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COMMUNITIES FOR A
BETTER
ENVIRONMENT

December 9, 2008

Mary Nichols, Chairman
James Goldstene, Executive Officer
California Air Resources Board
1001 "I" Street
P.O. Box 2815
Sacramento, CA 95812

Re: **Supplemental comment on AB32 Scoping Plan;**
Increasing GHG emissions from dirty crude

Dear Chairman Nichols and Mr. Goldstene,

California oil refineries are switching to more contaminated crude oil. The attached analysis documents some critically important points:

- Refinery CO_2 equivalent emissions from hydrogen steam reforming already increased substantially, by approximately three million metric tonnes per year, since 1995.
- The primary cause of this pollution is a shift to more contaminated crude oil inputs. Low sulfur fuel standards are not the primary cause of this pollution.
- By 2020 accelerating use of lower quality oil threatens to increase CO_2eq emissions by another eight million to thirteen million tonnes per year from steam reforming alone.
- Analysis of statewide refining is consistent with and supports previous findings that a switch to inherently dirtier feedstock for transportation fuel production could worsen toxic pollution near refineries and may overwhelm climate protection efforts.

This evidence further supports CBE's comments on the Scoping Plan. Please note that it also supports the advice given to your agency in the LCFS-1 report, that pollution trading across sectors is unlikely to be effective.

Respectfully submitted,

Greg Karras
Senior Scientist

Enclosures: Karras, May and Lee, 2008. Increasing GHG emissions from dirty crude.
Robinson and Dolbear, 2007.
Brandt and Farrel, in press.

Copy: Interested organizations and individuals

Increasing GHG emissions from dirty crude

Analysis of publicly available data for one of the oil refining processes expanding for more contaminated oil in California: Hydrogen steam reforming.

Communities for a Better Environment (CBE)
Research & analysis: Greg Karras, Senior Scientist
Technical review: Julia May, Senior Scientist
Anna Yun Lee, Staff Scientist

December 8, 2008.

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The mission of **Communities for a Better Environment** (CBE) is to achieve environmental health and justice by building grassroots power in and with communities of color and working class communities. Founded in 1978, CBE combines in-house scientific, legal and organizing expertise to leverage plant-specific pollution prevention and regional policy progress that could not be achieved using science, organizing or legal advocacy alone. Thousands of CBE members and supporters live in the greater Los Angeles and San Francisco Bay Areas.

Increasing GHG emissions from dirty crude

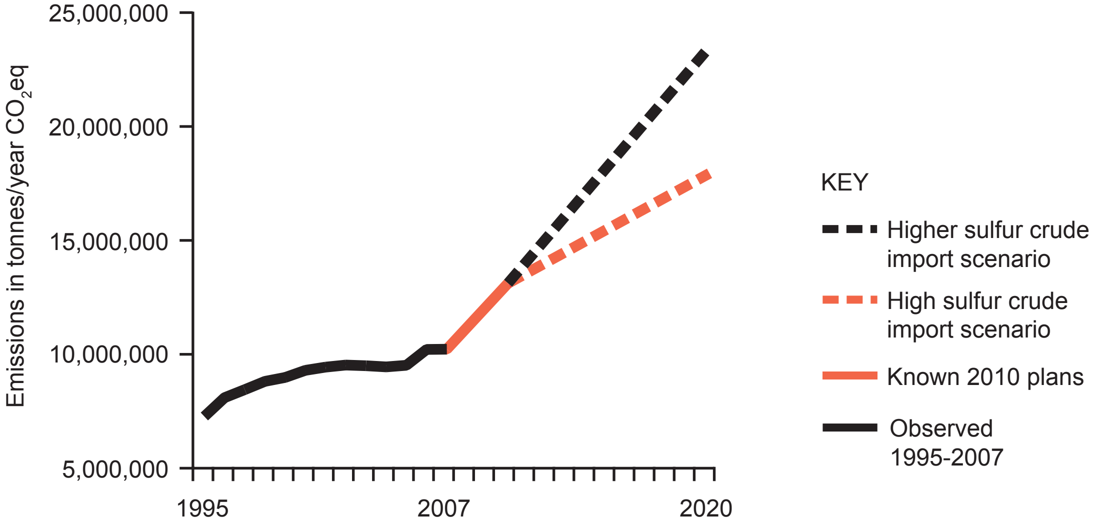
Introduction

As government officials debate long-term plans for climate protection the next generation of oil refining infrastructure is being built. Communities near refineries are grappling with the toxic threats posed by these plans. This analysis of publicly available data focuses on California oil refineries, greenhouse gases (GHGs) and one refining process: hydrogen steam reforming.

Findings and recommendations

Steam reforming for the extra hydrogen needed to refine more contaminated oil in California has already increased greenhouse gas emissions substantially, by approximately three million metric tonnes per year since 1995 (CO_2eq). Plans to feed much more hydrogen to even dirtier oil refining could further **increase statewide GHG emissions by another eight million to thirteen million tonnes per year** between 2008 and 2020, from steam reforming alone. See Figure 1.

Figure 1. Increasing greenhouse gas emissions from hydrogen steam reforming by California oil refineries, 1995-2020



Source: Analysis of data in Figure 2 (1995-2007) and Table 7 (2008-2020).

