Community Environmental Council

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April 30, 2008

California Energy Commission
1516 Ninth Street
First Floor, Hearing Room A
Sacramento, California

Re: Docket number No. 08-IEP-1, 2008 and 2009 Integrated Energy Policy Report

Dear Energy Commissioners,

The Community Environmental Council is an environmental non-profit organization founded in 1970 in Santa Barbara. Our primary mission is to wean our region from fossil fuels (www.fossilfreeby33.org). We hope our detailed regional energy model will be adopted far and wide, achieving widespread change. For our regional plans to be effective, we must help ensure favorable state energy policies, hence our role in the 2008 and 2009 Integrated Energy Policy Report proceeding.

We have been involved in the last two IEPR cycles and applaud your efforts and your clear commitment to smart energy policy in California. We have expressed ongoing concerns, however, with certain aspects of previous IEPRs and we strongly urge the Commission to re-consider the scope of the 2008 IEPR update as well as the 2009 IEPR.

33% by 2020 RPS

First, we would like to elaborate on the proposed focus in the 2008 Update regarding the state's 33% by 2020 Renewable Portfolios Standard (RPS). We strongly support this RPS goal[1] and are concerned that some Commissioners have publicly expressed concerns about achieving this goal. A preliminary analysis by the Center for Resource Solutions in 2005, for the CPUC, found that achieving this goal was achievable and would likely result in net savings to ratepayers.[2]

Transmission constraints are being resolved through construction of new lines from Tehachapi and Imperial Valley, and the RETI process is attempting to identify additional necessary transmission for renewable energy facilities over the next decade.

[1] We note also that the Solar and Clean Energy Act of 2008 will very likely be on the ballot in November of this year and will require, if passed, a 40% by 2020 RPS and a 50% by 2025 RPS by 2025.
[2] Online at: http://www.resource-solutions.org/lib/librarypdfs/Achieving_33_Percent_RPS_Report.pdf.

Technology costs for renewables are becoming more and more favorable. A recent report by your own Commission as part of the 2007 IEPR found that the levelized costs for renewable generation, including wind, geothermal, biomass and small hydro, were substantially lower today than electricity from combined cycle natural gas plants. Consultants working for the Environmental Council, from UC Berkeley, CalPoly San Luis Obispo, and UC Santa Barbara, projected that these cost differentials would substantially increase by 2030 (*see* Figure 1). Strong support for these projections comes from the 45% price increase for natural gas in 2008 alone, from less than $8/MMbtu to over $11/MMbtu (and expected continuing high prices in light of rising demand and stagnant supply increases, with very limited available LNG due to even high natural gas prices in Europe and Asia).

Figure 1. *Cost of electricity generation technologies in 2007, 2020 and 2030.*[3]

Technology	Cost in 2007	Cost in 2020[12]	Cost in 2030[13]
Biomass (landfill gas)	4.4	4.4	4.4
Geothermal	6.6	5.5	4.5
Wind (class 5)	6.6	6	6
Advanced nuclear	7.4	9.3	11.4
Baseload natural gas (combined cycle)	9.4	13.22	17.66
Coal w/ gasification	9.6	10.9	12.1

A related and necessary analysis that should be included in the 2008 Update is the degree to which new natural gas plants will crowd out renewables. We recently wrote in comments for the CPUC's long-term procurement proceeding (R.08-02-007):

> Under some scenarios, literally all new generation built in California through 2020 will need to be renewable in order to meet this goal.

[3] From Chapter 8 of our Santa Barbara County energy blueprint, A New Energy Direction (Dec. 2007), available at www.fossilfreeby33.org.

> Renewable energy facilities produced about 32,000 GWh in 2006 (the latest figures available from the Energy Commission).[4] With electricity demand projected to be about 330,000 GWh in 2020,[5] up from 289,000 GWh in 2008, the 33% will require about 110,000 GWh. Accordingly, we will need to construct new renewable energy facilities sufficient to supply about 78,000 GWh of electricity by 2020 (110,000 minus 32,000). Under these projections, only 41,000 GWh of new electricity production could be met with new renewable resources without retiring any existing power plants.
>
> The rate of retirement of natural gas and coal plants becomes very important under this scenario. In order to meet the 33% RPS, 37,000 GWh of existing non-renewable generation will have to be retired (78,000 minus 41,000). Alternatively, natural gas plants that are used today as baseload or shoulder facilities could be used only as peak facilities or only to balance intermittent resources like solar and wind power.[6]

The Commission should add its weight to the discussion about what will be necessary to achieve the 33% target. The risk of over-procurement of natural gas generation is now very significant and may burden ratepayers with large stranded costs, particularly if Community Choice Aggregators, Direct Access customers (as this option is revived by the CPUC) and other departing load leaves the investor-owned utility system.

Peak oil and peak exports

This issue cannot be downplayed in terms of its importance. The scoping memo in this proceeding indicates that supply issues will be examined in the 2009 IEPR, but **we strongly urge the Commission to include this analysis in the 2008 Update and clarify that the examination should focus on short- and medium-term supply and price problems from a state policy level, as well as a local government planning level**.

The national economy and our state's economy are highly dependent on cheap oil. Even at $4/gallon gasoline and $4.50/gallon diesel (based on $120/barrel oil), petroleum costs are still a fairly small part of most household budgets. But credible forecasts of future prices and availability indicate that today's prices (perceived as extremely high because they are historical records even when adjusted for inflation) will in just a few years seem quite low.

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[4] California Energy Commission, Net System Power Report 2006, p. 4 (April 2007). Online at: http://www.energy.ca.gov/2007publications/CEC-300-2007-007/CEC-300-2007-007.PDF.
[5] California Energy Commission, California Energy Demand 2008-2018, Staff Revised Forecast, p. 12 (Dec. 2007).
[6] Submitted on March 17, 2008, available at: http://docs.cpuc.ca.gov/efile/CM/80412.pdf.

Deutsche Bank analysts stated just this month that oil could easily go to $200/barrel by the end of this year.[7] Such a price would be equivalent to about $7/gallon gasoline.

What is behind this recent trend in surging prices? Many factors are responsible, including a declining dollar, surging demand in China and India, and continuing unrest in major producers like Nigeria and Iraq. However, the declining dollar's influence is quantifiable. When we see that oil has risen 60% in the last year even when denominated in euros (and much higher in dollars),[8] it is clear that **the dollar's decline against other currencies is far from the only factor at work**.

There is a growing awareness that today's record prices (up literally 1,200% over the last ten years) are due to a systemic imbalance between supply and demand.

This is not a radical view. In fact, it's supported in some manner by the IEA, EIA, US Army Corps of Engineers, T. Boone Pickens, many oil company CEOs and many other analysts. Some of these entities believe we have reached, or are near, a global peak in oil production,[9] while others see a plateau arriving soon and sustaining itself for a while. More importantly, the conversation is clearly trending toward the former view as more and more serious analysts look at decline rates for fields around the world and compare them to planned projects. It's becoming increasingly clear that new projects will probably not be able to keep up with increasing decline rates, let alone result in increased net production sufficient to meet growing demand.

As reported by Bloomberg News on Nov. 12, 2007, EIA chief Guy Caruso stated:

> Crude-oil prices are being driven higher by ``market fundamentals,'' said Guy Caruso, head of the U.S. government's Energy Information Administration. Rising demand coupled with ``insufficient'' investment, lack of access to resource bases in the U.S. and elsewhere, and a ``dramatic rise in the cost of doing business'' are boosting prices, Caruso told reporters today at a briefing in Washington. ``We think we're in a different era with relatively higher real oil prices going out through 2030," he said.

And we can see from reviewing the latest EIA global oil balance tables that we have a serious problem. Oil demand has consistently exceeded oil supply over the five

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[7] Bloomberg News, available at: http://www.bloomberg.com/apps/news?pid=newsarchive&sid=ae43sOXpcl0A.
[8] Bloomberg News, available at: http://www.bloomberg.com/apps/news?pid=20602099&sid=aEbEeCepGSlY&refer=energy.
[9] The U.S. Army Corps of Engineers stated in a 2005 report: "We are at or near a peak in global oil production." Online at: http://stinet.dtic.mil/cgi-bin/GetTRDoc?AD=A440265&Location=U2&doc=GetTRDoc.pdf.

quarters.[10] According to these figures, there was an average global deficit of one million barrels per day for the first three quarters of 2007. This is not sustainable. According to IEA (the int'l equivalent of EIA), production ticked up in the 4th quarter of 2007 and in early 2008, but EIA doesn't apparently agree with those numbers yet.

A number of oil company CEOs have chimed in over the last year, with many agreeing that the world will be hard pressed to reach 100 million barrels per day, let alone exceed that level:

> During October 30-31, two oil company CEOs at the Oil & Money Conference (London) stepped out and made statements that set up a media breakthrough. The chairman of Libya's national oil company said, "There is a real problem that supply may not increase beyond a certain level, say around 100 million barrels [a day]." Total's CEO Christophe de Margerie was quoted by the Financial Times as saying, "One hundred million barrels a day is now in my view an optimistic case. That is not just my view; it is the industry view, or the view of those who like to speak clearly, honestly, and not…just try to please people." The previous week, James Mulva, CEO of ConocoPhillips, repeated a statement about a permanent ceiling on oil production that he first made last spring: "I don't think we are going to see the supply going over 100 million barrels a day." Former Saudi Aramco vice-president Sadad al Husseini stated that production "could be sustained for years but can't be significantly increased."

