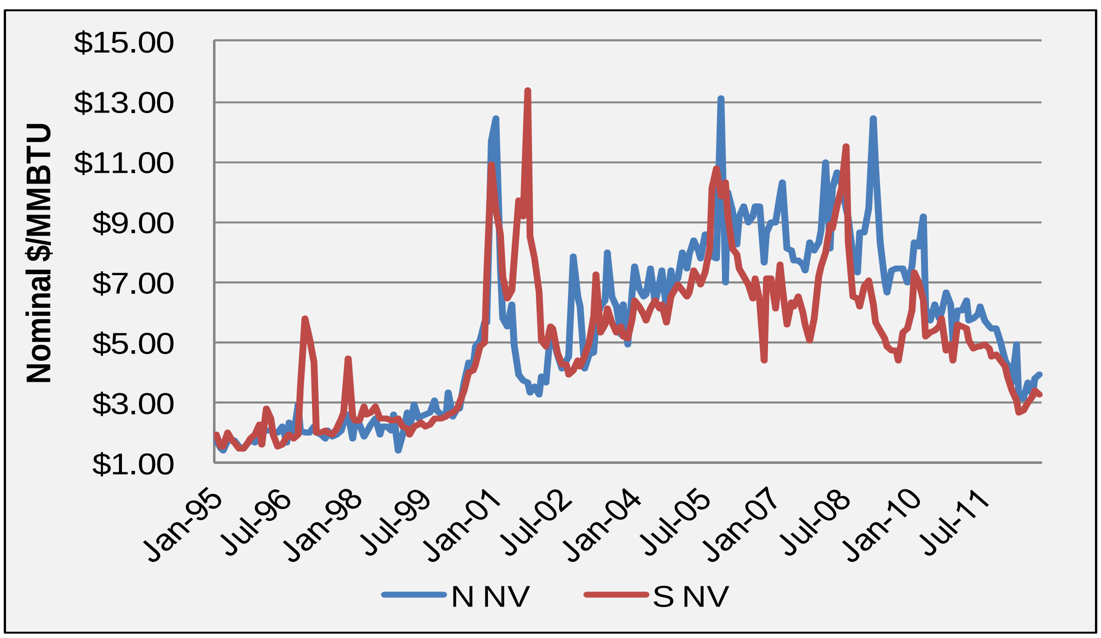
43 These historical prices come from Ventyx's Energy Velocity suite.

Figure 19: Ventyx Historical Burner Tip Prices for California



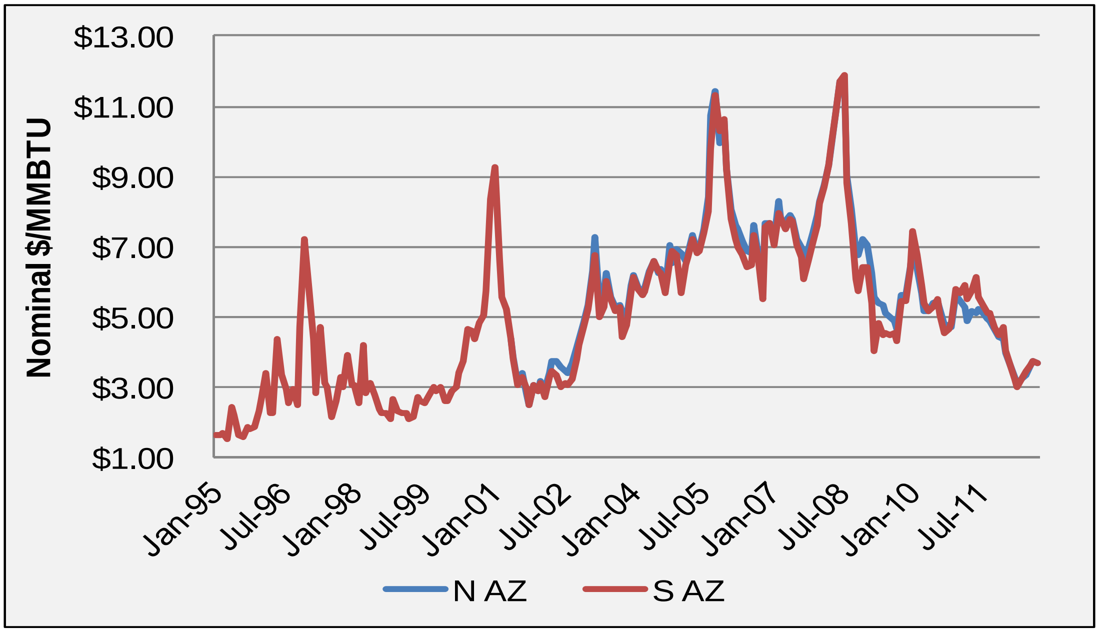
Source: Ventyx Velocity Suite.

Figure 20: Ventyx Historical Burner Tip Prices for Nevada



Source: Ventyx Velocity Suite.

Figure 21: Ventyx Historical Burner Tip Prices for Arizona



Source: Ventyx Velocity Suite.