Emissions are increasing as steam reforming production increases to feed more hydrogen to the expanding hydroprocessing of more contaminated refinery crude oil inputs. Crude inputs to California refineries are getting dirtier as refiners shift to imports that include some of the higher-sulfur oils produced worldwide. This shift is accelerating as domestic supply dwindles.

Plans for GHG emission reductions that are needed by 2020 and 2050 in order to avoid severe global warming should address refinery feedstock quality. Steam reforming is only one of many types of oil infrastructure that is expanding for lower quality oil, and emitting more GHGs. A full-blown switch to dirtier oil threatens to overwhelm and thwart climate protection efforts.

We should treat refinery feedstock like we treat power plant feedstock. California is phasing out coal as a source of electricity served by its public utilities. We must now limit, and then phase out, dirtier oil refinery feedstock as well.

Increasing GHG emissions from dirty crude

Emission source

Oil refining is the world's second largest user of hydrogen. Steam reforming is the U.S. refining industry's technology of choice for add-on hydrogen plants. Steam reforming produces hydrogen from light hydrocarbons such as methane and superheated steam, in contact with a catalyst. The process reactions proceed at extremely high temperature, about 1,500 ºF, which is achieved by burning fossil fuel. *(1)* Burning this fossil fuel emits GHGs, among other pollutants.

It takes approximately 459 British thermal units (Btu) of heat to make one cubic foot of hydrogen by steam reforming. *(1)* Burning natural gas emits approximately 53.1 kilograms of GHG per million Btu. *(2)* Thus, steam reforming emits approximately 24.37 tonnes of GHG for each million cubic feet of hydrogen produced–if it burns natural gas, the least dirty fuel refineries burn, and the fuel assumed in this analysis. These emissions are expressed as CO_2 equivalent (CO_2eq) accounting for the potency of carbon dioxide, methane and nitrous oxide emissions.

Observations from 1995-2007

Emissions from steam reforming increased from 1995-2007. See Figure 2. In 2007 California refiners' steam reformers produced approximately 1,151 million cubic feet of hydrogen per day, an increase of 329 million cf/d over their 1995 production. *(3)* At 24.37 tonnes/million cf, this indicates a GHG emissions increase of 2.93 million tonnes/year. This estimate is for steam reforming alone, and includes steam reforming by all refineries in California that produce California on-road gasoline and/or diesel.

Steam reforming increased with hydroprocessing. California refiners added 240,000 barrels/day of hydrocracking since 1995, and now have capacity to hydrocrack more than twice as much of their crude input as the average US refinery. *(3)*

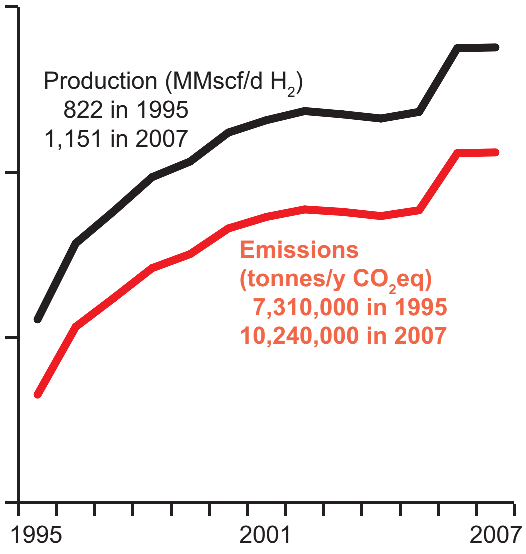
Table 1. Typical hydrogen steam reforming inputs and GHG emission factors.

Process feeds:	Methane or naphtha Water (for steam)
Energy input:	459 Btu/scf (heat per standard cubic foot of hydrogen produced)
Emissions:	53.1 kg/MMBtu* 24.37 tonnes/MMscf hydrogen*

* Carbon dioxide equivalents of CO_2, CH_4 and N_2O emissions from natural gas fuel.

From USDOE (Ref. 1) and CARB Compendium of Emission Factors (Ref. 2; natural gas default factor).

Figure 2. Steam reforming production and emissions, California refineries, 1995-2007



Data from Oil & Gas Journal Worldwide Refining surveys (Ref. 3) and CARB (Ref. 2 and Table 1). Based on 90% of available production capacity.

California refiners also added 272,000 b/d of hydrotreating since 1995, and 84,100 b/d of that was hydrotreating of heavy oil streams such as gas oils. *(3)* Using this increased hydroprocessing capacity required more hydrogen.

Typical hydrogen demands for hydroprocessing various oil streams are shown in Table 2. Processing heavier streams such as gas oil requires several times more hydrogen per barrel than processing lighter streams such as naphtha (gasoline-sized hydrocarbons). Total hydrogen demand in California refineries, as estimated from these hydrogen requirements and the annual production capacities reported for these processes, is shown in Figure 3.

California refiners' hydroprocessing increased their hydrogen use by approximately 387 million cf/d since 1995. No such increase occurred, however, in catalytic naphtha reforming, which creates hydrogen as a byproduct. Cat-naphtha reforming declined by 7% since 1995 *(3)* and is not likely to increase because it creates volatile toxic chemicals limited by fuel standards.

The net result of increased hydrogen demand from more hydroprocessing while hydrogen byproduction from cat-naphtha reforming did not increase drove an increase in steam reforming to supply that extra hydrogen. See Figure 3.

