THE FOUNDATION
FOR TAXPAYER AND
CONSUMER RIGHTS

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June 21, 2004

Honorable Bill Lockyer
Attorney General of California
1300 I Street, Ste 1740
Sacramento, CA 95814

Honorable Timothy Muris
Chairman, Federal Trade Commission
600 Pennsylvania Ave., N. W.
Washington D.C., 20580

Dear Attorney General Lockyer and Chairman Muris,

We are submitting the enclosed internal documents from Shell Oil which provide incontrovertible evidence the company has once again misled California about its stated reasons for the shutdown of Shell's Bakersfield refinery.

In addition, the documents reveal that Shell is planning to artificially reduce its supply of gasoline leading up the Labor Day holiday, which will almost certainly have the impact of raising prices at the pump. Shell is doing this by intentionally setting its routine maintenance schedule to curtail production at the peak drive time of summer – similar to tactics used by electricity generators during California's energy crisis.

Together with Shell's past misrepresentations to motorists, competitors and regulators about the closure of the Bakersfield refinery, these documents provide new evidence that Shell has engaged in a systemic pattern of deception about the closure. They also show Shell is poised to scale back output at its Bakersfield and Martinez refineries in the months leading up to the busiest driving holiday of the year.

The documents enclosed reveal the following facts.

- Shell is decreasing utilization during the summer months by setting its schedule for planned maintenance at both Bakersfield and Martinez refineries during maximum utilization periods when California is almost certain to be short on fuel. Cutting back operations in July and August is a recipe for low inventories, which lead to higher prices when the commodities market sees a shortage at a period of peak demand.

- There is no shortage of crude for both refineries, as Shell had claimed. There is ample crude to keep Bakersfield on line and Martinez running at maximum capacity. As an example, Shell is currently supplementing its San Juaquin crude with Ecuadorian crude at Martinez, leaving an adequate supply for Bakersfield to stay on line and Martinez to run at full capacity. Any problems in the future can be handled in the same fashion.

- Profits at Bakersfield are extreme. For example $11.4 million in May. Shell had stated that Bakersfield was closing because it was economically unviable. After being confronted with internal documents showing a $5 million profit last, Shell said such profits were not enough. This year already, according to the enclosed documents, Shell's profits from the Bakersfield refinery are $24.7 million – on track to be 10 times as high as last year.

We hope these documents give you the basis to take action against Shell in the next month. They show that, absent a regulatory response, Californians are likely to be paying closer to $3 per gallon at the pump by Labor Day.

The documents also reveal that August is too late for regulatory action. The time is now. We hope your agencies take the lead, but if you are unable to do so our consumer group is preparing its own case against Shell to be filed by late July in the absence of forward movement on this issue.

Our sincere hope is that the consulting firm of Mason Turner, hired by the California Attorney General's office, will find a credible buyer for this facility before the end of July, or that other actions by Shell will avert the coming crisis for California motorists.

Please keep us closely informed of your time table as we are preparing now for potential legal action before the end of July.

Best regards,

Jamie Court
President

Bay Valley June - August Planning Official Plan (Rev #0)