(Emphasis added). An even more substantial problem is the issue of "peak exports" – the notion that oil producing countries' domestic consumption is growing fast and, consequently, they are using more of the oil they produce. See attached a recent report from CIBC projecting a rapidly declining net export rate as key countries like Saudi Arabia, Iran and Russia use more of the oil they produce (*see* figure 2). CIBC's projections are already being proven overly optimistic as Mexico just announced that its exports declined by 12.5% in the first quarter of 2008 alone due to rapidly declining production from its major Cantarell oil field.[11] Also see a peer-reviewed report assessing Iran's likely export future, projecting exports literally falling to zero by 2013.[12]

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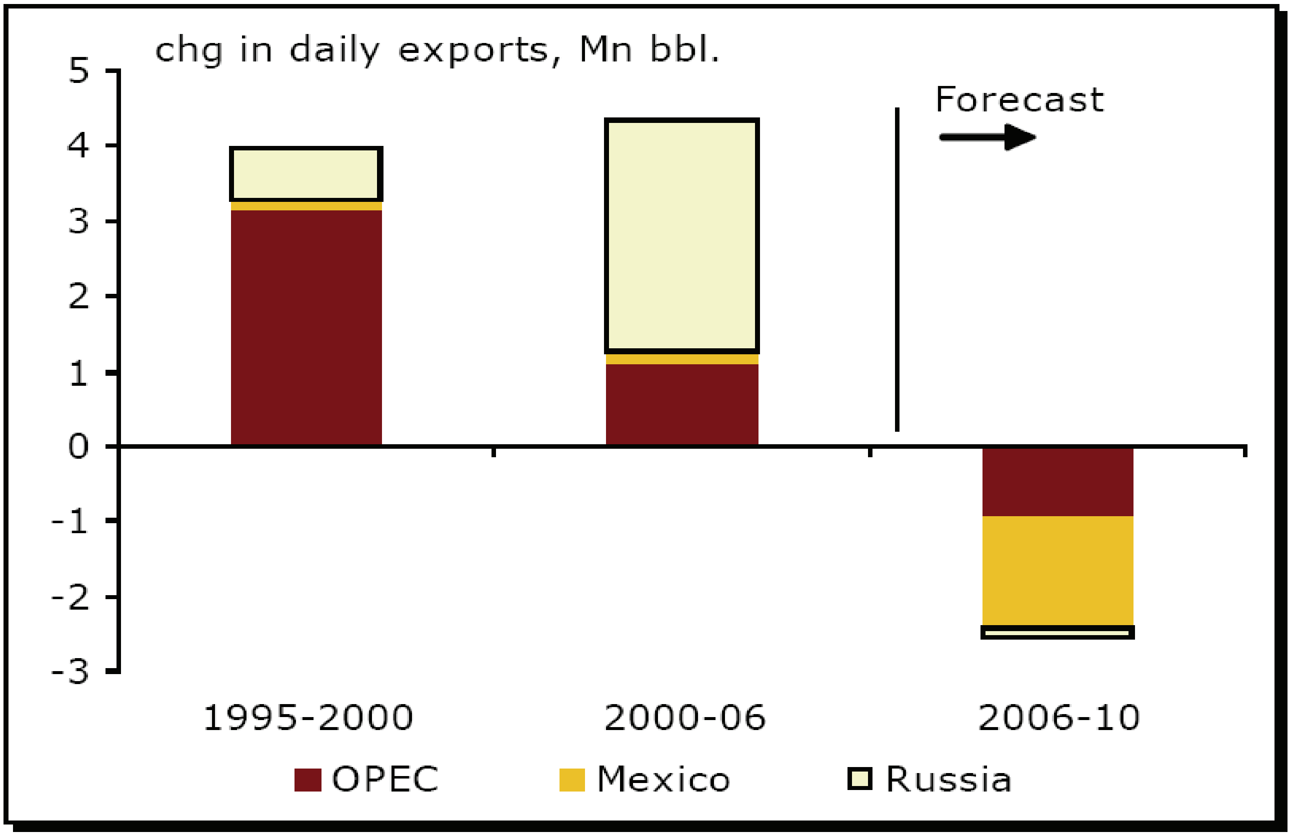
[10] EIA, online at: http://www.eia.doe.gov/emeu/ipsr/t21.xls.
[11] Online at: http://www.rigzone.com/NEWS/article.asp?a_id=60693.
[12] Online at: http://www.pnas.org/cgi/reprint/0603903104v1.

Figure 2. *Global net oil exports declines by 2010.*



Under the peak export analysis, even if global oil production does manage to increase, available oil for importers like the U.S. and California will shrink substantially. **This is a highly alarming scenario and should be considered immediately and comprehensively in the 2008 IEPR Update.**

Lifecycle emissions analysis

California is committed to doing its part to reduce greenhouse gas emissions resulting from its energy use and other behavior. As all climate scientists readily acknowledge, limiting only point source emissions of greenhouse gases (GHGs) may miss a large part of total emissions from any given activity. California law and policy recognizes this fact in the transportation sector, with AB 1007's passage in 2006 requiring a "full fuel cycle" (a term synonymous with "lifecycle assessment") assessment for all transportation fuels, including petroleum, ethanol and hydrogen. The Commission and the Air Resources Board completed the AB 1007 final report (State Alternative Fuels Plan, Dec. 24, 2007) late last year.[13]

[13] Online at: http://www.energy.ca.gov/ab1007/.

There is no such law or policy governing the utility sector, resulting in a serious imbalance in the state's energy and climate policy. The CPUC has authority to require a lifecycle emissions analysis in the utility sector. General information on lifecycle emissions analysis, as well as some specific analysis of certain technologies, may be found at Columbia University's Center for Lifecycle Analysis, at http://www.clca.columbia.edu/.

The Commission and ARB have expressed support for considering lifecycle emissions in crafting policies to mitigate climate change. The Commission stated, in the 2004 California greenhouse gas emissions inventory, published in December of 2006: "Because GHGs affect the entire planet, not just the location where they are emitted, policies developed to address climate change should include an evaluation of emissions from the entire fuel cycle whenever possible." (P. iii.) ARB is also on the record in numerous forums (including Deputy Director Mike Scheible's oral comments to the CPUC during the pre-hearing conference for Phase II of R.06-04-009) regarding its belief that lifecycle emissions analysis should be conducted when determining policies for mitigating climate change.

We have raised this issue in R.06-04-009 (the climate change proceeding) and the CPUC stated, on Feb. 2, 2007:

> In its PHC statement, Community Environmental Council recommended that the CPUC apply a lifecycle analysis to identify emissions related to liquefied natural gas storage facilities. Community Environmental Council argues that lifecycle analysis provides a more complete picture of emissions associated with energy consumption. However, such an analysis is considerably more complicated than traditional output-based emissions analysis. I understand from CPUC staff that researchers have yet to agree upon a methodology for performing lifecycle analyses of GHG emissions for some fuel sources, in particular, nuclear and liquefied natural gas. If this proceeding were to undertake a lifecycle analysis for liquefied natural gas facilities, to be consistent a lifecycle analysis would be necessary for all methods used to produce electricity. This would require well-established, peer-reviewed analyses and/or submission by the parties of alternative analyses for review in this proceeding. Because the methodology for lifecycle analysis of GHG emissions is still being developed, and widely accepted studies have not been completed, I do not include lifecycle analysis of GHG emissions in the scope of Phase 2. Because CARB has indicated a desire to conduct this type of analysis for its AB 32 regulations and those regulations are not required to be adopted until after the end of the timetable for this proceeding, it is possible that the CPUC may want to consider analysis of lifecycle emissions during a

later proceeding.[14]

The CPUC has not thus far, in R.06-04-009, indicated when it may re-consider the lifecycle emissions analysis issue. Accordingly, **we urge, more than a year after the CPUC's statement above, that the Commission in the 2008 Update examine the merits of lifecycle emissions analysis protocol for the electricity and the natural gas sectors**, similar to what has been completed for the transportation sector pursuant to AB 1007.

The Commission's support for LNG

The Commission has long expressed support for LNG as an alternative source of natural gas for California. However, price developments over the last year have made it clear that LNG will not – even if the Commission and all relevant state and federal agencies were unanimous in their support for new LNG import terminals – play a large role in supplying natural gas to California over the next few years, and possibly much longer, due to pricing problems alone. Prices in Europe and Asia for LNG have risen as high as $20/MMbtu, far higher than the $10-11/MMbtu that natural gas commands in the US (and this latter price is far higher than it has been over the last few years, but the differential still remains between U.S. prices and foreign prices).

Much has occurred in the LNG arena over the last few months. Due to the fact that recent news events are highly relevant to this proceeding, we include a lengthy quote from a recent (London) Sunday Times article on the natural gas and LNG situation in the United Kingdom:

> WHEN the Ramdane Abane set sail from the Algerian port of Arzew on February 5 with a £15m shipment of liquefied natural gas, the captain thought he was heading for Kent … where the cargo would be pumped into Britain's gas network. But she did not get far into her four-day voyage before being forced into a three-point turn.
>
> A message reached the bridge from Sonotrach, the Algerian gas producer that owned the cargo. Don't go to Britain, it said, go to Turkey instead. Iran had cut off Turkey's gas supplies and Turkey was now willing to pay twice the market rate. The customers in Britain would have to wait.
>
> The story is a familiar one. The Isle of Grain is Britain's only import terminal for LNG. Although the Kent plant is set up to receive at least one

[14] Pp. 13-14.