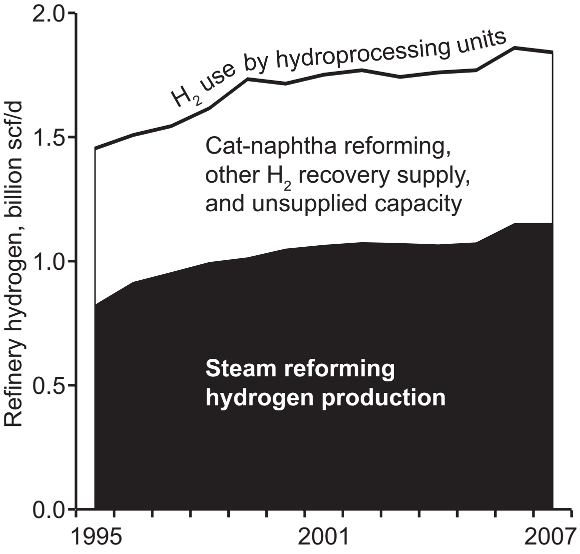
Refining more contaminated crude causes increased hydrogen demand in at least three related ways. First, hydrogen is bonded to contaminants to remove them from the oil (this avoids poisoning process catalysts and violating vehicle fuel standards); so removing more contaminants from dirtier oil takes more hydrogen. Second, sulfur and other catalyst poisons concentrate in the denser and heavier components of crude such as gas oil and residua; so refining dirtier crude requires more of the types of hydroprocessing that require the most hydrogen.

Table 2. Typical hydrogen requirements for hydroprocessing different feeds.[a,b]

Process	Feed	Hydrogen per barrel of feed
Hydrotreating	naphtha[c]	350 scf/b
Hydrotreating	kerosine, jet fuel	450 scf/b
Hydrotreating	diesel oil	800 scf/b
Hydrotreating	gas oil	1,200 scf/b
Hydrotreating	residua	>3,000 scf/b
Hydrocracking to produce:		
diesel	gas oil	1,730 scf/b
jet fuel	gas oil	1,870 scf/b
naphtha	gas oil	2,050 scf/b

[a] From Robinson and Dolbear, 2007 (Ref. 4).
[b] Hydrogen use capacities estimated from these data herein conservatively assign the kerosine/jet value to all "other distillate" hydrotreating; the naphtha value to unspecified "other" hydrotreating; and the diesel production value to all hydrocracking.
[c] Naphtha is a stream of mainly of gasoline-sized hydrocarbons; hydrotreating gasoline to meet fuel sulfur standards is a type of naphtha hydrotreating.

Figure 3. Hydrogen supply and demand, California refineries, 1995-2007



Data from Oil & Gas Journal (Ref. 3) and Table 2 (Robinson and Dolbear, 2007; Ref. 4). Hydroprocessing requirements applied per Table 2 note. Based on 90% of available production capacity.

Increasing GHG emissions from dirty crude

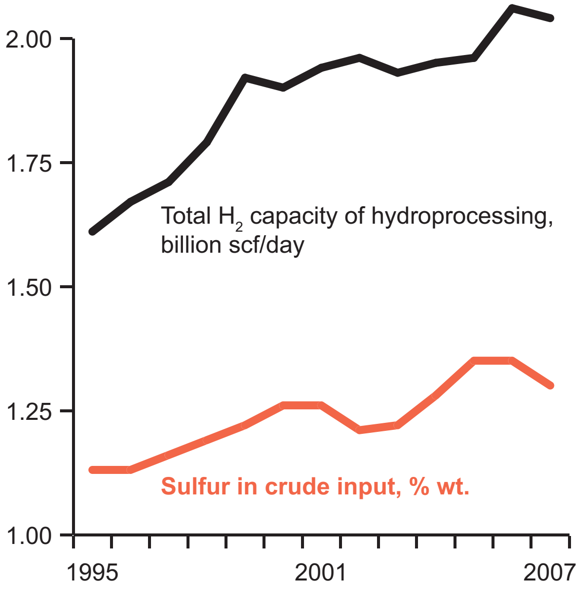
Third, the contaminants are embedded in the molecular structures of the large hydrocarbons in these heavier streams: removing them requires breaking up (“cracking”) those large compounds at higher temperatures and pressures. That more severe processing, in turn, requires more hydrogen to pressurize, quench and control the process reactions; so hydroprocessing each barrel of the more contaminated and heavier oil streams requires more hydrogen.

Sulfur contamination of the crude input to California refineries is estimated along with the total hydrogen capacity of their hydroprocessing units from 1995-2007 in Figure 4. As the sulfur content of their crude input increased from approximately 1.13% to 1.35%, their total hydrogen usage capacity increased from 1.61 billion to 2.04 billion cubic feet per day. Further, their hydrogen demand capacity is positively correlated with the sulfur content of their crude input (R-squared = 0.77; $p < 0.001$).

Sulfur increased in California refiners’ crude because they refined higher-sulfur imports in larger amounts as Californian and Alaskan supplies declined. See Table 3. Between 1995 and 2007 crude inputs from in-state and Alaska dropped by 70 million and 163 million barrels/year, respectively, while foreign crude inputs grew by 230 million b/y. This was a shift to dirtier crude. The foreign crude refined in California from 2005-2007 had an average of 1.55% sulfur as compared with 0.86% for Alaskan crude and 1.3% for San Joaquin Valley Heavy (SJVH)–the highest sulfur stream from California’s dominant remaining crude oil resource. *(5,6)*

The oil industry’s choice to replace dwindling domestic crude supplies with more contaminated sources of foreign crude has caused its hydrogen demand, hydrogen steam reforming production, and GHG emissions to increase.