Energy Commission Burner Tip Price Backcast vs. Ventyx Velocity Suite Historical Burner Tip Prices

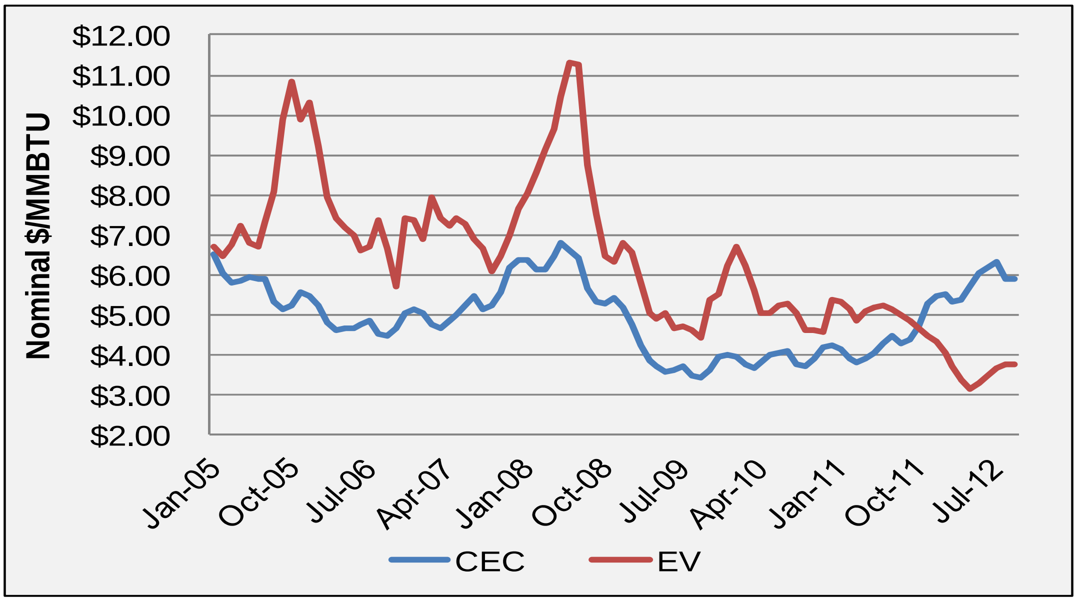
Staff compared historical burner tip prices from Ventyx to its own burner tip price estimates. This backcast comparison helps determine the accuracy of the staff's estimation methods and price results. The results of the backcast comparisons are mixed; for California, Arizona, and Nevada, staff's burner tip price estimates are consistently lower than the Ventyx historical prices.

In addition, staff's price estimates did not capture the natural gas price spike in September 2005 resulting from hurricanes Katrina and Rita or the full magnitude of the summer 2008 natural gas price spike. This is to be expected because the WGTM is a long-term model (producing annual outputs), and it is almost impossible to predict short-term price movements based on unexpected weather events or other unexpected short-term phenomena.

Finally, from the beginning of 2012, staff's price estimates increase, while Ventyx correctly shows prices decreasing over the same time. This discrepancy can be explained mainly as a forecasting error in the model; 2012 is seven years out from the first forecast year (2005), and the WGTM is set to run annually to provide more long-term trends in natural gas prices. Some amount of forecast error is expected. This discrepancy may be remedied in future natural gas price forecasts by running the WGTM on a monthly/weekly time frame to incorporate more short-run factors, such as weather-driven demand, supply shocks, and natural gas storage.

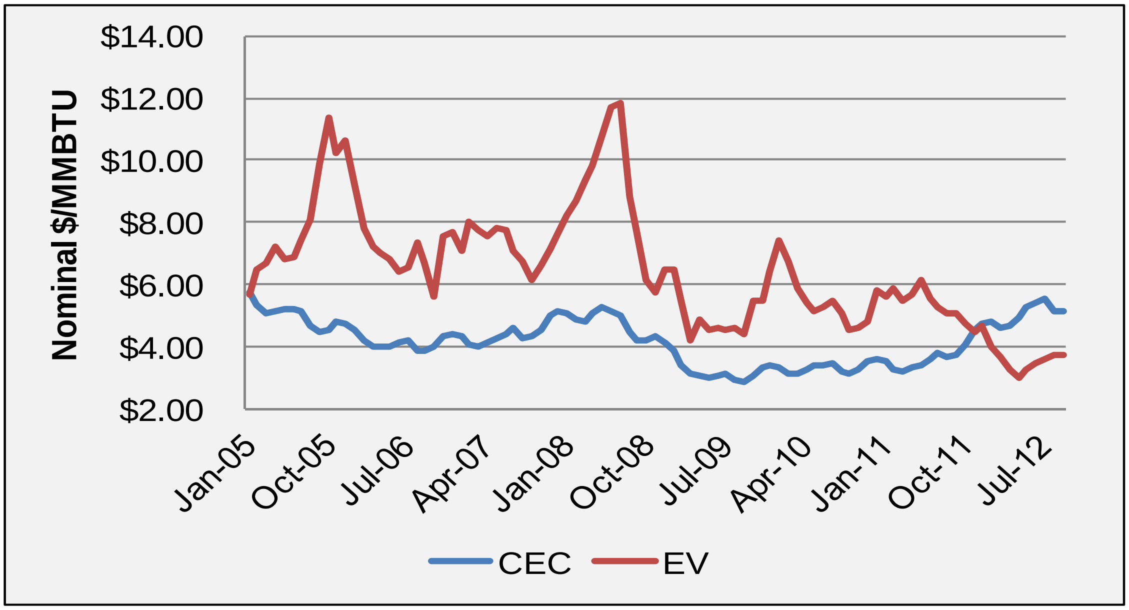
Other than the two unexpected price spikes and the last year of the backcast, staff's burner tip price estimates fit reasonably well to the Ventyx historical prices. **Figure 22**, **Figure 23**, and **Figure 24** illustrate these findings. On the figures below, "CEC" will denote Energy Commission estimates, while "EV" will denote the historical prices from Ventyx.