> shipment a week, the last ship that actually turned up docked on January 29.
>
> LNG shipments that had been expected to help smooth Britain's winter heating demand simply have not turned up. The gas has gone to higher bidders elsewhere. Japan has been paying over the odds for gas to keep its power plants running since an earthquake last year knocked out much of the country's nuclear power stations. Korea, China and Taiwan are also offering better prices.
>
> Only four years ago there was more than enough gas being pumped from the North Sea to meet our domestic demands, with the excess being piped to customers in continental Europe. In two years' time, roughly 40% of the UK's gas supplies will need to be sourced from overseas as North Sea stocks run dry.
>
> LNG imports from Qatar and Algeria are expected to account for roughly 11% of our supplies. By 2020, it is hoped that more than 30% of Britain's gas supplies will be sourced from LNG with tankers arriving from other producers such as Egypt, Nigeria, Trinidad and Oman.
>
> As Britain becomes more dependent on these supplies, the cost of keeping the lights on could well be dictated by events on the other side of the world.
>
> "Ten years ago, there was no way that a Japanese earthquake would have had any impact on gas prices in the UK," said David Cox, managing director of Pöyry Energy Consulting in Oxford, an adviser on energy affairs to the government. "But now, as the market shifts to being more global, that potential exists."[15]

The United Kingdom is quite similar to California in terms of population, size, and electricity portfolio composition. It is also similar in terms of having one LNG import terminal in operation and many others planned (California will soon have access to much of the LNG from Sempra's Costa Azul terminal just south of California, should such supplies become available in the very difficult market situation we find ourselves in today) and in terms of seeing its domestic natural gas production plummeting.

The Sunday Times article ends:

[15] "Price war threat to UK gas supplies," Sunday Times, March 9, 2008. Online at: http://business.timesonline.co.uk/tol/business/industry_sectors/natural_resources/article3510672.ece.

> In spite of all the money being ploughed into the UK's new LNG terminals, they are not guaranteed to receive gas. **The financing of these plants has been structured so that terminal owners get paid for each available unloading slot, irrespective of whether a tanker turns up or not**. The likes of BP and Centrica have signed 20-year deals ensuring that they have access to the Grain terminal whether they need it or not. …
>
> "The unfortunate truth for British consumers is that we are about to enter a period of much more expensive energy," said Mike Tholen, economics director of Oil & Gas UK. "That's going to feed back to everyone's gas and electricity bills."[16]

Additional relevant developments from the last few months:

- LNG shipments to Europe and Asia have commanded prices as high as $20/MMbtu[17];
- LNG shipments to Japan increased nine-fold since an earthquake permanently shut down Japan's 8 GW nuclear reactor in late 2007;
- Japan will face continuing LNG import problems, particularly after 2010, as Indonesia announced that it will halve LNG exports in order to have more gas to serve domestic demand[18];
- LNG shipments to the US in early 2008 fell to their lowest level in four years (an average of 800 MMcf/d, down from 2.1 Bcf/d in 2007);
- Chevron indefinitely delayed its Gorgon LNG liquefaction project in Australia due to extended permitting times and far higher capital costs than initially anticipated;
- Trinidad, the biggest supplier of LNG to the US, may, according to a recent study, literally run out of natural gas over the next twelve years due to overly aggressive pump rates[19];
- US domestic natural gas prices rose in 2008, to over $10/MMbtu in mid-March;
- FERC suspended review of the Sound Energy Solutions proposed LNG import project at the Port of Long Beach due to lack of site control by the applicant;
- Sempra's Costa Azul LNG import facility completion has been delayed for at least two months and total costs for the project will exceed $1 billion;

[16] Emphasis added.
[17] Bloomberg News, March 18, 2008. Online at: http://www.bloomberg.com/apps/news?pid=newsarchive&sid=aWwXBVpJMJWQ. Houston Chronicle, Feb. 21, 2008. Online at: http://www.chron.com/disp/story.mpl/headline/biz/5559258.html.
[18] Power & Materials, Feb. 12, 2008. Online at: http://www.kuna.net.kw/NewsAgenciesPublicSite/ArticleDetails.aspx?id=1883685&Language=en.
[19] Financial Times, "Breakneck gives some cause for concern," March 10, 2008. Online at: http://www.ft.com/cms/s/0/1b4b1ee8-ef0b-11dc-97ec-0000779fd2ac.html?nclick_check=1.

- Oregon's Governor Kulongoski sent a critical letter to FERC asking for a timeout in the federal permitting process for the three LNG import terminal proposals in Oregon, citing the lack of established need for LNG and the higher greenhouse gas emissions associated with LNG (when compared to domestic natural gas);

We append below the Environmental Council's recent comments to the CPUC in its LNG procurement proceeding (R.07-11-001), discussing in more detail the balanced access California enjoys to domestic natural gas supplies, the potential for renewable energy and energy efficiency to substitute for additional natural gas demand, the higher greenhouse gas emissions associated with the LNG lifecycle, and other issues.

In light of these many factors, we strongly urge the Commission to reexamine its policies on LNG.

Sincerely,

Tam Hunt
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Community Environmental Council

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Determine Issues Relating to the California Utilities' Procurement of Natural Gas Supplies from Liquefied Natural Gas Sources.	Rulemaking 07-11-001 (Filed November 1, 2007)

COMMUNITY ENVIRONMENTAL COUNCIL OPENING COMMENTS

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January 24, 2008

OPENING COMMENTS

The Community Environmental Council ("CE Council") submits these comments in accordance with the November 5, 2007, Order Instituting Rulemaking.

The CE Council is a non-profit environmental organization founded in Santa Barbara in 1970. Since 2005, promoting renewable energy and energy efficiency has been our primary mission. More information on our energy programs can be found at www.fossilfreeby33.org. Our state policy work is informed by our local and regional efforts on energy efficiency and renewable energy project development and outreach.

A summary of the CE Council's comments follows:

- The need for LNG imports to California has not been established and the EIA's Annual Energy Outlook 2008 supports the view that LNG imports to the West Coast are not needed and are unlikely to be economical (with the possible exception of the Costa Azul facility)
- Renewable energy and energy efficiency continue to erode natural gas consumption in California, which has declined slightly since its peak in 2000 and returned to levels seen about ten years ago, mirroring the declining trend seen in national natural gas consumption
- California has balanced access to five sources of natural gas: in-state supplies; Canada's West Sedimentary Basin; the Permian Basin; the San Juan Basin; the Rocky Mountains; and will soon have access to Sempra's Costa Azul LNG terminal, to be completed in early 2008
- There are also at least four new pipeline proposals to bring North American natural gas supplies to California, some using existing rights of way, providing ample opportunities for additional gas supplies from North American sources

- LNG has been consistently more expensive than North American natural gas over the last decade, suggesting that LNG is unlikely to act as a price moderator
- LNG has associated greenhouse gas emissions significantly higher than North American natural gas, due to production, liquefaction, transportation and re-gasification energy requirements; approving long-term LNG contracts without considering the higher associated emissions would be contrary to California's attempts to do its part to mitigate climate change
- Affiliate transactions for LNG present some risk for ratepayers due to the potential for market abuse

I. Discussion

The Commission's November, 2007, Order Instituting Rulemaking ("OIR") states: "The purpose of this OIR is to help ensure that there will be adequate supplies of natural gas at reasonable prices to meet California's long-term needs." As we demonstrate below, it is very likely that California will have adequate natural gas supplies at reasonable prices without any long-term LNG contracts being signed by the IOUs.

The OIR also states: "We will examine under what circumstances the large California utilities should enter into specific, long-term procurement contracts with LNG suppliers." Similarly, it is the CE Council's view that the IOUs should not at this time enter into any specific, long-term procurement contracts with LNG suppliers. This is the case because California currently enjoys balanced access to five sources of North American natural gas. These five sources of natural gas have historically been consistently cheaper than LNG imports to the U.S. and are likely to remain cheaper moving forward.

The CE Council believes that California will continue to have access to reasonably priced natural gas over the next decade or more without any reliance on LNG imports. This is the case due to the increased impact of energy efficiency and renewable energy in California and throughout the U.S. in reducing natural gas consumption and prices, as well as the dramatic capital cost and fuel cost increases in the global LNG market over the last few years, as well as the far higher natural gas prices in East Asia and Europe that will continue to attract the bulk of LNG imports.

A. **Demand for natural gas has declined slightly in California since 2001, due largely to increased energy efficiency and renewable energy; a need for additional LNG supplies has not been established.**

The OIR states:

> The Commission's current concerns about the adequacy of long-term natural gas supplies are heightened based upon the EIA's February, 2007 report entitled "Annual Energy Outlook 2007" (AEO2007) and the CEC's North American Natural Gas Review (NANGR), a report recently prepared by the CEC's staff and presented at the California Natural Gas Stakeholders Working Group Meeting at the CEC on September 6, 2007

(P. 6.) However, demand in California has declined slightly over the last seven years, returning to levels seen about ten years ago, and is likely to continue to remain level or drop over the next decade, according to the IOUs' own forecasts. This is the case largely due to the impact of increased energy efficiency and renewable energy. As the 2006 California Gas Report ("2006 CGR," produced by the utilities with the joint oversight of the Commission and the Energy Commission) states: "Gas demand for electric power generation is expected to be moderated by CPUC-mandated goals for renewable power generation and electric energy efficiency programs."[20] The 2006 CGR then shows the projected impact of energy efficiency and renewables on natural gas demand (Table 1).