Figure 4. Sulfur content of crude input and hydrogen demand, California refineries, 1995-2007



Crude quality data from USEIA (Ref. 5); and assay data for Alaskan and California crude oils (Ref. 6). Californian, Alaskan and imported crude volumes processed from Table 3. California crude input is conservatively assumed to be 100% San Joaquin Valley Heavy. All (100%) of available H_2 capacity is shown, based on references in Table 2 & Figure 3.

Table 3. Domestic and foreign crude inputs to California refineries, 1995-2025

thousands of barrels

	California	Alaska	Imports
1995	320,824	264,520	56,864
1996	322,238	267,492	77,628
1997	322,198	244,444	78,108
1998	317,817	221,983	104,653
1999	306,856	188,743	140,599
2000	326,371	163,233	169,105
2001	323,583	139,829	191,843
2002	317,321	143,685	199,994
2003	289,416	160,164	232,477
2004	274,396	141,967	238,484
2005	266,052	135,906	272,318
2006	254,498	105,684	295,306
2007	251,445	100,900	286,844
2015	197,923[b]	79,422[b]	361,844
2025	151,536[b]	60,809[b]	426,844

From the California Energy Commission (Refs. 7, 8).
[b] Calculated from 2007 total and state proportions.

Projection for 2008-2020

Current industry plans would further increase the steam reforming rates observed from 1995-2007.

Crude input basis: Refinery crude input quality provides one basis for estimating potential future emissions. The average sulfur content of imported crude with similar density to medium-heavy (146-153 kg/b) California crude that was processed by US refiners in 2007 was 2.76%. *(5)* Import streams with known capacity to expand as domestic supply declines include, among others, Western Canadian Heavy from Alberta's vast tar sands (WCH; ~3.3% sulfur), and Arab Heavy (~2.93% sulfur). *(6)* WCH and Arab Heavy are refined in-state already. *(5)* Assuming projected domestic supply declines and the necessary processing capacity, a mix of these and similar oils with 2.76-3.3% sulfur is likely to be half of the new imports refined by 2020. Calculations for this estimate are shown in Table 4.

Sulfur in the total 2020 statewide crude input could range from 1.78% if half the new imports are as contaminated as the current same-gravity US average, to 1.83% if they are Arab Heavy, to 1.96% if half the new imports are WCH.

Hydrogen use predicted with this potential sulfur contamination of the future crude input is shown by extrapolation from 1995-2007 observations in Figure 5. The 1995-2007 data predict 1.69 billion cf/d of refinery hydrogen capacity for each 1% increase in statewide crude sulfur content (R-squared = 0.77; $p < 0.001$). Predictions a, b and c are the same-gravity average (2.8 billion cf/d), Arab Heavy (2.89 bcf/d) and WCH (3.11 bcf/d) scenarios, respectively.

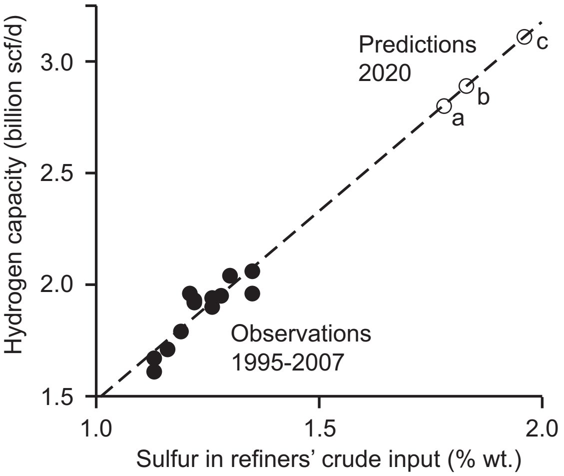
This information suggests that refinery hydrogen capacity could increase by 0.76-1.07 billion cf/d over the 2.04 billion cf/d of total hydroprocessing capacity to use hydrogen statewide in 2007.

Table 4. Estimated 2020 crude input sulfur

Oil to be 50% of new imports:	Gravity-average[a]	Arabian Heavy[b]	W. Canadian Heavy[c]
Crude (kg/b)			
Imports[d]	145	142	145
California[e]	148	148	148
Alaska[f]	137	137	137
Sulfur (% wt)			
Imports[d]	2.15	2.24	2.44
California[e]	1.30	1.30	1.30
Alaska[f]	0.86	0.86	0.86
Crude (MM t/y)[g]			
Imports[d]	57.3	55.9	57.2
California[e]	25.9	25.9	25.9
Alaska[f]	9.6	9.6	9.6
Total	92.8	91.4	92.7
Sulfur (MM t/y)			
Imports[d]	1.23	1.25	1.40
California[e]	0.34	0.34	0.34
Alaska[f]	0.08	0.08	0.08
Total	1.65	1.67	1.81
Weighted av. sulfur (% wt.)	**1.78**	**1.83**	**1.96**

[a] Average 2007 US imports with gravity from 146-153 kg/b (2.76% sulfur; Ref. 5).
[b] Arabian Heavy is 2.93% sulfur, 141 kg/b (Ref. 6).
[c] Western Canadian Heavy, 3.3% S, 148 kg/b. (Ref. 6).
[d] 50/50 blend of new import with 2005-2007 imports.
[e] All Calif. input conservatively set to SJVH (Ref. 6).
[f] ANS/Trans Alaska Pipeline (Ref. 6).
[g] From interpolation of 2015 & 2020 volumes in Table 3.