Figure 22: Backcast of California Natural Gas Burner Tip Prices



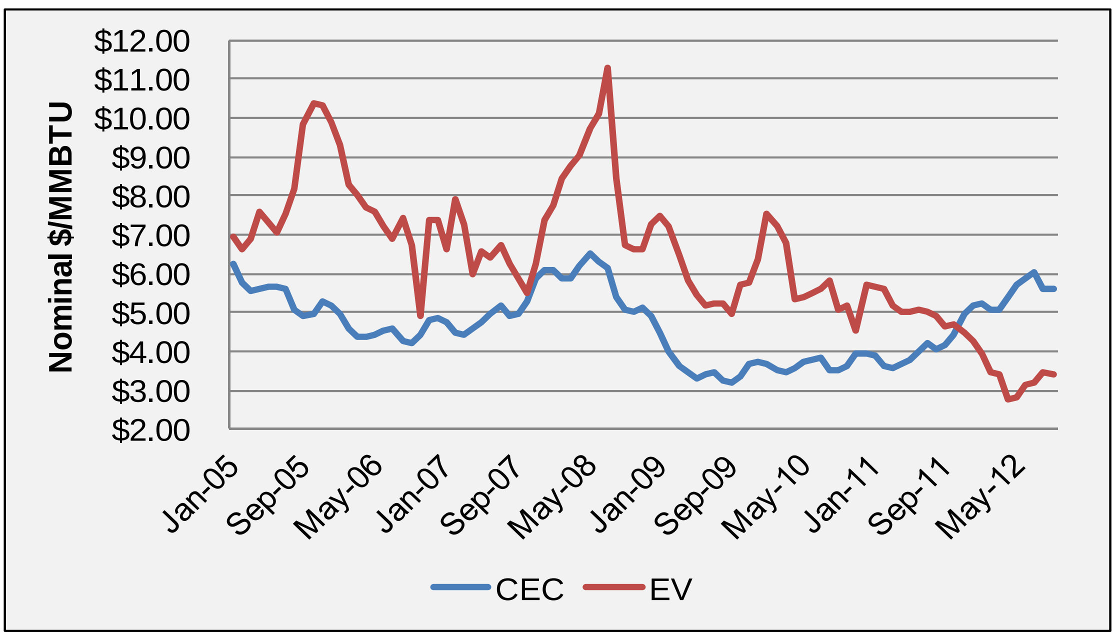
Source: Ventyx Velocity Suite and Electricity Analysis Office staff analysis.

Figure 23: Backcast of Arizona Natural Gas Burner Tip Prices



Source: Ventyx Velocity Suite and Electricity Analysis Office staff analysis.

Figure 24: Backcast of Nevada Natural Gas Burner Tip Prices



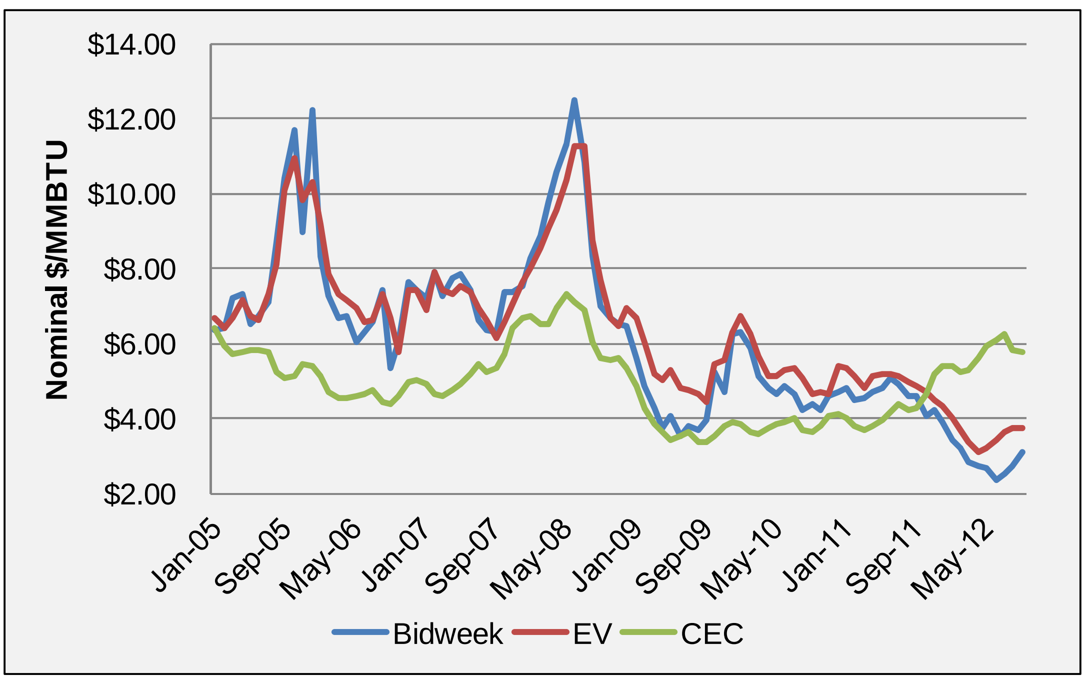
Source: Ventyx Velocity Suite and Electricity Analysis Office staff analysis.

Because staff's price estimates showed some difference from the Ventyx historical prices, staff added to the comparison burner tip price estimates that use historical bid week prices as the commodity price of natural gas and the same transportation rates that staff used in its burner tip price estimates. Historical bid week prices come from *Natural Gas Intelligence*. Bid week prices are used as this is how most natural gas is procured for power plants core activities. For Northern California, the PG&E citygate price was used while for Southern California, the SoCal Gas Citygate price was used. Staff may make similar comparisons, in the future, with other subregions in the WECC.