Table 1. *Projected impacts of energy efficiency and renewable energy on natural gas demand in California.*[21]

Year	2006	2010	2015	2020	2025
California Energy Requirements by CPUC-Jurisdictional Utilities (1)					
Electricity Demand (GWh)	277,652	293,310	311,136	328,641	347,254
20% Renewables Goal for 2010					
Renewable Electric Generation (GWh/Yr) (2)	30,793	58,662	62,227	65,728	69,451
Increase over 2005 Level (GWh/Yr) (3)	6,967	34,836	38,401	41,902	45,625
Gas Savings over 2005 Level (Bcf/Yr)	44	218	240	262	285
Electric Energy Efficiency Goals (4)					
Electricity Savings over 2005 Level (GWh/Yr)	5,200	15,914	25,752	25,752	25,752
Gas Savings over 2005 Level (Bcf/Yr)	33	99	161	161	161
Energy Efficiency Goal for Natural Gas Programs (4)					
Gas Savings over 2005 Level (Bcf/Yr)	5	16	43	70	87
Total Gas Savings (Bcf/Yr) (5)	82	333	444	493	533

Similarly, the California Energy Commission's 2007 Final Natural Gas Market Assessment ("CEC Natural Gas Report") states that the slower rate of growth, 1.3% annually, for California natural gas demand (when compared to U.S. natural gas demand growth) is attributable to the following factors:

- Increased use of renewable energy
- Slower growth rate in electric generating capacity
- More fuel-efficient natural gas power plants
- Flat growth in the industrial sector

[20] 2006 California Gas Report, at 6. Online at: http://www.socalgas.com/regulatory/docs/2006_CGR.pdf.
[21] Id.

- Improved efficiency requirements for buildings and appliances standards
- Demand-side management programs[22]

In light of the impacts from energy efficiency and renewable energy, **the 2006 CGR projects natural gas consumption to decline slightly through 2015**, with an average 0.5% annual increase from 2006 through 2025 (Table 2). This is a stark contrast to the CEC Natural Gas Report's projection of 1.3% average annual natural gas demand growth through 2017 (up from 0.7% in the 2005 Integrated Energy Policy Report).

Table 2. *2006 CGR natural gas supply and demand projections for California (million cubic feet per day).*[23]

[22] "Final Natural Gas Market Assessment," CEC-200-2007-009-SF, Dec., 2007, p. 9-10.
[23] Id.

	2006	2007	2010	2015	2020	2025
California's Supply Sources						
Utility						
California Sources	442	442	441	441	442	441
Out-of-State	4,308	4,379	4,346	4,335	4,582	4,911
Net Withdrawal (Injection)	0	0	0	0	0	0
Utility Total	4,749	4,820	4,787	4,776	5,024	5,352
Non-Utility Served Load (1)	1,550	1,504	1,527	1,448	1,455	1,477
Statewide Supply Sources Total	**6,299**	**6,324**	**6,314**	**6,224**	**6,479**	**6,829**
California's Requirements						
Utility						
Residential	1,254	1,272	1,313	1,355	1,376	1,408
Commercial	505	510	519	510	492	490
Natural Gas Vehicles	26	26	33	39	46	54
Industrial	822	818	819	796	775	764
Electric Generation (2)	1,474	1,541	1,457	1,424	1,663	1,925
Enhanced Oil Recovery-Steaming	35	35	20	20	20	20
Wholesale/International+Exchange	420	403	413	418	431	464
Company Use and Unaccounted-for	89	90	89	89	94	101
Utility Total	4,624	4,695	4,662	4,651	4,898	5,227
Non-Utility						
EOR Steaming	695	677	653	625	598	575
EOR Cogen	212	212	212	211	220	231
Industry	49	45	40	27	31	32
Electric Generation	594	571	622	585	607	637
Non-Utility Served Load (1)	1,550	1,504	1,527	1,448	1,455	1,477
Statewide Requirements Total (3)	**6,173**	**6,199**	**6,189**	**6,099**	**6,353**	**6,703**

Notes:
(1) Consists of deliveries by Kern/Mojave pipelines to industrial, EOR cogen, EOR steaming and powerplant customers, and gas uses at Blythe, Elk Hills and Otay Mesa powerplants. Source: CEC 2005 IEPR.
(2) Includes utility generation and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of off-system deliveries.

The 2006 CGR has been fairly accurate thus far, with 2007 CGR data showing California natural gas consumption to be about 100,000 cubic feet per day <u>lower</u> in 2006 than projected in the 2006 CGR: 6,053 million cf/d actual consumption versus 6,173 million cf/d projected. (Full year consumption figures for 2007 are not yet available).

Given that the CEC's 2005 final natural gas forecast ("2005 CEC forecast") stated that California gas consumption would be 6.24 billion cf/d in 2006, on average, rising 0.7%

each year through 2016,[24] we can see that CEC's previous projections are already way off the mark, with actual consumption in 2006 187,000 cf/d lower than the CEC projected in 2005.

CEC seems to have recognized this over-estimate in its latest forecast, the 2007 CEC Natural Gas Report, which projects 2007 California consumption to be only 5,897 million cf/d on average.[25] This is a large discrepancy from the projections in the 2005 CEC forecast: 343,000 cf/d less than the projected 6.24 billion cf/d.

The 2006 CGR projects that total gas consumption will not, in fact, reach 6.24 billion cf/d until about 2017 – 11 years after the CEC stated, in 2005, that California had already achieved this level of consumption.

Accordingly, we can see that there is a history of over-estimates of natural gas demand by the CEC – similar to the history of over-estimates by the EIA, as discussed below. We see the same trend with the CGRs over the last six years, as discussed by our consultant in Attachment A.

Compounding the likely overestimates of natural gas demand in California and the Western U.S., the 2006 CGR and CEC Natural Gas Report do **not** consider the state's Energy Action Plan goal of 33% renewable electricity by 2020 or the impact of AB 32, the Global Warming Solutions Act (which was not in law when the 2006 CGR was written), which will not take effect until 2010 at the earliest. Nor do they consider energy efficiency goals beyond 2013, which was the temporal extent of the savings goals codified by the Commission in D.04-09-060. Nor do the CEC's projections take into

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[24] CEC Revised Reference Case in Support of Natural Gas Market Assessment, Sept. 2005, CEC-600-2005-026-REV, page 6.

[25] CEC Natural Gas Report, Appendix G. Interestingly, this report does not list California combined consumption in any single chart or anywhere in the body of the report. One has to add numbers from a number of different tables to derive this basic figure, which has always been easily accessible in previous CEC reports.

account the various renewable portfolio standards in place in most Western states, such as Arizona's (the second largest power market in the West) mandate for 15% renewable electricity by 2025.

As our consultant describes in Attachment A, meeting AB 32's requirements may lead to a 300 million cf/d reduction in natural gas consumption by 2020.

In light of AB 32's passage and continually rising fossil fuel prices, it is extremely unlikely that California will not enact further energy efficiency savings goals beyond 2013 – and the Commission is drafting such goals currently in R.06-04-010. The Commission also adopted in 2007 the goal of "zero net energy" for all new residential construction by 2020 and a similar goal for commercial buildings by 2030 (D.07-10-032). These goals will guide the IOUs and the Commission in designing and approving IOU energy efficiency programs – a process that is well underway with the drafting of the first energy efficiency Strategic Plan (as required by D.07-10-032) and the IOUs' 2009-2011 energy efficiency portfolios, which must incorporate the key recommendations of the Strategic Plan. The Energy Commission also adopted these goals in the 2007 Integrated Energy Policy Report. While these remain goals, it can be expected that the goals will grow some teeth over the next few years as concerns about climate change and fossil fuel prices increase. Moreover, "sweet teeth," exemplified by the incentives-led goals put in place by D.07-10-032, may in fact have more on-the-ground impact than traditional "command and control" measures.

In addition, it is very likely that the 33% by 2020 RPS, or an even higher mandate, will be codified into law in the next few years.[26] (At the same time, it is widely acknowledged, and the CE Council agrees, that the current 20% by 2010 RPS will

[26] A new proposition, the Solar and Clean Energy Act of 2008, may be on the ballot this fall and would, if approved by voters, codify a 40% by 2020 and 50% by 2025 RPS, going far beyond current law. There is a growing debate about the merits of this proposition, but it highlights the likelihood of a higher RPS being codified into law in the not-too-distant future.

probably not be met until 2012 or 2013, but this will probably lead only to a delay of a year or two in natural gas demand reductions, not a long-term trend.)

Further supporting the notion that future natural gas demand will likely be lower than forecast by the Energy Commission in its series of natural gas market assessments,[27] as well as the CGR forecasts, **the Energy Information Administration's 2008 Annual Energy Outlook (AEO) dramatically reduces projected national natural gas demand *vis a vis* the 2007 AEO**. AEO 2008 is the most recent major forecast of natural gas consumption by any entity and, accordingly, more fully reflects the high-price environment we have witnessed over the last few years as well as the rapid growth in renewable energy around the country (for example, 45% growth in wind power installed capacity in 2007 in the U.S.).