Figure 5. Hydrogen capacity predicted by crude input sulfur, Calif. refineries



Data for 1995-2007 observations from figures 3 and 4 (Refs. 3-6). Predictions from Table 4 and correlation line (R-squared = 0.77; $p < 0.001$).

Hydroprocessing capacity basis: Processing capacity provides another basis for estimating future emissions. In addition to the 240,000 b/d of hydrocracking capacity added by California refiners since 1995 *(3)*, at least 73,150 b/d of expanded hydrocracking capacity is planned by 2010. *(9,10,11)* More important, competition is likely to drive further expansion as refiners with less intensive hydroprocessing capacity per barrel of crude input "catch up" with those who are leading the trend. Calculations for this potential statewide increase in hydrogen demand by hydroprocessing are shown in Table 5.

The four California plants with the highest hydroprocessing capacities for hydrogen use/barrel of crude input–Chevron Richmond, Valero Wilmington, Tesoro Wilmington and ConocoPhillips Rodeo/Santa Maria–will have an estimated collective capacity to use approximately 1,534 cubic feet of hydrogen per barrel crude as of 2010. The two highest users will have a collective capacity of 1,755 cf/b. If other refiners match these levels, and accounting for other hydrogen recovery, this could result in 2.48-2.92 billion cf/d of total statewide capacity for hydrogen produced by steam reforming in 2020.

This 2.48-2.92 bcf/d estimate based on hydroprocessing capacity compares with 2.24-2.55 bcf/d based on crude input sulfur, when the predictions in Figure 5 are adjusted to account for other hydrogen recovery.

Steam reforming capacity basis: Steam reforming capacity provides another basis for estimating potential future emissions. At least three Bay Area refiners now plan new steam reforming plants, and the entire northern California industry could soon be linked by new hydrogen pipelines. See Figure 6. Based on plans announced publicly as of 2008 ConocoPhillips *(11)*, Chevron *(12)* and Valero *(13,14)* plan to add a net total of 320 million cf/d in steam reforming capacity; and pipe-

Table 5. Predicted 2020 hydroprocessing capacity for hydrogen statewide

High-use plants	H_2 bscf/d	Crude b/d	H_2 scf/b
Chevron-Richmond[a]	0.452	243,000	1,860
Valero-Wilmington	0.115	80,000	1,438
Tesoro-Wilmington	0.124	100,000	1,240
ConPh.-Rodeo/S.M.[a]	0.142	120,000	1,183

Scaled statewide to:	Top 4 plants	Top 2 plants
Subtotal bscf/d	0.833	0.567
Subtotal b/d	543,000	323,000
Hydrogen scf/b	1,534	1,755
Adjusted H_2 scf/b[b]	1,253	1,474
Statewide H_2 bscf/d[c]	**2.48**	**2.92**

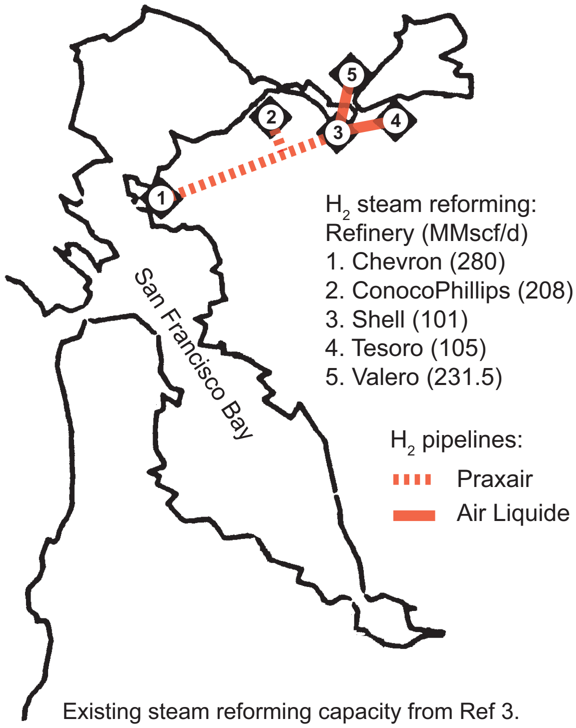
Data from Oil & Gas Journal (2007; Ref. 3); Chevron 6/29/06 BAAQMD Permit App. & 4/17/08 Title V Permit (Refs. 9, 10); ConocoPhillips EIR SCH #2005092028 (Ref. 11); Robinson and Dolbear, 2007 (Ref. 4) applied per Table 2 notes. Based on 100% of available capacity.

[a] Includes near-term capacity expansions (Refs. 9-11).

[b] Adjusted by subtracting cat-reforming & other recovery of 281 cf/b (statewide average in 2007; see Figure 3).

[c] From 1.983 MMb/d 2007 statewide input cap. (Ref. 3).

Figure 6. Northern California refiners' steam reforming and H_2 pipeline plans



Existing steam reforming capacity from Ref 3.
Planned 2010 SR capacity from Refs. 11-14.
Planned 2010 H_2 pipelines from Refs. 15, 16.

lines proposed by Praxair *(15)* and Air Liquide *(16)* would link hydrogen production and use by all five northern California refineries. This new infrastructure could be in place by 2010. Statewide capacity could grow to match it by 2020.