Summary

6/21/04 12:19	June		July - Average		August - Average		July - Dimer		July - CFH		August - CFH		August - Full	
DAYS	30		31		31		15		16		6		25	
Objective Function	$ 3,190		$ 2,508		$ 2,316		$ 2,771		$ 2,261		$ 1,941		$ 2,406	
Prices														
SF Very Heavy Coking Contr. Margin, $/bbl	$ 12.7		$ 12.1		$ 9.7		$ 12.1		$ 12.1		$ 9.7		$ 9.7	
Bay Carbob, cpg	136		132		121		132		132		121		121	
LA Carb Diesel, cpg	120		107		107		107		107		107		107	
LA Carb Jet, cpg	105		101		101		101		101		101		101	
Cat Feed, cpg	112		109		100		109		109		100		100	
Bay oxy SU - RU, cpg	8		10		7		10		10		7		7	
Crude Avail	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$
SJV	104	$ 1.98	87	$ 2.99	89		96	$ 6.18	79		74		93	
Blrdg Light (SJVL)	62	$ 2.46	60	$ 4.04	57	$ 2.02	60	$ 5.44	60	$ 2.73	57	$ 2.96	57	$ 1.79
Napo	40	$ 4.68	38	$ 3.79	39	$ 1.26	40	$ 7.82	37	$ -	36	$ -	40	$ 1.57
SBR Crude	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$
Light Crude	35.3		36.2		36.5		36.5		35.9		36.4		36.5	
Heavy Crude	26.8		22.3		18.5		17.5		26.9		18.6		18.5	
Total Crude	62.1		58.5		55.0		54.0		62.8		55.0		55.0	
SBR Products														
Total Finished Mogas	22.8	$ (0.92)	22.2	$ (1.34)	21.7	$ (0.08)	21.6	$ (1.34)	22.7	$ (1.34)	21.7	$ (0.08)	21.7	$ (0.08)
Total Finished Diesel	19.3	$ -	18.0	$ (0.96)	16.6	$ (0.38)	16.5	$ (1.98)	19.3	$ -	16.6	$ (1.98)	16.6	$ -
Light Product Make	42.1		40.2		38.3		38.1		42.1		38.2		38.3	
RGO	15.0		13.5		15.0		11.7		15.1		13.1		15.5	

SBR Processing Units	EDC Factor	Rated Capacity	MBPD	%Rated	MBPD	%Rated	MBPD	%Rated	MBPD	%Rated	MBPD	%Rated	MBPD	%Rated	MBPD	%Rated
Crude Unit	1.0	70.0	62.1	89%	58.5	84%	55.0	79%	54.0	77%	62.8	90%	55.0	79%	55.0	79%
Vacuum Tower	1.0	39.3	31.1	79%	28.4	72%	26.0	66%	25.2	64%	31.4	80%	26.0	66%	26.0	66%
DCU CHARGE	7.5	22.0	20.0	91%	17.5	80%	15.4	70%	15.9	72%	19.1	87%	15.4	70%	15.4	70%
HTU#1	2.7	7.0	7.0	100%	7.0	100%	7.0	100%	7.0	100%	7.0	100%	7.0	100%	7.0	100%
CRU#1	4.3	6.8	5.6	82%	5.1	75%	4.4	65%	4.3	64%	5.8	85%	4.4	65%	4.4	65%
HTU#3	2.7	6.8	4.3	64%	3.8	55%	2.8	41%	3.5	52%	4.0	59%	2.7	40%	2.8	41%
CRU#4	4.3	8.0	7.4	93%	7.6	94%	7.9	98%	7.9	99%	7.2	90%	7.9	98%	7.9	98%
CD Hydro	2.9	9.4	12.0	127%	12.0	127%	12.2	130%	12.0	127%	12.0	127%	12.2	130%	12.2	130%
Hydrogen Plant	3.0	24.6	23.8	97%	23.1	94%	22.0	90%	22.5	92%	23.6	96%	22.0	90%	22.0	90%
HCU 1st Stage	10.6	24.0	24.0	100%	24.0	100%	24.0	100%	24.0	100%	24.0	100%	24.0	100%	24.0	100%
HDA 2nd Stage	3.5	15.0	15.0	100%	15.0	100%	15.0	100%	15.0	100%	15.0	100%	15.0	100%	15.0	100%
HC 2nd Stage			6.0		6.0		6.0		6.0		6.0		6.0		6.0	
MAD Capacity			2.4		2.4		2.4		2.4		2.4		2.4		2.4	
Depetanizer	2.0	6.0	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
Offsites, Phosam, PRISM, Steam, SRU, TGTU		24.0	39.2		37.7		36.3		36.6		38.7		36.3		36.3	
EDC (w/o MHCU)		819.9	782.5		751.2		721.0		725.8		775.1		721.0		721.0	
%EDC Util. (w/o MHCU)			95.4%		91.6%		87.9%		88.5%		94.5%		87.9%		87.9%	