According to AEO 2008, national natural gas demand will be 3.3% (800 million cf/d) less by 2010 than in the 2007 reference case, 8.4% (2,200 million cf/d) less by 2020, and 10.3% (2,700 million cf/d) less by 2030. These changes to the AEO 2007 reference case occurred due to increased projections for renewable energy consumption, reduced economic growth projections (due to declining increases in productivity) and declining energy intensity (dropping an average of 1.6% per year).[28] See Figure 1.

Figure 1. *AEO 2008 natural gas national demand projections (trillion cubic feet)*.[29]

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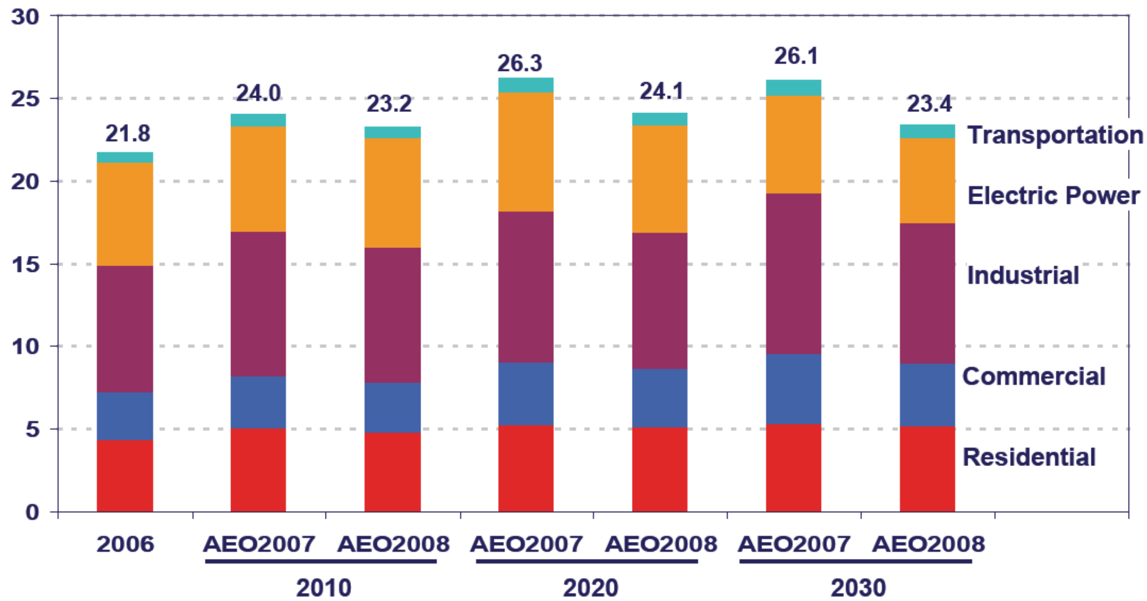
[27] The CE Council has been active in the Energy Commission's natural gas market assessment and Integrated Energy Policy Report proceedings over the last two years. A major theme of our work over the last year has been to urge the Energy Commission to explain why there is a significant discrepancy between the 2006 CGR and the Energy Commission's own natural gas demand projections. To date, our comments on this issue have not been addressed.

[28] AEO 2008 Overview, pp. 2-3, online at: http://www.eia.doe.gov/oiaf/aeo/pdf/earlyrelease.pdf.

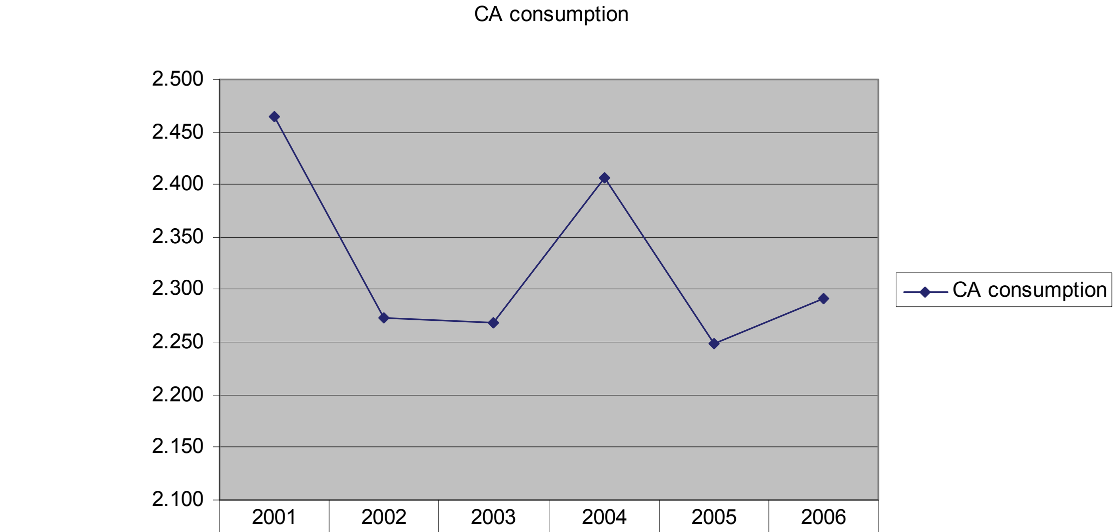
[29] Id.



The actual history of natural gas consumption in California and the U.S., over the last ten or more years, supports the AEO 2008 natural gas consumption forecast reductions. California consumption peaked in 2000 and has declined considerably since then, returning to levels seen about ten years ago (Figure 2). U.S. natural gas consumption is similar, peaking in 2000 and in 2006 returning to levels not seen since 1994 (Figure 3).[30]

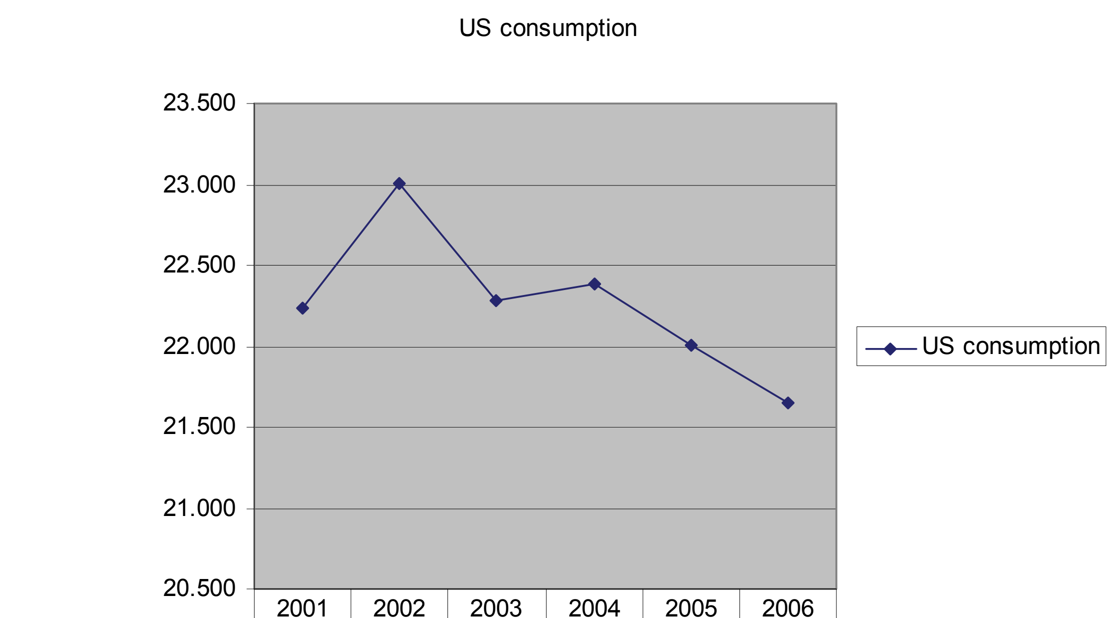
Figure 2. *California total natural gas consumption 2001-2006 (trillions of cubic feet)*.[31]

[30] EIA, online at: http://tonto.eia.doe.gov/dnav/ng/hist/n9140us2a.htm.
[31] EIA, online at: http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SCA_a.htm.



	2001	2002	2003	2004	2005	2006
CA consumption	2.465	2.273	2.269	2.407	2.248	2.292

Figure 3. *U.S. total natural gas consumption 2001-2006 (trillions of cubic feet).*[32]



	2001	2002	2003	2004	2005	2006
US consumption	22.238	23.007	22.276	22.389	22.010	21.653

[32] Id., online at: http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

The supply picture for North America is also quite different from previous projections. AEO 2008 states:

> Onshore production of unconventional natural gas in *AEO2008* is expected to be a major contributor to growth in U.S. supply, increasing from 8.5 trillion cubic feet in 2006 to 9.5 trillion cubic feet in 2030. As in *AEO2007*, most of the increase in unconventional production is projected to come from gas shale, which more than doubles over the projection, from 1.0 trillion cubic feet in 2006 to 2.3 trillion cubic feet in 2030.[33]

Due to declining demand and increasing domestic production, AEO 2008 also dramatically reduces projected LNG import amounts. Forecasted imports rise to three trillion cubic feet per year (8.2 billion cf/d) by 2017, up from approximately 780 billion cubic feet per year (2.14 billion cf/d) in 2007, and remain essentially level through 2030 (the last year of the forecast).[34] This is a dramatic reduction of projected LNG imports: reduced 50% by 2030 from the AEO 2007 projection (Figure 4).