As expected, the burner tip price estimates using the bid week commodity prices fit well with the Ventyx historical burner tip prices. This shows that most of the difference between staff's and Ventyx's prices are a result of forecasting errors in the WGTM. The WGTM is set up to run annually and capture long-term trends; short-term trends such as price spikes do not show up with the same level of detail as the bid week price estimates or the Ventyx historical prices. **Figure 25** and **Figure 26** illustrate these findings. These results are similar for Arizona and Nevada as well. **Figure 25** and **Figure 26** both suggest that the bid week price is a good approximation of how much gas-fired generators pay for the commodity portion of the burner tip natural gas price.

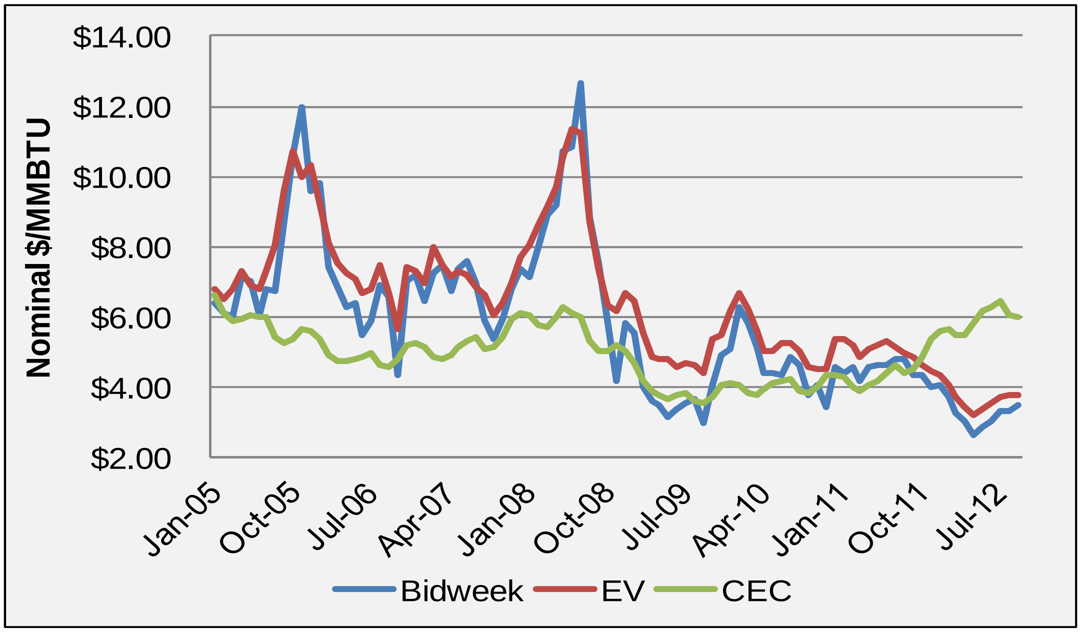
Possible solutions to remedy the price differences between staff's estimates and the Ventyx and bid week prices include running the model monthly rather than annually and running scenarios with short-term supply/demand shocks such as hot and cold weather events. It is impossible to eliminate all the forecast error; thus, running sensitivities helps account for some of this uncertainty.

Figure 25: Northern California Burner Tip Prices, Ventyx vs. Energy Commission



Source: Ventyx Velocity Suite and Electricity Analysis Office staff analysis.

Figure 26: Southern California Burner Tip Prices, Ventyx vs. Energy Commission



Source: Ventyx Velocity Suite and Electricity Analysis Office staff analysis.

Staff's burner tip price estimates fit reasonably well with the other estimates and historical prices. There are a few instances early in the forecast time horizon (2012–2014) where staff's estimates diverge from the *California Gas Report* and the NWPCC estimates; however, the overall fit is good.

Staff's burner tip price estimation method uses price output from the WGTM model, while other methods use data that are publicly available. Publicly available data include Henry Hub commodity prices, NYMEX futures contract prices, and financial basis swap data (for interstate transportation costs). One advantage of using publicly available data is that more stakeholders may be willing to participate, reproduce staff's estimates on their own, and offer suggestions to the method and ideas about potential future work.

The WGTM provides output for many price hubs that are not publicly available; this allows for more options to choose different price hubs for the commodity price portion of the estimates. Another advantage is the WGTM produces price output based on supply and demand fundamentals rather than on NYMEX futures or other financial prices. Financial prices may capture mostly short-term price movements that are not completely based on supply-and-demand relationships. All the methods start with annual prices and convert to monthly values; each method may better capture short-term and seasonal phenomena by using monthly commodity prices instead of annual prices.

CHAPTER 4: Conclusions, Next Steps, and Potential Future Work

Lessons Learned

Natural gas burner tip prices are difficult to precisely estimate for a variety of reasons. Gas-fired generators can purchase their natural gas from multiple price hubs; it is unknown which hub or combination of hubs is used. Staff also does not know how much natural gas is purchased on the spot market, bid week contract, and short- or long-term contracts. Short-term events, such as extreme weather conditions and natural gas infrastructure maintenance and repair, cannot be accurately predicted. These types of events will affect both natural gas commodity prices and transportation rates. These uncertainties in estimating future prices need to be acknowledged and presented transparently along with the burner tip price estimates themselves.