SMR Crude	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$	MBPD	Shadow$
SJV	77.4		65.5		71.3		79.2		52.5		56.2		74.9	
Blrdg Light (SJVL)	26.7		23.8		20.5		23.5		24.1		20.6		20.5	
Rerun	0.0		0.0		0.0		0.0		0.0		0.0		0.0	
Albian Syn Crude	0.0		0.0		0.0		0.0		0.0		0.0		0.0	
Oriente	0.0	$ 2.09	0.0	$ 2.66	0.1	$ (0.04)	0.0	$ 5.73	0.0	$ (0.22)	0.0	$ (0.18)	0.1	
Napo	40.0	$ 4.68	38.4	$ 3.79	39.3	$ 1.26	40.0	$ 7.82	36.9		36.4		40.0	$ 1.57
Maya	0.0	$ 33.46	0.0	$ 32.65	0.0	$ 32.36	0.0	$ 32.65	0.0	$ 32.65	0.0	$ 32.36	0.0	$ 32.36
Natural Gasoline	0.0		0.0		0.0		0.0		0.0		0.0		0.0	
Total Other Crude	40.0		38.4		39.4		40.0		36.9		36.5		40.1	
Total Crude	144.2		127.7		131.2		142.8		113.6		113.2		135.5	
SMR Products														
Total Finished Mogas	92.2		88.2		92.7		89.1		87.4		90.6		93.2	
Premium Mogas	23.7	$ (0.49)	26.4	$ 1.17	24.6	$ (0.21)	26.4	$ 0.05	26.5	$ 2.23	26.4	$ 0.13	24.2	$ (0.29)
Regular Mogas	68.5	$ -	61.8	$ -	68.1	$ -	62.7	$ -	60.9	$ -	64.2	$ -	69.0	$ -
Total Finished Jet	28.2	$ (2.23)	21.0	$ (2.56)	22.5	$ (0.79)	22.3	$ (0.91)	19.7	$ (4.11)	19.7	$ (4.09)	23.2	$ -
Total Finished Diesel	23.0	$ 2.75	20.0	$ (1.02)	21.9	$ 0.52	23.0	$ 0.26	17.2	$ (2.23)	17.3	$ (2.23)	23.0	$ 1.18
Light Product Make	143.4		129.2		137.1		134.4		124.3		127.5		139.4	
Cat Feed (Shdw for 2500 ppm N)	2.6	$ -	5.0	$ (0.00)	5.1	$ 3.54	0.0	$ (0.01)	9.8	$ -	5.4	$ -	5.0	$ 4.40
Total Fuel Oil	0.0	$ (4.92)	0.0	$ (4.56)	0.0	$ (3.28)	0.0	$ (7.79)	0.0	$ (1.53)	0.0	$ (1.37)	0.0	$ (3.74)
Asphalt	4.5	$ 3.30	3.4	$ 0.98	4.5	$ 7.40	2.8	$ (1.37)	4.0	$ 3.18	4.5	$ 5.51	4.5	$ 7.85
Inventory - Pitch	-2.0		-1.3		-2.0		-0.5		-2.0		-2.0		-2.0	
Inventory - Cat Feed	10.0		-3.4		-7.4		10.0		-16.0		-16.0		-5.3	