Calculations for estimated total statewide 2020 steam reforming capacity in this case are shown in Table 6. The 2010 northern California capacity totals an estimated 1,126 cubic feet per barrel of crude input capacity. Scaling this capacity to the 1,983,000 b/d statewide total crude capacity indicates that by 2020, California refineries could have steam reforming capacity totaling 2,232 million cubic feet per day.

Emissions projection: Table 7 shows projected emissions from hydrogen steam reforming. These are based on the same GHG emission factor used in the 1995-2007 estimate above (CO_2eq of carbon dioxide, methane and nitrous oxide), and 90% utilization of predicted capacity. Known steam reforming expansion proposals at just three plants could add 2.6 million tonnes of emissions per year by 2010. By 2020 steam reforming emissions from California refineries could total between 17.9 million and 23.4 million tonnes per year. That represents an increase of 7.63 million to 13.14 million tonnes/year above the 10.24 million t/y estimated in 2007.

Discussion

This projection is for potential statewide emissions in the absence of effective policy intervention. Estimates based on steam reforming capacity, hydroprocessing capacity to use hydrogen produced by steam reforming, and oil input contamination that requires this more intensive hydroprocessing consistently predict increased emissions. Together with observed increases in the same causal factors from 1995-2007, this provides evidence for a very large ongoing increase in pollution from refining dirtier oil. The range of

Table 6. Predicted 2020 statewide steam reforming capacity

N. California plant	H_2 bscf/d	Crude b/d	H_2 scf/b
Chevron-Richmond[a]	0.2800	243,000	1,152
ConPh.-Rodeo/S.M.[a]	0.2080	120,000	1,733
Shell-Martinez	0.1010	158,600	637
Tesoro-Golden Eagle	0.1050	161,000	652
Valero-Benicia	0.2315	139,500	1,659
Subtotal N.C. plants	0.9255	822,100	1,126
Scaled statewide	**2.2320**	**1,983,000**	**1,126**

Existing steam reforming (billions of standard cubic feet per day) and crude capacities (barrels/day) from Ref 3.
Planned 2010 SR capacity from Refs. 11-14.
Based on 100% available capacity.

Table 7. GHG emissions from steam reforming by California refineries in 2010 and 2020, projection scenarios based on seven estimate cases

Estimate case	Production rate (bscf/d)[a]	Emissions (MM t/y)[b]
Steam Reforming in 2010[c]	1.439	12.8
2020 cases		
Steam Reforming[d]	2.009	17.9
Similar-gravity avg. crude[e]	2.018	18.0
Arabian Heavy crude[e]	2.099	18.7
Hydroprocessing, highest 4[f]	2.232	19.9
W. Canadian Heavy crude[e]	2.297	20.4
Hydroprocessing, highest 2[f]	2.628	23.4
2020 projection		
High sulfur scenario		**17.9**
Higher sulfur scenario		**23.4**

[a] Steam reforming production of hydrogen in billions of standard cubic feet/day, estimated based on production at 90% of available capacity.
[b] Million tonnes/year, Carbon dioxide equivalent of CO_2, CH_4 and N_2O, based on an emission factor of 24.37 tonnes/MMscf (Refs. 1, 2).
[c] Based on 320 MMscfd net increase from Refs. 11-14.
[d] Based on steam reforming capacity (Table 6).
[e] Based on crude input quality (Table 4, Figure 5).
[f] Based on hydroprocessing capacity (Table 5).

emissions projected reflects uncertainty about the extent to which refinery feedstock could become more contaminated, hydroprocessing could expand to refine the dirtier oil, and steam reforming could expand to feed this hydroprocessing.

Uncertainty: Hydrogen use by a specific hydroprocessing unit may vary from the typical H_2 requirements in Table 2. *(4)* Hydrogen needs are affected by plant-specific oil input quality and process-specific feed, products, operating temperature and pressure, catalysts, hydrogen purity and hydrogen recovery. Estimates based on hydroprocessing capacity in Table 7 address this uncertainty by assigning the typical hydrogen requirements conservatively (see the notes in Table 2), applying them to all California plants on average, and checking those estimates against estimates based on crude quality and steam reforming capacity. The range of estimates based on hydroprocessing capacity overlaps with that based on oil quality and, at its low end (19.9 MMt/y), is within 11% of the estimate based on steam reforming capacity.

The estimate based on steam reforming capacity may be conservative. This estimate assumes that Los Angeles area plants will not use more hydrogen in 2020 than Bay Area plants use in 2010. LA area plants refine imports as a larger portion of their total crude input than Bay Area plants now *(3,5)*, and they have less access to the dominant remaining California crude resource, in the San Joaquin Valley, than the Bay Area plants. With high sulfur imports, by 2020 steam reforming per barrel of crude refined in the LA area might exceed that planned for 2010 in the Bay Area.

Crude input quality might worsen more than is estimated. Chevron plans to retool the largest Bay Area refinery for 3% sulfur crude. *(12)* Statewide crude input might exceed 2% sulfur by 2020 if new high-sulfur imports are more than half of new imports (a third of all crude input), lower sulfur domestic supplies decline more quickly, and/or the sulfur content of Arabian Heavy, Western Canadian Heavy or other major streams increases. In addition, contaminants such as nitrogen, nickel and vanadium further increase hydrogen use in hydroprocessing. Some high-sulfur crude imports have high levels of these other contaminants.