There are many types of natural gas pipeline transportation services, all with different rate structures and terms of agreement. It is not possible to obtain detailed data on the types of pipeline services to which each gas-fired generator subscribes. Much of the gas-fired generator-level data on natural gas prices and transportation are confidential.

Next Steps

Staff invites feedback from interested stakeholders, including WECC, the natural gas utilities, merchant gas-fired generators, other load-serving entities, and the interstate pipeline companies. Getting stakeholder feedback can help staff refine its method for estimating burner tip prices. Stakeholders are encouraged to continue providing feedback on staff's burner tip price estimation method in regard to transportation rates, commodity prices, and other assumptions and caveats that can affect burner tip prices. Stakeholder feedback may include (1) how merchant natural gas power plants procure natural gas and transportation compared to utility-owned plants, (2) transportation rate forecasts, and (3) how natural gas and transportation procurement for gas-fired generators is expected to change with more intermittent renewable energy connecting to the grid. Stakeholders may provide staff data on gas-fired generators operating characteristics, like capacity factors and historical burner tip prices. Staff's methods can be published to provide a forum for stakeholders to submit written comments.

All of the feedback and input may inform future improvements to staff's method, including the addition of sensitivities on the cost of transportation and the commodity price of natural gas. Involving industry stakeholders will provide more transparency to staff's method. Adding transparency and stakeholder input to staff's method can make it both more defensible and robust. Various forums should be sought out so stakeholders can provide feedback and input.

Potential Improvements

Going forward, work can be done to improve the forecasting and estimation method employed by the Energy Commission. The following list of refinements and improvements is by no means exhaustive. It reflects areas where additional information, further refinement, or more analytic resources may lead to improved results.

Learn More About Gas Procurement

First, staff can contact and survey industry stakeholders (natural gas utilities, owners/operators of merchant natural gas-fired generators, and owners/operators of natural gas pipelines) to gain a better understanding of how natural gas is procured and what gas-fired generators pay for the commodity natural gas. Determining the amount of long-term, short-term, and other types of natural gas purchases will help to reflect more accurately how power plants procure natural gas and how much they pay for the commodity itself. Secondly, different types of natural gas power plants may not purchase natural gas in the same manner. For example, merchant plants may procure natural gas much differently than utility-owned power plants. Peaker power plants may also procure gas differently than base load power plants. Staff can provide a more detailed analysis with different commodity pricing assumption for merchant and utility-owned power plants.

Explore Other Price Data Services

For the commodity component of the burner tip price estimates, the Energy Commission uses data from *Natural Gas Intelligence* for backcasting and data from the WGTM model for future prices. The Energy Commission, in the future, could explore other natural gas price data services, such as *Energy Intelligence* (www.energyintel.com), to gather more natural gas price data. Gas-fired generators can purchase their fuel from a variety of natural gas hubs; taking a weighted average of a set of hubs may better represent this fuel cost. Staff can also gather information on long-term natural gas supply contracts and incorporate this gas purchase strategy into its estimates. A gas-fired generator that purchases gas through long-term contracts can pay either more or less than natural gas purchases on the spot market or through monthly bid week contracts.

Research How Transportation Costs Vary With Different Ownership Types

Staff assumes that all transportation used by gas-fired-generators is firm capacity rather than interruptible and no real growth rate in the transportation rates. These assumptions have worked well thus far, but there may be differences in transportation cost and procurement among natural gas power plant ownership types. Merchant power plants may purchase more types of transportation services than utility-owned power plants; these two power plant types may pay different amounts for their transportation. Peaker and base load gas-fired generators may have different costs for transportation also. Adding this detail to staff's method may better reflect reality and may result in more realistic dispatch decisions when the burner tip prices are used for production cost modeling.

Investigate Historical Transportation Growth/Decline Rates

Transportation rates generally change over time, although with no consistent pattern. Staff has discussed adding growth/decline rates to the transportation rates to capture the increase in rates over time. The CPUC's MPR uses a transportation growth rate of 1.81 percent per year. Staff can look at historical transportation rates from various pipelines/utilities to develop a transportation growth rate/decline rate. Staff could also use an average of the last three to five years of transportation rates instead of using the most current rate. This can help remedy some of the increase/decrease of rates in recent history. Using an average rate over the last few years may provide a better long-term transportation rate, as using the most current rate can result in a peak or a valley that is about to change direction.

Request Transportation Rate Forecasts

Another option is to contact California utilities and natural gas pipeline operators that supply natural gas into California and western states and ask them to provide transportation rate forecasts. Collecting transportation rate forecasts can be adopted as regulations for future *Integrated Energy Policy Report (IEPR)* cycles. Pipeline operators understand their pipeline system, including maintenance schedules, pipeline upgrades, and replacement needs going forward. Power plants can be surveyed to find out what they pay for transportation, what type of transportation they procure (long-term, firm, interruptible, and so forth), and from which pipeline/pipelines they procure transportation. Staff's method will likely produce more realistic burner tip price estimates if it has more accurate assumptions on what power plants pay for natural gas transportation.

Produce Monthly Gas Price Estimates Using WGTM

Another way to improve the Energy Commission burner tip price estimates is to run the WGTM monthly rather than annually. Running the WGTM monthly eliminates the need to convert annual prices to monthly values; however, natural gas storage now needs to be added in the WGTM. Running the WGTM monthly with natural gas storage included requires additional staff time but will provide staff insights to the seasonal aspects of the natural gas market (including storage injections and withdrawals). The WGTM can be run to produce natural gas prices for any period (year, month, week, day, and so forth); smaller time increments such as days may be of less use for longer-term forecasting (20 years and more). Staff will discuss running the model this way and determine if this use of time will benefit the analysis.