SMR Processing Units	EDC Factor	Rated Capacity	MBPD	%Rated	MBPD	%Rated	MBPD	%Rated	MBPD	%Rated	MBPD	%Rated	MBPD	%Rated	MBPD	%Rated
DISTILLING-HYDROPROCESSING																
Distilling	1.0	145.0	147.0	101%	132.4	91%	140.2	97%	142.8	98%	122.7	85%	120.3	83%	145.0	100%
Flasher	1.0	95.0	97.1	102%	87.6	92%	94.2	99%	95.3	100%	80.3	85%	79.6	84%	97.7	103%
Naphtha Hydrotreater	2.5	28.0	20.4	73%	18.3	65%	18.4	66%	18.2	65%	18.3	65%	18.3	65%	18.4	66%
Gas Oil Hydrotreater	2.7	24.0	26.0	108%	23.4	97%	22.3	93%	25.4	106%	21.5	89%	19.2	80%	23.1	96%
Hydrocracker	8.0	39.0	41.8	107%	37.2	95%	39.6	102%	37.7	97%	36.8	94%	36.7	94%	40.3	103%
Cat Reformer	3.5	31.0	31.0	100%	31.0	100%	31.0	100%	31.0	100%	31.0	100%	31.0	100%	31.0	100%
H2 Plant 1 (MMSCFD)	4.2	67.0	47.4	71%	25.5	38%	36.1	54%	39.2	59%	12.7	19%	12.7	19%	41.8	62%
CRACKED PRODUCTS																
Cat Feed HT	4.3	55.0	58.0	105%	26.3	48%	40.7	74%	54.3	99%	0.0	0%	0.0	0%	50.4	92%
Cat Cracker	8.2	73.0	67.8	93%	62.7	86%	68.5	94%	65.6	90%	60.0	82%	63.0	86%	69.8	96%
Cat Gaso HT	2.5	23.0	23.0	100%	21.8	95%	23.9	104%	22.4	97%	21.4	93%	22.2	97%	24.3	106%
Alkylate Product	8.0	11.5	12.5	109%	12.5	109%	12.5	109%	12.5	109%	12.5	109%	12.5	109%	12.5	109%
OPCEN																
Flexicoker	12.6	22.5	22.0	98%	22.0	98%	22.0	98%	22.0	98%	22.0	98%	22.0	98%	22.0	98%
Dist Sats Unit	2.5	20.0	15.3	77%	13.5	67%	14.8	74%	15.5	77%	11.6	58%	12.1	60%	15.4	77%
Dimersol Product	7.5	2.7	2.5	93%	1.9	71%	2.5	93%	2.2	83%	1.6	61%	2.3	86%	2.6	95%
H2 Plant 2 (MMSCFD)	4.2	40.0	32.3	81%	32.3	81%	32.3	81%	32.3	81%	32.3	81%	32.3	81%	32.3	81%
CLEAN FUELS																
HP3 (MMSCFD)	4.2	88.5	87.1	98%	87.1	98%	87.1	98%	87.1	98%	87.1	98%	87.1	98%	87.1	98%
De-Cyclohexanizer	1.0	42.0	42.8	102%	42.5	101%	41.4	99%	42.4	101%	42.6	101%	40.8	97%	41.5	99%
Isomerization	3.7	15.0	11.9	79%	11.6	77%	10.6	71%	11.5	77%	11.7	78%	10.0	67%	10.7	72%
CGDP	2.5	40.0	38.0	95%	35.8	90%	39.3	98%	36.9	92%	34.8	87%	36.4	91%	40.0	100%
Delayed Coker	8.6	26.0	28.0	108%	21.9	84%	23.3	90%	27.1	104%	17.0	65%	17.0	65%	24.8	95%
Pitch Rate			24.0		18.8		20.1		23.2		14.6		14.7		21.4	
Distillate Hydrotreater	6.2	22.0	22.0	100%	22.1	100%	23.8	108%	20.8	95%	23.3	106%	23.2	106%	23.9	109%
Hvy Gasoline Hydrotreater	2.5	18.1	17.3	96%	15.2	84%	16.5	91%	16.8	93%	13.8	76%	14.1	78%	17.1	94%
Other EDC + Sulfur + COGEN	**	495	495		495		495		495		495		495		495	
UEDC		4054	3905		3487		3714		3767		3225		3245		3827	
%EDC Utilization			96.3%		86.0%		91.6%		92.9%		79.6%		80.0%		94.4%	
BV EDC Utilization (w/o MHCU)		4874	4688		4239		4435		4492		4000		3966		4548	
BV %EDC Util (w/o MHCU)			96.2%		87.0%		91.0%		92.2%		82.1%		81.4%		93.3%	

The following information should be considered strictly confidential and is not to be shared with anyone outside Shell.

Bay Valley Complex June through August Production Forecast:

Summary
June's total domestic crude avails for BVC are 166 MBPD. SBR will process 62 MBPD domestic and SMR will process the remaining 104 MBPD domestic, 40 MBPD of Napo, and 2.5 MBPD of Ellwood. June's planned BVC capacity utilization is 96.2% with SMR at 96.3% and SBR at 95.4%.

The planned BVC light products total 115 MBPD of mogas, 28.2 MBPD of jet, and 42.3 MBPD of diesel. The planned BVC heavy products total 15 MBPD of RGO (11 MBPD destined for SMR and 4 MBPD to LA), 3.6 MBPD of FOC, and 4.5 MBPD of asphalt.