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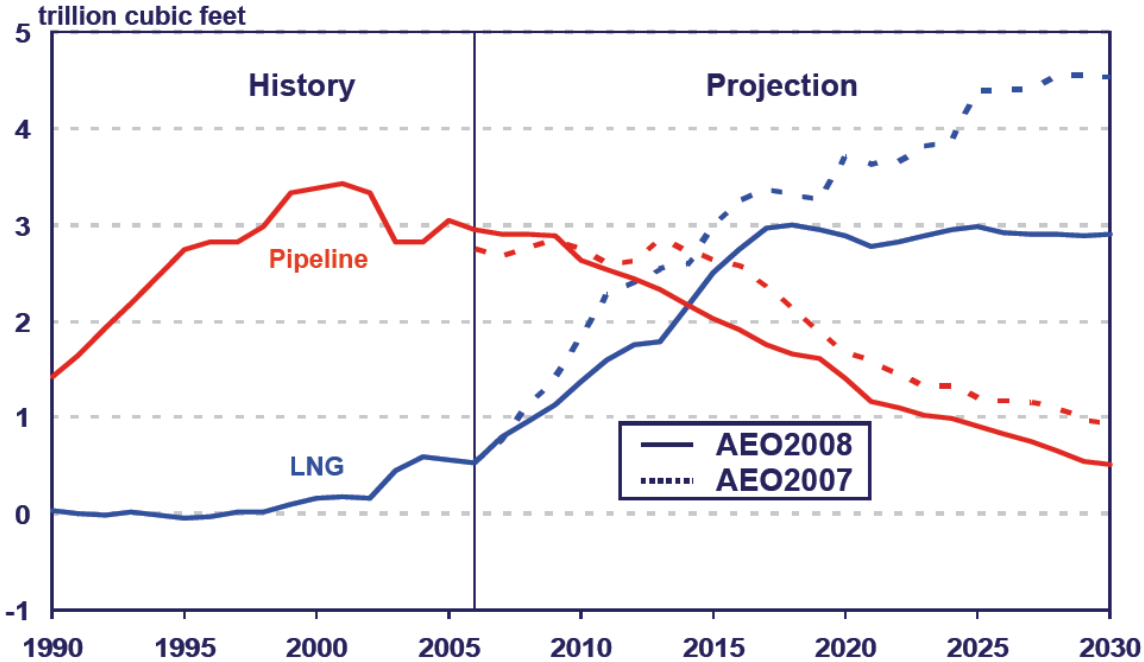
[33] Id.

[34] Id.

Figure 4. *AEO 2007 and 2008 forecasts for LNG imports.*[35]



The OIR (p. 6) cites the September 2007 presentation by Energy Commission staff on North American natural gas demand as one reason for its concern over adequate natural gas supplies. However, **the Energy Commission presentation cited in the OIR significantly overstated current LNG imports to the U.S.,** stating at page 16 of the presentation that the U.S. imported four billion cubic feet per day of LNG in 2007. In fact, the U.S. imported half that amount: 2.14 billion cf/d in 2007.[36] The EIA's latest Short-Term Energy Outlook ("STEO") projects that LNG imports will total about 2.57 billion cf/d in 2008 and 3.23 billion cf/d in 2009.[37]

The EIA explains the lower imports figures in its STEO: "The latest decline in LNG imports to the United States has been caused by the combination of increased demand

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[35] EIA, 2008 AEO presentation by Guy Caruso, December 12, 2007.
[36] EIA, Short-Term Energy Outlook, January, 2008, p. 5. Online at: http://www.eia.doe.gov/emeu/steo/pub/jan08.pdf.
[37] Id. EIA uses total year import figures, so it is necessary to divide EIA's figures by 365 to derive the cf/d figure that CEC and the CGR use.

and higher natural gas prices in other markets around the world, including Asia and Europe."[38] It is unlikely that these global trends will change any time soon, due to continued rapid economic growth in China, India, Europe, etc., greater concern over climate change around the globe that favor natural gas and other power sources over coal, and major events like the Japanese earthquake that destroyed the 8 GW Kashiwazaki-Kariwa nuclear plant, the world's largest (leading to LNG imports as the primary means of making up for this lost power).

The AEO 2008 Overview explains the dramatic change in the prior year's projected LNG imports:

> The lower projection is attributable to two factors: higher costs throughout the LNG industry, especially in the area of liquefaction, and decreased U.S. natural gas consumption due to higher natural gas prices, slower economic growth, and expected greater competition for supplies within the global LNG market.[39]

The AEO 2008 Overview also states that U.S. LNG import terminal capacity utilization is expected to be quite low through the next decade:

> Given global LNG supply constraints, overall capacity utilization at the U.S. LNG import facilities is expected to remain under 35 percent through 2013, after which it is expected to increase to 57 percent in 2017 and remain in the range of 55 to 58 percent through 2030.[40]

Last, the EIA natural gas demand forecasts are probably overly conservative, as demonstrated by the trend over the last eight years in AEO projections. Figure 5 shows the natural gas projections over the last eight years, demonstrating a consistently rising price projection as actual prices steadily rose.

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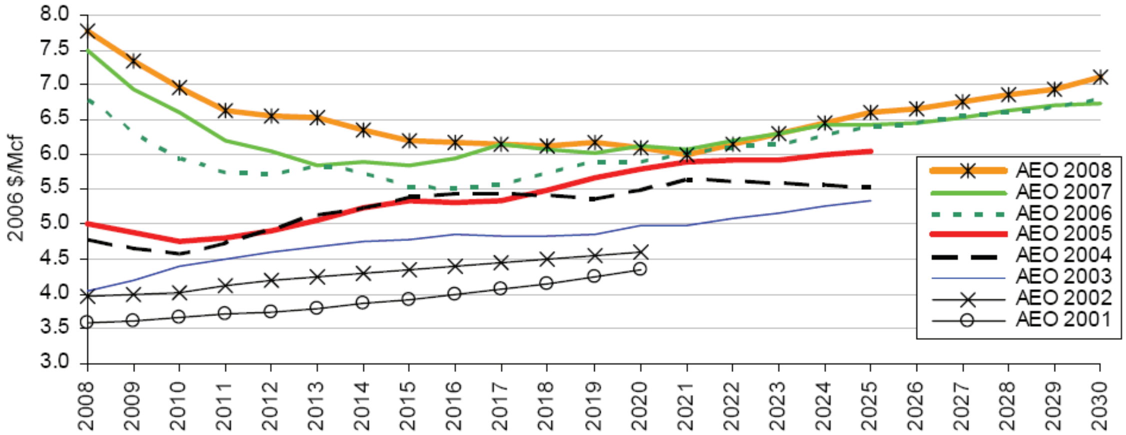
[38] Id.
[39] AEO 2008 Overview, p. 9.
[40] Id.

Figure 5. *EIA AEO natural gas price projections, in 2006 dollars, from 2001 to 2008.*[41]



These forecasts demonstrate that EIA forecasting tends to be overly conservative – and we may, given current trends for natural gas, LNG, and other electricity generation options, expect that actual prices will very likely be higher than EIA currently projects – thus reducing natural gas demand growth even further.

B. California enjoys balanced access to six sources of natural gas

California will soon enjoy balanced access to six sources of natural gas: California gas; Canadian West Sedimentary Basin gas; Permian Basin gas; San Juan Basin gas; Rocky Mountain gas; and Sempra's Costa Azul (Baja California) LNG.