Use Scenario Analysis

Scenarios should be included that look at future severe weather events and extended outages of natural gas infrastructure, as well as other scenarios that will affect future natural gas burner tip prices. Running various scenarios helps account for future uncertainty and can provide insights into how unexpected events will impact future burner tip prices. Having an ensemble of burner tip price estimates based on various scenarios will make the Energy Commission's methods and estimates more robust and provide flexibility for electricity system planners who want to consider more than one future scenario.

Conclusions

Having a burner tip price estimation method that is documented and transparent will allow feedback from stakeholders and the ability to improve the Energy Commission's method over time. Other agencies who use burner tip prices in their modeling, such as the WECC, may find use in the Energy Commissions' methods.

The assumptions and the estimated burner tip prices from industry stakeholders and Energy Commission staff are roughly in line with each other. Differences center on transportation rate estimation and commodity price development. Staff's method uses a general equilibrium model (WGTM) to produce natural gas commodity prices, while other agencies use NYMEX futures Henry Hub or wellhead prices. The Energy Commission uses both interstate and natural gas utility intrastate firm transportation rates, while other methods use basis swaps or historical basis differentials to account for transportation costs.

Staff's burner tip price estimates match reasonably well with those from other industry stakeholders, such as the CPUC, WECC, and the NWPCC. Historical burner tip prices also match up fairly well with staff's estimates. No estimates performed well in capturing price spikes due to weather or other short-term events. It is impossible to consistently and accurately predict future weather events and other short-term future phenomena that affect natural gas burner tip prices.

Using staff's estimation method on historical bid week natural gas commodity prices with the firm transportation rates of the pipelines and natural gas utilities matches very well with historical burner tip prices from Ventyx.[44] This finding supports the Energy Commission's use of firm transportation rates to represent the cost of transporting natural gas. Assuming

44 See Chapter 3, **Figure 25** and **Figure 26**.

all pipeline capacity is firm may be a reasonable assumption. Historical data from EIA also support the use of firm transportation over interruptible transportation.

Natural gas is expected to play an important role in electricity system planning along with integrating renewable energy for the foreseeable future. It will be important to keep staff's burner tip price estimation method up-to-date, including the commodity price forecasts and transportation rates. Performing this analysis at least every two years should keep the methods and assumptions updated.

Acronyms

Acronym	Definition
$/MMBtu	Dollars per million British thermal units
CPUC	California Public Utilities Commission
EIA	Energy Information Administration
Energy Velocity	Ventyx's Energy Velocity Suite
FERC	Federal Energy Regulatory Commission
ICE	Intercontinental Exchange
MPR	Market Price Referent
NWPCC	Northwest Power and Conservation Council
NYMEX	New York Mercantile Exchange
PG&E	Pacific Gas and Electric Company
SoCal Gas	Southern California Gas Company
Ventyx	Ventyx Velocity Suite
TEPPC	Transmission Expansion Planning Policy Committee
WECC	Western Electricity Coordinating Council
WGTM	Rice World Gas Trade Model

APPENDIX A: Discussion of Methodology of Annual to Monthly Conversion Factors

There are two components in converting annual natural gas prices to monthly values: a seasonality component and year-to-year interpolation component. Together, both of these components will be called an annual-to-monthly conversion factor (conversion factor).