Planned Rates (MBPD) and Capacity Utilizations

	EDC Factor	"Rated"	PIMS Max-June	June	July	August
BVC						
%EDC Utilization	-	-	-	96.2	87.0	91.0
SBR						
Crude Unit	1.0	70.0	68.0	62.1	58.5	55.0
DCU	7.5	22.0	20.0	20.0	17.5	15.4
HCU 1st Stg	10.6	24.0	24.0	24.0	24.0	24.0
%EDC Utilization	-	-	-	95.4	91.6	87.9
SMR						
Crude Unit	1.0	145.0	147.0	147.0	132.4	140.2
CRU	3.5	31.0	31.0	31.0	31.0	31.0
HCU	8.0	39.0	42.0	41.8	37.2	39.6
CFH	4.3	55.0	58.0	58.0	26.3	40.7
CCU	8.2	73.0	70.0	67.8	62.7	68.5
Alky	8.0	11.5	12.5	12.5	12.5	12.5
FXU	12.8	22.5	22.0	22.0	22.0	22.0
DCU	8.6	26.0	28.0	28.0	21.9	23.3
DHT	6.2	22.0	22.0	22.0	22.1	23.8
%EDC Utilization	-	-	-	96.3	86.0	91.6

The capacity utilization for July is reduced due to a planned ten-day Dimersol shutdown for cleaning, a planned 25-day COB #1 shutdown for turnaround, a planned 22-day CFH shutdown for turnaround, a planned five-day CU slowdown for the crude rate project, and a planned ten-day SMR DCU spall. August's capacity utilization is impacted by the CFH and COB #1 turnarounds that are planned to finish in the first six days of August. Update – The SMR DCU spall has been moved to August. This is not reflected in this plan.

Price Premises

The plan was based on the margins in the attached table.

Actual and Plan Margin	5/25/04 Actual	June Plan	July Plan	August Plan
Very Heavy Coking Contribution Margin	$14.03	$12.7	$12.1	$9.7
Bay RU CARBOB, cpg	154.0	137.3	132.7	121.7
Bay PUL-RUL CARBOB, cpg	10	8	10.5	7.5
LA Jet Pipe, cpg	120.5	102.7	98.4	98.6
Bay CARB Diesel, cpg	122.0	125.7	112.4	112.6
LS Cat Feed, cpg	118.8	111.7	109.0	100.3

(LA prices include 4 cpg discount for transportation and terminal costs.)

Unit Down Time

June

This plan reflects the increased Napo rates of 40 MBPD, and the processing of the last 75 MB of Ellwood crude leftover in tankage.

July

The Dimersol unit shutdown planned for July 12th for 10 days is reflected in the July plan. The CCU rate is slowed to ~55 MBPD during this time to reduce the load on the fuel system.

COB #1 will shutdown on July 12th for a 25-day shutdown, and the CFH will shutdown July 16th for a 22-day turnaround. The plan reflects the expected CCU feed rate limitation estimated at 63 MBPD during the COB #1 shutdown.

The plan includes the CU slowdown on July 18th to 105 MB/D for 3 days for project work associated with the rerate of the CU. Update – The CU slowdown has been increased to four days to account for the ramp down and ramp up time associated with the slow down. The actual project work is still expected to be 3 days. This is not reflected in this plan.

A ten-day SMR DCU spall is premised in the plan for July. Update – The SMR DCU spall has been moved to August. This is not reflected in this plan.

August

The first six days of August are impacted by the CFH and COB #1 turnarounds.

Plan Highlights

1. The June plan drives many units to full.
2. SMR pitch inventory is premised with a draw of 2.0 MBPD for June and July. Threat - We continue to struggle with understanding our pitch balance (inside and outside the model) and we still have the potential to build instead of pull. Currently, we are planning for asphalt to pick up; however, this is not a guarantee.
3. A cat feed sale of 2.6 MB/D was identified in the June plan.
4. Napo to 40 MBPD will be tested in June.

Operational Issues Potentially Impacting the Plan

1. DSU catalyst activity decline may limit our abilities to make diesel/jet.
2. CCU expander hot/cold spall.
3. Dimersol's ability to handle heat and the impact to the Alky unit and fuel system.

Drivers for June

1. Reliability in order to run full for June.
2. Maximizing the DHT and CFH throughputs prior to the CFH T/A.
3. Volatiles handling via fuel / rail / trucks.