Combustion emissions will increase with the amount of steam reforming capacity utilized. The emission estimates in Table 7 are based on production at 90% of available capacity. This assumption is consistent with worldwide conditions *(3)* but California refineries tend to run closer to maximum capacity than the world average, and could further maximize their use of available steam reforming capacity by sharing hydrogen via existing and planned pipelines.

Emissions are estimated at 24.37 tonnes CO_2eq emission per million cubic feet of hydrogen produced, based on DOE and CARB data. *(1,2)* This emission factor falls within the range of emissions from new state-of-the-art steam reforming plants. *(11,12)* It may, however, underestimate actual emissions. It accounts for emissions from direct combustion in steam reformers but not the emissions from their electricity requirements or “fugitive” leaks. Recent work suggests fugitive emissions of methane could be significant. *(17)* This emission factor also assumes natural gas fuel, but refiners burn dirtier fuels along with natural gas. In addition, less efficient older steam reforming plants that have higher emissions may remain in service along with the new plants that are built.

Lastly, this projection assumes no increase in the total volume of crude refined beyond 2007. This also is a conservative assumption. *(8)*

Taken together, these considerations suggest that the projection in Table 7 is conservative.

Root cause: Analysis of data from 1995-2007 shows that refining higher sulfur crude increased hydrogen needs for hydroprocessing the lower quality oil, steam reforming to produce this extra hydrogen, and emissions from that increased production.

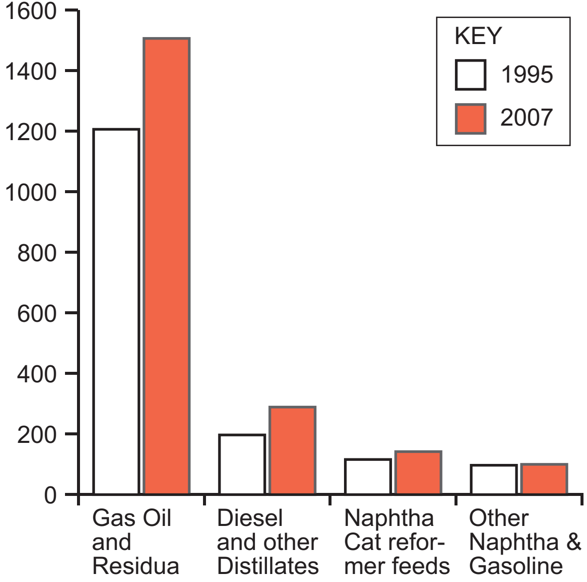
The need for severe hydroprocessing of the heavier streams from more contaminated crude, where the sulfur and other process catalyst poisons were concentrated, drove this increased hydrogen demand. See Figure 7. (Incidentally, this is also how we can know the industry's claim that new fuel standards drive its new hydrogen production is misleading.) Refining inherently dirtier feedstock is the root cause of the emissions increase observed now, and threatens to cause the future increase in emissions projected.

In this context, it is useful to consider the other major fossil energy user–electricity. Inherently dirtier power plant feedstock is acknowledged as a matter of policy. California requires public utilities to phase out use of electricity from coal-fired power plants. *(18)*

Other oil quality impacts: Making gasoline and diesel from low quality oils increases inputs of many pollutants *(6)*, requires more intensive conversion and conditioning by many refining processes, and requires more intensive extraction and pre-processing before the oil reaches refineries. *(19)* It requires more energy, burns more fossil fuel, and emits more toxic, smog-forming and climate-disrupting pollutants for each gallon of transportation fuel produced.

Elevated selenium in refinery inputs was associated with a tenfold increase in selenium discharge/barrel crude refined in the 1990s. *(20)*

Figure 7. Hydrogen use for hydroprocessing various feeds, California refineries, 1995 and 2007 (MMscf/d)



Data from References 3 and 4. Hydrogen requirements applied as described in Table 2 notes. Based on 100% of available capacity.

In 2007, an EPA study estimated that if high mercury oils become 0.5% of refinery inputs, potential mercury emissions from U.S. refineries might double. *(21)* In 2008, comparisons of recent Bay Area data found that increased flaring frequency and emissions concentrations were associated with increased sulfur in refinery crude inputs. *(22,23)* Hydroprocessing higher sulfur oil produces more hydrogen sulfide, a toxic gas that forms other toxic sulfur compounds when burned. This contributed to the increased flaring observed *(22)*, and may also increase toxic fugitive and combustion emissions from various refinery processes.

Brandt and Farrel estimated that a switch from conventional crude to extra-heavy oil and/or tar sands may cause GHG emissions by oil production and refining to increase from the current 22% to as much as 44% of total emissions from oil production, refining and vehicle tailpipes combined. *(19)* If this occurs, it may preclude the emission reductions necessary by 2020 and 2050 if we are to avoid the worst potential impacts from global warming.

Thus, other observed and predicted impacts of lower quality oil on releases of GHGs and other pollutants are consistent with those found here for steam reforming and point to a larger threat to our environmental health in communities near refineries, and to our global climate.