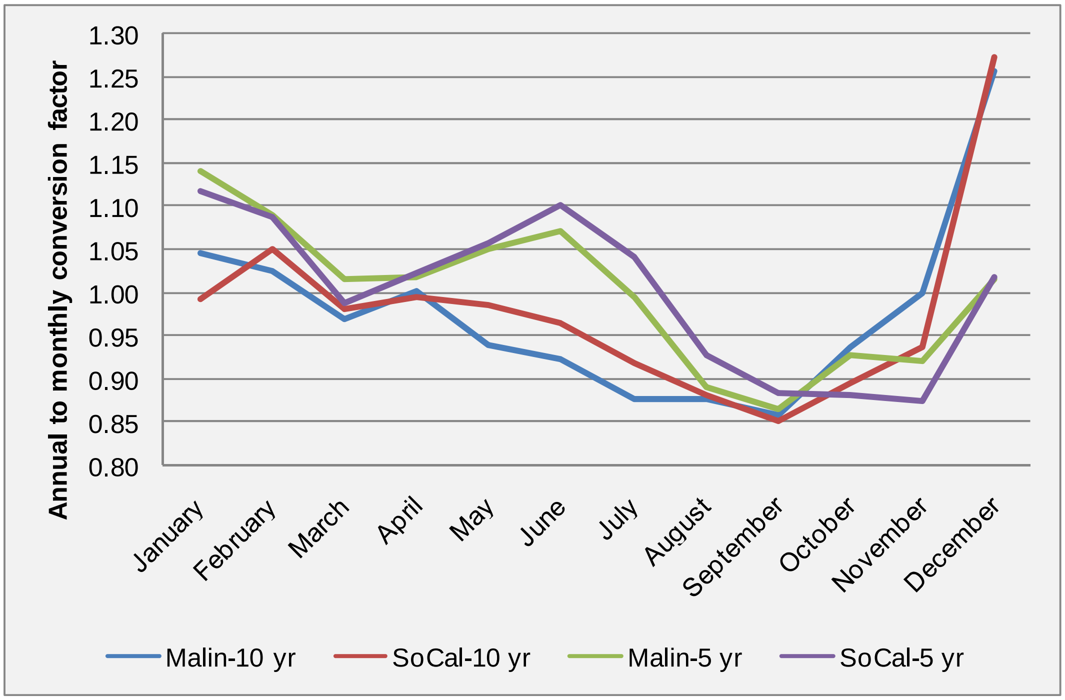
Seasonality

The WGTM outputs annual natural gas prices. To obtain a more granular look at natural gas prices coming from the model, staff converted the annual prices to monthly values. Historical annual average and monthly natural gas prices at select pricing points were compared and a seasonal factor calculated for each month. Staff took averages of these factors over 5, 10, 15, and 20 years. Ultimately, staff decided on the 10-year average (2001–2011) of Henry Hub-derived seasonal factors because it fits the data well and represents the most current 10 years of data. Some of the other seasonality factors fit the data better in certain years, but over the whole 2001–2011 period, the 10-year Henry Hub average had the best fit.

Staff examined seasonal factors based on regional prices. **Figure A-1** shows the 5- and 10-year average seasonal factors for the Malin and SoCal Gas border price points, both in California.[45] Higher volatility is apparent in these seasonal factors compared to the ones derived from Henry Hub prices, particularly in the winter months. The volatility seen in the winter months may be the result of cold winters experienced by the United States in the early 2000s. The 5-year seasonal factors do not show the same magnitude of volatility in the winter months; however, they show more volatility in the summer months. In the 5-year seasonal factors, the summer 2008 price spike is a larger percentage of the average seasonal factor than are the 10-year price spikes. Seasonal factors from other regional pricing points were also more volatile than the Henry Hub-derived seasonality factors and showed similar results.

45 The 5-year average is from 2007–2011, and the 10-year average is from 2001–2011.

Figure A-1: California Annual to Monthly Seasonality Factors



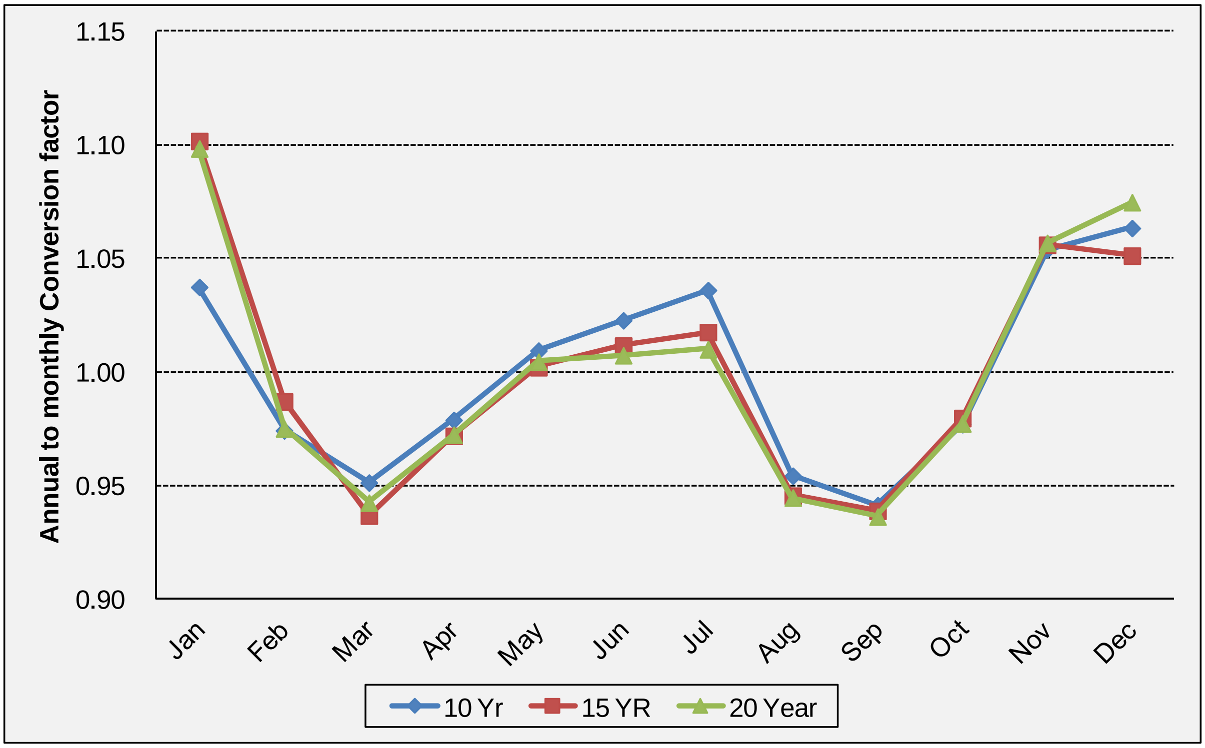
Source: *Natural Gas Intelligence*, bid week price data.

The seasonal factor is a number multiplied by the annual natural gas price to get the monthly natural gas price for each calendar month. To obtain the seasonal factor number, simply divide the monthly natural gas price by the annual natural gas price for a given natural gas price hub; in this case, it is the Henry hub. For instance, if the January seasonal factor were 1.10, multiply the annual natural gas price by 1.10 to get the January monthly price. This result says that the January monthly price is 10 percent higher than the average annual price.

The formula for the seasonal factor is monthly gas price/annual gas price for each month. Then, each monthly seasonal factor is averaged over the 10-year time span. Once the January factor for each year was found, the factors were averaged to get one January seasonal factor. All other months are computed the same way.