Unplanned Items with Impacts or with Possible Impacts to June

1. There is the potential that BVC will have more cutter (FOC) than originally planned. The CFH has reduced the feed rate to 55 MBPD versus the planned 58 MBPD so FOC is currently being backed out in order to make room for the available cat feed.
2. The CU will possibly be rerated to 152 MBPD in June.

Open Items

- HFD cooling limitations during the CFH shutdown
- Dimersol shutdown timing
- FOC/CFH feed rate issue
- CU rerate to 152 MBPD

Date: 5/24/04

Refinery: Martinez

	Business Plan	Month End Projection	Better (Worse)
Crude (Mbpd)	131.0	138.8	7.8
Other Inputs (Mbpd)	23.8	27.4	3.6
Total Inputs (Mbpd)	154.8	166.2	11.4
$MM			
Revenue	148.3	282.7	134.4
Product Costs	91.1	171.5	(80.4)
Hydrocarbon Gross Margin	57.2	111.2	54.0
Energy/Utility Costs	23.9	28.3	(4.4)
Gross Margin	33.3	82.9	49.6
Non Energy Variable Costs	3.9	4.0	(0.1)
Salaries and Wages	6.3	8.6	(2.3)
Other Base Operating	4.0	4.1	(0.1)
Casualty Loss	0.1	0.1	(0.0)
Environmental Remediation	-	-	-
Other Fixed Expenses	2.5	2.7	(0.2)
Turnaround	(0.0)	0.1	(0.2)
Dismantlement	0.3	-	0.3
Operating Expenses	17.0	19.6	(2.7)
Support Services (includes Supply)	1.5	1.5	-
Allocations	-	-	-
Overhead Expenses	1.5	1.5	-
EBITDA	14.1	61.8	47.7
Depreciation & other expenses	9.0	8.2	0.8

NIBT	5.1	53.6	48.5
Taxes	1.8	19.5	17.6
NIBIAT	3.2	34.1	30.9
Gross Margin $s/BBL	$ 6.93	$ 16.09	$ 9.15
Plan Vs. Estimated Marker $s/BBL	$ 5.66	$ 17.80	$ 12.14

Variance Explanations *

1) Gross Margin

Hydrocarbon Gross Margin higher than Op Plan: Price = $47.4MM Volume = $6.6MM

<u>Hydrocarbon Price</u>

49.3 **Core Marker Margin -**

SF Very Heavy Coking Plan **$5.66/bbl**; SF Very Heavy Coking Mont average **$17.80/bbl**

Marker margin does not include Cat Feed, Iso-Octane, or CARBOB

Secondary Margin:

(4.1) S&D Hurt

(1.1) Transportation cost running higher than Plan due to higher cost and higher marine movement

5.9 Own Produced Fuel price higher than Plan

(2.6) LIFO hurt due to Feedstock built (preperation for CFH T/A)of 243MB with price increase of $9 and Jet of 90MB with price increase of $17

2.1 Higher Coke and Asphalt pricess

(2.9) Mogas Component - Primarily Isomaerate 110MB

0.8 Other

47.4 TOTAL (Hydrocarbon Price)

<u>Hydrocarbon Volume - (Volume * Actual Price)</u>

3.7 Own Produced Fuel volume higher than Plan estimate 622 vs. Plan of 493 - NLFEB

3.6 Higher Gasoline mix production.

(1.9) E549 repair $100M and Cost of Hydrogen shortage $1.8MM due to HP1 LTS Catalyst change

1.2	Higher Low Sulfur Cat feed volume due to CFH T/A in June .
6.6	**TOTAL (Hydrocarbon Volume)**

Energy/Utilities Price

Plan $29.75 vs. Projection $41.166 - MTD Utilization 94%

(5.9)	Own Produced Fuel price higher than Plan
5.0	BP doesn't include credits received from HP3 -Own Produced Fuel
(2.8)	Purchase fuel price higher than plan
0.6	Steam price Estimate $10.69 vs. Plan of $7.74
(3.1)	**TOTAL (Energy/Utilities Volume)**