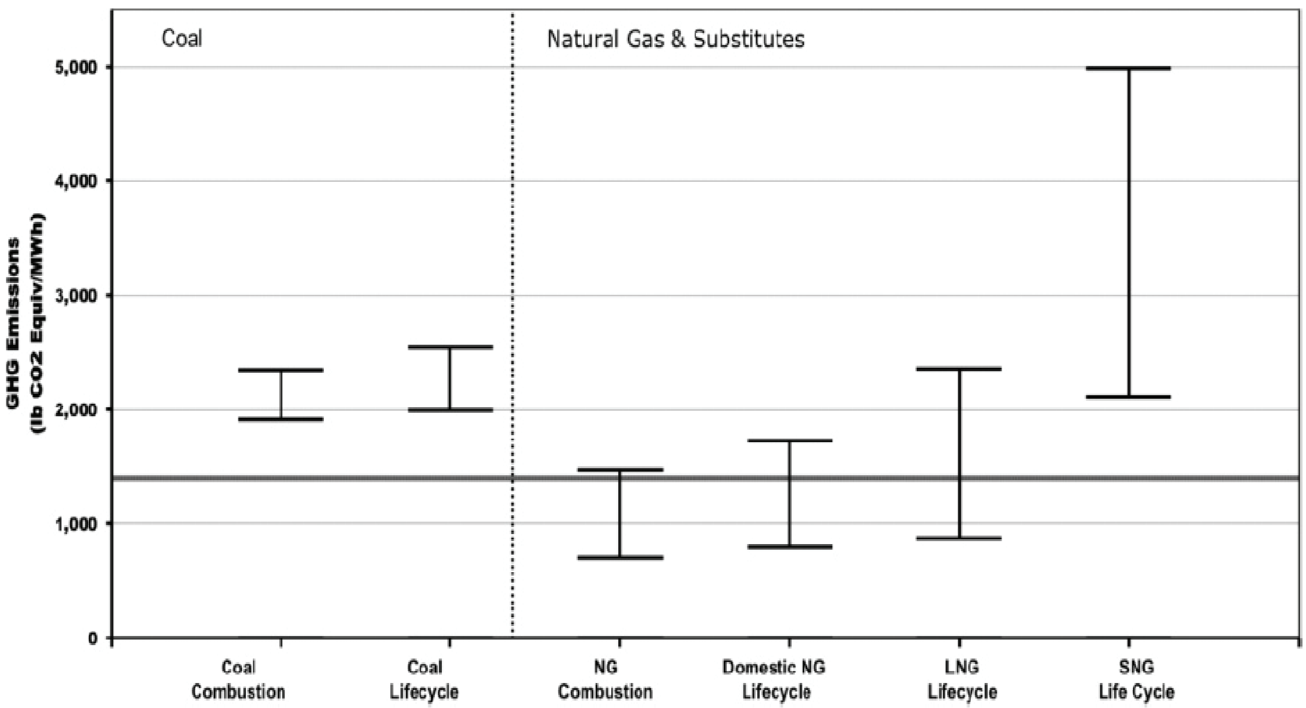
See Attachment A for comments by CE Council's consultant, Crossborder Energy, on California's access to these sources of natural gas. Crossborder Energy concludes that due to the balanced access to natural gas, California will not need any additional LNG supplies over the next decade and probably for an even longer period.

C. LNG can lead to far higher greenhouse gas emissions than domestic natural gas, so allowing IOU LNG contracts would contravene the intent of AB 32

[41] Bolinger, Mark, and Wiser, Ryan, "Comparison of AEO 2008 Natural Gas Price Forecast with NYMEX Futures Prices," (Jan., 2008), online at: http://eetd.lbl.gov/ea/emp/reports/53587_memo.pdf.

Contrary to popular wisdom, **not all natural gas is created equal**. LNG has associated emissions that result in it being a potentially far higher source of GHG emissions and criteria emissions than domestically produced natural gas – up to twice as high, depending on the amount of energy used to produce, liquefy, transport and re-gasify the natural gas.[42]

Figure _. *Lifecycle emissions of domestic natural gas, LNG, coal and syngas.*[43]



The state, through the work of ARB and the CEC, is committed to considering the feedstocks for biofuels, such as corn for ethanol, in determining which alternative transportation fuels to pursue (through the state Alternative Fuels Action Plan, pursuant to AB 1007). It makes no sense to avoid the same questions in the electricity

[42] Jaramillo, P., Griffin, M., et al., "Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation," Environmental Science & Technology, published online July 25, 2007. Abstract available at http://pubs.acs.org/cgi-bin/abstract.cgi/esthag/asap/abs/es063031o.html.
[43] Id.

sector. Attempting to mitigate climate change without considering lifecycle emissions could lead to highly counter-productive results.

If the Commission decides to permit LNG long-term supply contracts for the IOUs, it should first consider the increased GHG emissions associated with imported LNG. When considering the wisdom of such contracts, the Commission could create an additional "adder," on top of the existing adder used in the procurement proceeding when considering new fossil fuel electricity contracts. This adder is currently \$12.50/ton of CO_2, but should be modified to apply to all power and natural gas contracts to reflect the lifecycle emissions of each product. **A sliding scale adder would best reflect the sliding scale of GHG emissions associated with each product**.

Calculating the associated emissions need not be an overly burdensome process for the Commission or regulated entities. Instead, the Commission may draw upon established scholarship by the CEC and others (pursuant to the AB 1007 process, for example) to establish emissions factors for domestic natural gas versus LNG and any other relevant categories and apply these factors to each proposed contract.

The Commission's sister agencies, ARB and CEC have expressed support for considering lifecycle emissions in the utility sector as well as the transportation sector (which is covered by the statutory mandate of AB 1007). The CEC stated, in the 2004 California greenhouse gas emissions inventory, published in December of 2006: "**Because GHGs affect the entire planet, not just the location where they are emitted, policies developed to address climate change should include an evaluation of emissions from the entire fuel cycle whenever possible**." (P. iii.)

ARB is also on the record in numerous forums (including Deputy Director Mike Scheible's oral comments to the Commission during the pre-hearing conference for

Phase II of R.06-04-009, the climate change proceeding) regarding its belief that lifecycle emissions analysis should be conducted when determining policies for mitigating climate change. **Accordingly, the Commission is alone in thus far declining to utilize lifecycle emissions analysis.**

D. LNG has been consistently more expensive than domestic natural gas over the last ten years and will probably remain so

The OIR asks: "Can we determine in this OIR that long-term procurement contracts between utilities and LNG suppliers have the potential to be economically beneficial to the utilities' ratepayers relative to long-term contracts for other supplies of natural gas or spot market purchases of LNG?" (Pp 9-10.)

The CE Council believes that this question can be answered in this proceeding and that it is unlikely at this time that long-term LNG contracts will be beneficial for ratepayers. This is the case because LNG has historically been more expensive than domestic natural gas and because ratepayers have an interest in low-carbon sources of energy (and LNG is generally not such a source, as discussed above).

The OIR acknowledges the high price of LNG in its statement, at page 10: "Since current LNG prices substantially exceed those of domestic natural gas at present, would it be more appropriate to consider long-term procurement at some later time?" **The CE Council believes it would be more appropriate to consider long-term procurement at a later time, for reasons discussed below**.

The price of LNG in the United States has almost always been higher than domestic natural gas – and sometimes significantly higher. Figures 6 and 7 show the price history of domestic natural gas and LNG in the U.S. over the last decade.

Fig. 6. *Cost comparison of wellhead domestic natural gas price vs. LNG import price, in $/thousand cubic feet, from 1995-2005.*[44]

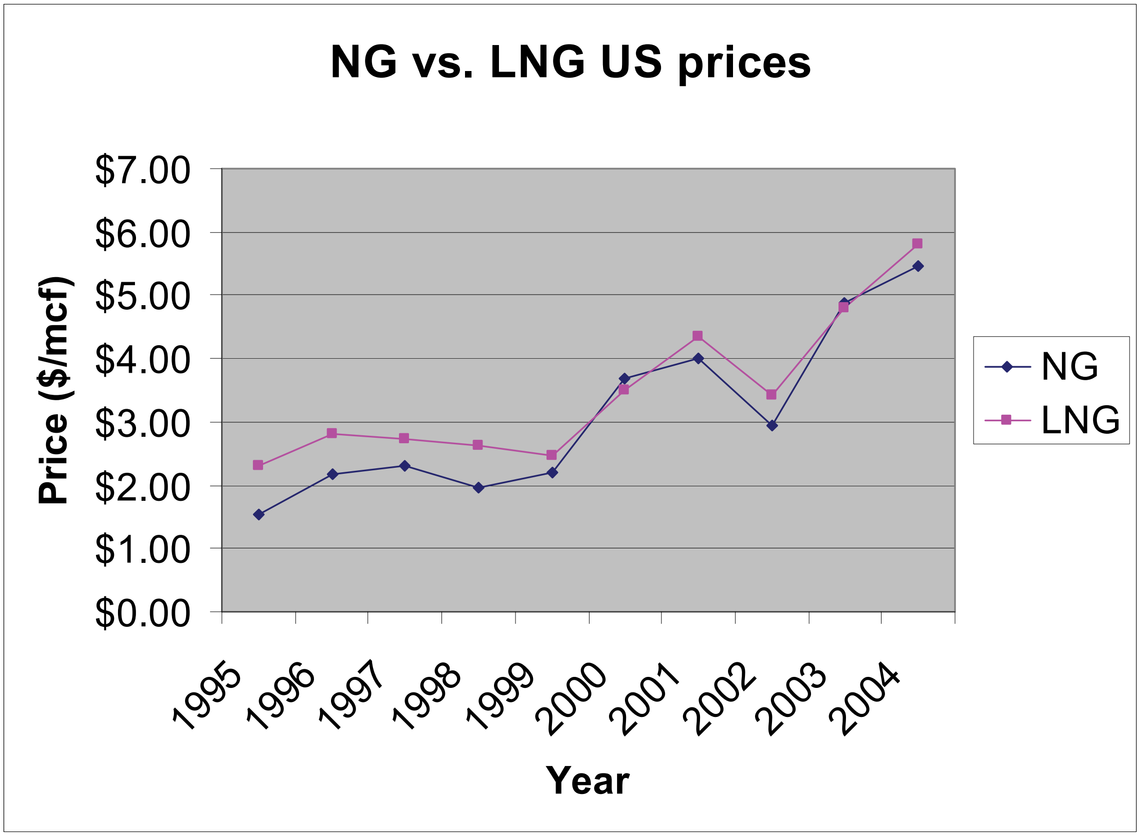
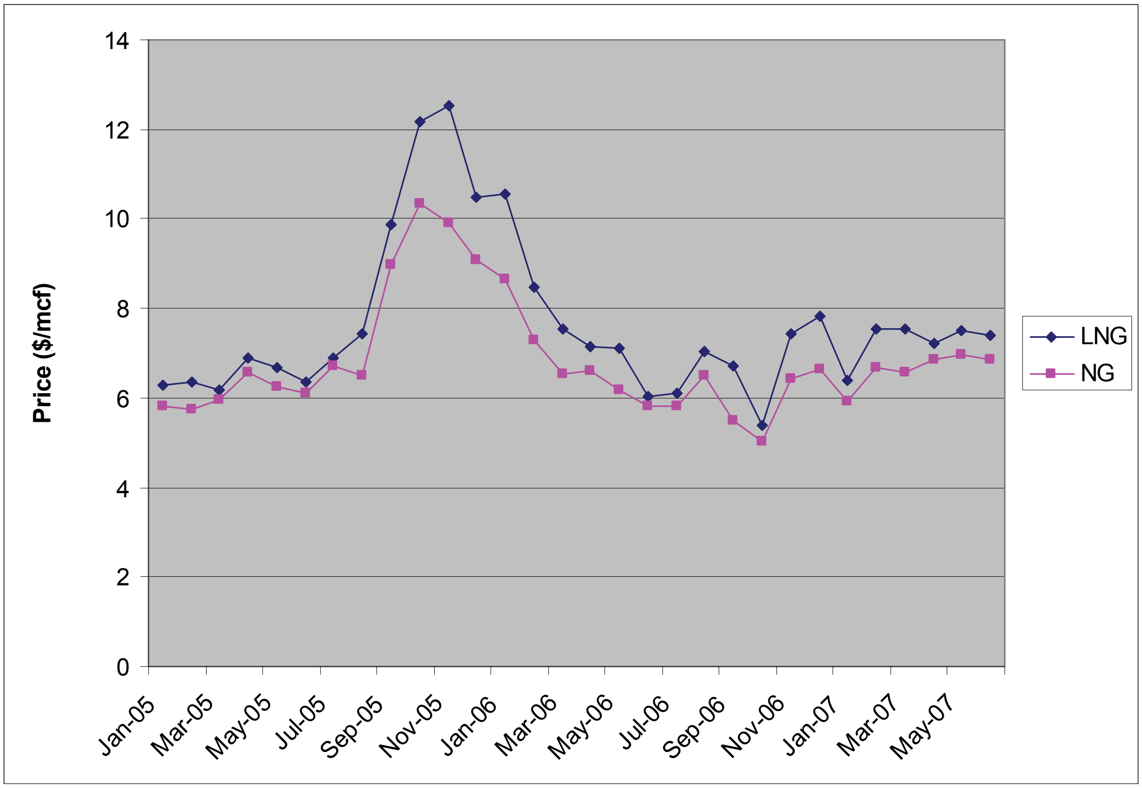