Figure A-2 illustrates three Henry Hub seasonal factors for each month. All three seasonal factors are very similar and follow a distinct pattern. The seasonal factors spike in the summer and winter months; the winter spike is larger than the summer. These two spikes represent increased natural gas use for both cooling and heating load demand. One reason the Henry Hub seasonal factors are less volatile than the California seasonal factors is that the Henry Hub is a very liquid price hub and is considered a national benchmark price; the liquidity insulates some of the price shocks more than other, less liquid, price points.

Figure A-2: Henry Hub Annual to Monthly Seasonality Factors



Source: *Natural Gas Intelligence*, bid week price data.

Interpolation

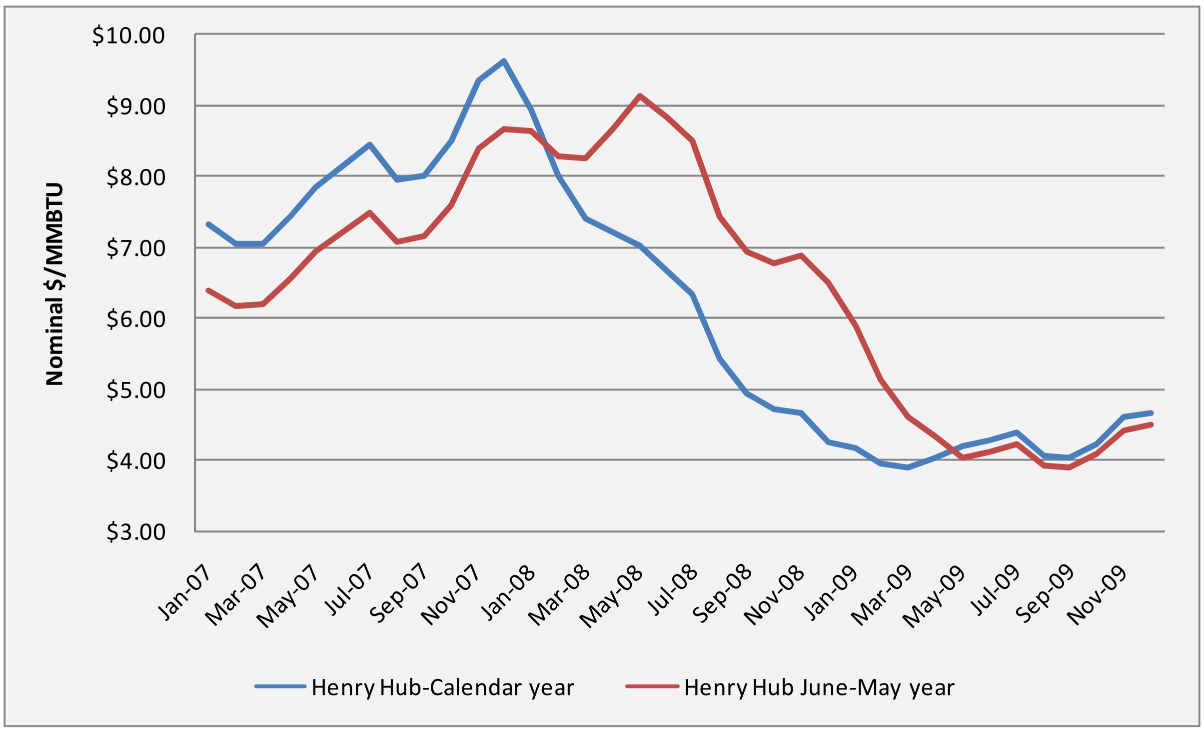
The second component of converting natural gas prices from annual to monthly values is interpolation. Moving from one year to the next, staff examined two methods for interpolation. The first method uses a calendar year (January through December), while the second method uses a year that goes from June through May.

The June-through-May year method was chosen after investigating both methods. This method was chosen because the seasonal factor was closest to 1 in June. This helps remedy the price jumps from December to January, which occur in some years between the December to January prices when using the other method. The chosen method also had a better fit to historical data.

In both methods interpolation is assumed to be linear. (The increase/decrease of prices occurs uniformly between years). Staff understands that prices may not always behave like this, but makes this simplifying assumption. For instance, the annual Henry Hub natural gas price was $6.86 in 2007 and $9.04 in 2008. The price difference between the two years is $2.18. Each month from January through December would have added to it $2.18/12 or $0.18. January would be $6.86+$0.18 = $7.04, February would be $7.04+$0.18 = $7.22, and so on. The December 2007 price, in this example, is $9.04, which is the same as the annual 2008 price. This method works fairly well most of the time.

The following example converts annual Henry Hub prices to monthly values for 2007–2009. This example uses the January-December year and June-through-May year interpolation methods, as well as the seasonal factors. The average annual Henry Hub prices for 2007, 2008, and 2009 are $6.86, $9.04, and $3.99, respectively. The full conversion first converts the annual prices to monthly values using the seasonal factors discussed above; then each monthly price has added to it a linear interpolation value to account for the year-to-year price changes. **Figure A-3** illustrates this point. There are two main takeaways from this graph. First, the calendar year-estimated natural gas prices have a steep drop from December 2007 to January 2008; this drop is mainly the result of using the calendar year for interpolation. Secondly, the method that employs the June-through-May year interpolation more accurately captures the high natural gas prices in summer 2008. Although both of these estimates are similar, the June-through-May year estimates tend to fit historical price data better than the calendar year estimate.

Figure A-3: Henry Hub Estimated Prices, Calendar Year vs. June Through May Year



Source: *Natural Gas Intelligence*, bid week price data, and Energy Commission staff analysis.