Policy implications: If public policy continues to allow it, an accelerating switch to more contaminated, lower quality oil could increase CO_2 equivalent emissions by 8-13 million tonnes/year by 2020 from hydrogen steam reforming alone. It might further increase toxic pollution impacts in communities near refineries and cause total emissions from transportation fuel production that overwhelm climate protection efforts. Inherently dirtier feedstock is the root cause of this problem.

Harnessing the chemical energy in low quality fossil resources creates more pollution per unit of useful energy produced. That is as true for vehicle fuels made from low quality oil as it is for electricity made from coal. California is addressing the feedstock problem for electricity by phasing out the use of coal-fired power. This solution–in the form of restrictions on oil input quality–can be applied to oil refineries.

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Appendices

Appendix A-1. Sulfur and specific gravity data for selected oil streams.

Named Stream	Sulfur % wt.	Gravity	Reference
Alaska North Slope (ANS)	0.86	0.860	Chevron (4/3/08 Subm. re. EIR SCH #2005072117)
San Joaquin Valley Heavy (SJVH)	1.30	0.934[a]	Sulfur from Ref. 12; see note a below for gravity
Arabian Heavy	2.87	0.889	www.caplinepipeline.com (3/1/02)
Arabian Heavy	2.99	0.889	www.caplinepipeline.com (10/22/06)
Access Western Blend (WCH)	3.99	0.924	www.crudemonitor.ca (July 2008)
Albian Heavy Synthetic (WCH)	2.54	0.936	www.crudemonitor.ca (3/07; 10/07; 5/08)
Albian Residual Blend (WCH)	2.69	0.933	www.crudemonitor.ca (9/06; 5/08)
Borealis Heavy Blend (WCH)	3.66	0.925	www.crudemonitor.ca (October 2007)
Bow River North (WCH)	2.89	0.928	www.crudemonitor.ca (8/06; 10/07; 5/08)
Bow River South (WCH)	2.80	0.914	www.crudemonitor.ca (10/07; 5/08)
Christina Synbit (WCH)	2.91	0.935	www.crudemonitor.ca (October 2007)
Cold Lake (WCH)	3.61	0.929	www.crudemonitor.ca (4/07; 10/07; 5/08)
Cold Lake Blend (WCH)	3.69	0.927	www.exxonmobil.com/apps/crude_oil (1/18/08)
Fosterton (WCH)	3.13	0.931	www.crudemonitor.ca (10/07; 5/08)
Lloyd Blend (WCH)	3.38	0.928	www.crudemonitor.ca (10/06; 10/07; 5/08)
Lloyd Kerrobert (WCH)	3.08	0.929	www.crudemonitor.ca (11/06; 10/07; 5/08)
Lloydminster (WCH)	3.15	0.930	www.crudemonitor.ca (October 2007)
Long Lake Heavy (WCH)	3.06	0.934	www.crudemonitor.ca (July 2008)
Mackay River (WCH)	2.78	0.936	www.crudemonitor.ca (10/07; 5/08)
Peace River Heavy (WCH)	4.76	0.930	www.crudemonitor.ca (10/07; 5/08)
Seal Heavy (WCH)	4.58	0.929	www.crudemonitor.ca (8/06; 5/08)
Smiley-Coleville (WCH)	2.95	0.934	www.crudemonitor.ca (11/06; 5/08)
Surmont Heavy Blend (WCH)	2.86	0.938	www.crudemonitor.ca (July 2008)
Wabasca Heavy (WCH)	3.79	0.928	www.crudemonitor.ca (4/06; 10/07; 5/08)
Western Canadian Blend (WCH)	3.03	0.929	www.crudemonitor.ca (6/06; 10/07; 5/08)
Western Canadian Select (WCH)	3.28	0.930	www.crudemonitor.ca (5/07; 5/08)

WCH is Western Canadian Heavy. [a] Gravity estimated conservatively based on the lightest crude classified as “heavy” by the Calif. Div. Oil and Gas and the Division’s 2006 Annual Report finding that statewide crude production, which is dominated by production from several very large San Joaquin Valley oil fields, has become lighter in recent years.

Appendix A-2. 2007 hydroprocessing and steam reforming capacities[a] of California refineries[b]

Refinery	Crude	Hydrocracking	Hydrotreating	H_2 Steam Reforming
Bakersfield area plants				
Big West Refining Bakersfield	65,000	23,500	21,900	24.7
Kern Oil Bakersfield	25,000	0	13,000	0.0
San Joaquin Refining Bakersfield	24,300	0	3,000	4.2
Bay Area plants				
Chevron Richmond	243,000	154,250	177,000	150.0
ConocoPhillips Rodeo & Santa Maria	120,000	37,000	73,000	88.0
Shell Martinez	158,600	37,900	117,950	101.0
Tesoro Golden Eagle	161,000	32,000	172,500	105.0
Valero Benicia	139,500	36,000	146,000	131.5
Los Angeles area plants				
Alon USA Paramount	54,000	0	29,000	0.0
BP Carson	264,500	45,000	244,700	105.0
Chevron El Segundo	260,000	46,000	201,000	217.0
ConocoPhillips Carson & Wilmington	138,700	24,750	135,850	100.8
ExxonMobil Torrance	149,500	20,500	143,500	146.0
Tesoro Wilmington	100,000	32,000	101,250	55.0
Valero Wilmington	80,000	0	139,500	50.0

[a] In barrels/calendar day (H_2 in MMscf/d) from Ref. 3. [b] California plants producing California gasoline and/or diesel.