Fig. 7. *Cost comparison of domestic natural gas wellhead price versus LNG imports, in $/thousand cubic feet, 2005-2007.*[45]

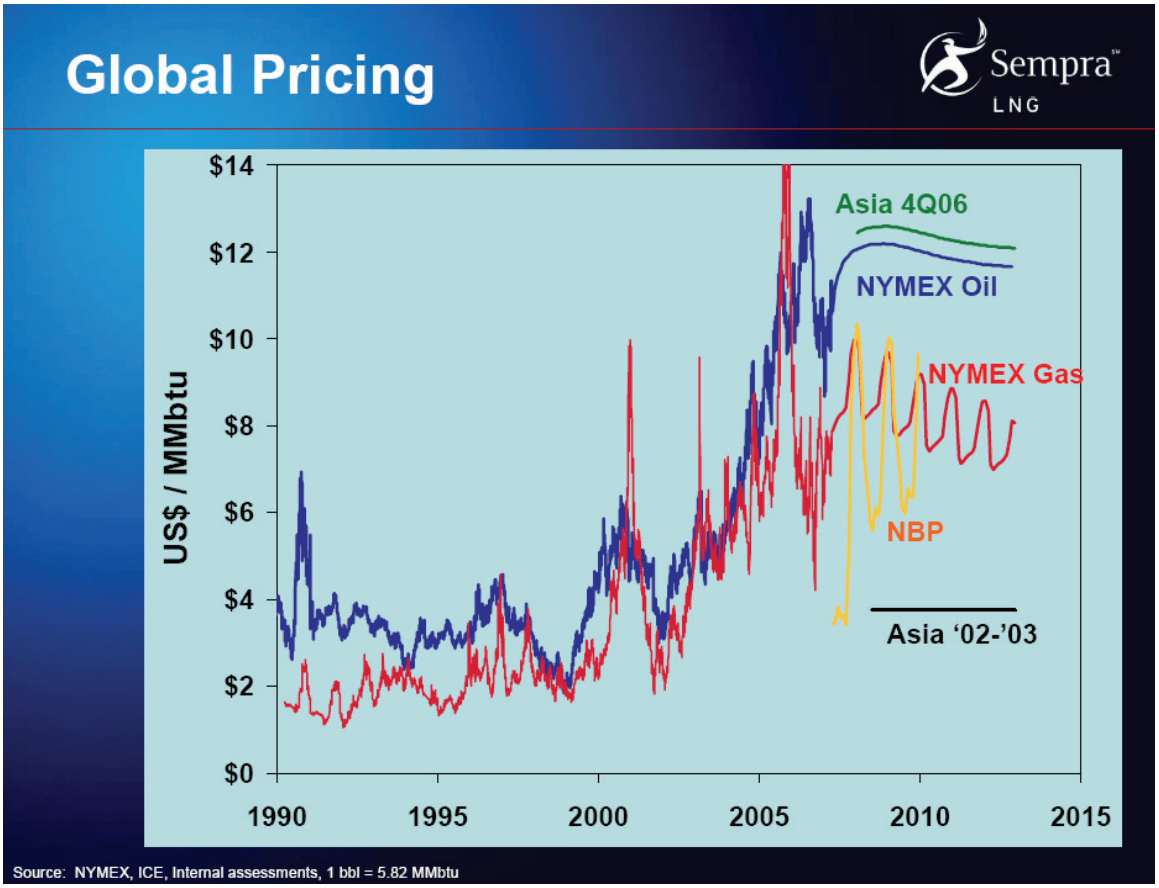
[44] Energy Information Administration, online at: http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3m.htm and http://tonto.eia.doe.gov/dnav/ng/hist/n9103us3m.htm.

[45] Id.



We note, also, that the *Continental Forge* settlement between Sempra Energy and various plaintiffs requires Sempra to offer LNG to its subsidiaries in Southern California at the California Border Price Index less two cents per MMbtu. Such a requirement is a tacit admission that LNG is likely to be more expensive than domestic natural gas, or why would such a requirement be included in the settlement? Supporting this point is information from a May, 2007, Sempra presentation on the likely cost of LNG in the global market, showing that Asian LNG import prices are projected to be above $12/MMbtu from 2009-2014, whereas US NYMEX gas prices are expected to be substantially less (Figure 8, see "Asia 4Q06" for Asian pricing). Since Sempra's presentation, prices have risen even higher, further exacerbating the price differential. Accordingly, it is highly unlikely that Pacific Rim LNG will make it to the Costa Azul terminal unless Asian LNG import prices decline significantly or US natural gas prices increase significantly.

Figure 8. *Sempra presentation on likely cost of LNG on global markets (May, 2007).*



It is for these reasons that the CE Council believes no special process is required for LNG long-term contracts. Rather, the utilities should continue to procure natural gas from North American suppliers, from any of the four sources discussed in Attachment A. Alternatively, if the Commission decides the utilities should be allowed to enter into long-term LNG contracts, the utilities should seek to procure natural gas, from LNG importers or North American sources of natural gas, under essentially the same process as exists today (as described in section 3.2.2. of the OIR) – with the sliding scale greenhouse gas adder discussed above, as a means of internalizing the higher GHG emissions associated with LNG.

Last, it is important to keep in mind that California natural gas prices are currently among the lowest in the country, as are rates in other Western states like Oregon, Idaho and Arizona. This is the case because of the balanced access to multiple natural gas basins that California and the West enjoys, as discussed in detail in Attachment A.

E. Affiliate LNG transactions present some potential problems

The CE Council will comment on this issue in detail in reply comments. We will at this point express only our concern about the potential for abuse posed by affiliate transactions, particularly in the case of Sempra's Costa Azul LNG terminal and SoCalGas and SDG&E, should Pacific Rim LNG market prices support such transactions.

II. Conclusion

The Commission should not approve any long-term LNG contracts at this time due to the lack of any proven need for LNG, the higher greenhouse gas emissions of LNG, the higher costs of LNG versus domestic natural gas, and the potential for ratepayer abuse through affiliate transactions.

Due to the Commission's concern about natural gas supplies, it is our view that rather than focusing on LNG as a "fix" for potential supply problems, it would be far better policy to, instead, continue on the path that the Commission, Energy Commission, Governor Schwarzenegger, Legislature, and many other entities have made such a high priority: increasing energy efficiency and renewable energy. Increasing energy efficiency and renewable energy will provide a truly long-term and sustainable solution to our growing energy problems. By focusing on LNG as a solution for possible domestic natural gas supply shortfalls, the Commission risks creating yet another foreign fossil fuel dependency, exacerbating climate change, and exposing California ratepayers to higher prices.

Respectfully submitted,

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