Energy/Utilities Volume

(3.7)	Own Produced Fuel volume higher than Plan estimate 622 vs. Plan of 493 - NLFEB
2.6	Purchase fuel volume lower (Plan 219 vs. estimate 120.6 - NLFEB)
(0.2)	Other
(1.3)	**Total (Energy/Util Volume)**
49.6	**TOTAL (GROSS MARGIN)**

2) Operating Expenses

Non-Energy (include explanation)

0.8 Catalyst

HCU scheduled for May in BP for $1.7MM tentatively moved to Jan 2005

HP1 & LTS scheduled for Aug were moved up to May totalling ($0.9MM)

(0.7) Chemicals
($0.6MM) Increased Flexorb usage due to issues with Flexorb startup .
Purchase of RO membrane filters for water - ($0.1MM) .
(0.2) Other
Hp-3 credit reclassed to Energy expense

(0.1) TOTAL (Non-Energy)

Fixed Costs

(2.3) Salaries and Wages
$1.2MM cost synergy from forming BVC was not achieved .
$1.1MM Higher vacation accrual $0.5MM & Benefits $0.6MM . Benefits running 10% higher than Plan
Repairs and Maintenance -

Casualty Loss -

Environmental Remediation -

(0.4) Contract Work -
($0.2MM) higher base fee for SGS
($0.2MM) Other
(0.1) Turnaround -
CFH/COB T/A pre-planning
Other Fixed Expenses -

0.3 Dismantlement
Lower due to ratable Plan

(2.5)	**TOTAL (FIXED COST)**

0.8 Depreciation & Amortization

Accelerated depreciation for LDU write off deferred till Dec

PREMISE CHANGES -- Significant changes to basic drivers premised in plan	
Volumes:	-
	-
Margins:	-
Expenses:	
	-

Date: 5/24/04

Refinery: Bakersfield

	Business Plan	Month End Projection	Better (Worse)
Crude (Mbpd)	63.0	63.2	0.2
Other Inputs (Mbpd)	10.0	11.0	0.9
Total Inputs (Mbpd)	73.0	74.2	1.2
$MM			
Revenue	53.7	93.4	39.8
Product Costs	39.4	60.0	(20.6)
Hydrocarbon Gross Margin	14.3	33.4	(19.2)
Energy/Utility Costs	4.2	6.4	(2.2)
Gross Margin	10.1	27.0	16.9
Non Energy Variable Costs	0.4	0.4	(0.0)
Salaries and Wages	3.5	2.7	0.7
Other Base Operating	0.9	0.9	0.0
Casualty Loss	0.0	0.0	0.0
Environmental Remediation	0.0	0.0	-
Other Fixed Expenses	1.0	1.1	(0.1)
Turnaround	(0.0)	0.0	(0.0)
Dismantlement	0.0	0.0	-
Operating Expenses	5.8	5.1	0.7
Support Services (includes Supply)	0.7	0.7	0.0
Allocations	0.0	0.0	-
Overhead Expenses	0.7	0.7	0.0
EBITDA	3.6	21.2	17.6
Depreciation & other expenses	3.3	3.3	(0.0)

NIBT	0.3	17.9	17.6
Taxes	0.1	6.5	6.4
NIBIAT	0.2	11.4	11.2
Gross Margin $s/BBL	$ 4.46	$ 11.76	$ 7.30
Plan Vs. Estimated Marker $s/BBL	$ 6.02	$ 22.66	$ 16.64

Variance Explanations *

1) Gross Margin

Hydrocarbon Gross Margin $19.2 higher than Op Plan: Price = $18.6MM Volume = $.5MM

Hydrocarbon Price

(19.1) **Core Marker Margin** - Coker Plan Margin, $22.66/bbl, Estimate Margin $11.76/bbl
Currently experiencing strong west coast margins. Regular CARBOB gasoline averaging almost $70/bbl
Kern Crude averaging apx. $33.75/bbl

Secondary Margin:

0.5 Prior Period price adjustments on alkylate and iso octane (S&D Bucket)

(18.6) TOTAL (Hydrocarbon Price)

Hydrocarbon Volume - (Volume * Actual Price)

(0.5) Anticapate to pull approximately 100K bbls. Half of which is RGO from our outside plant. The balance is the net of the remainder products.
The Coker is slowed today for a boiler inspection on SRU #2. All the heaters will be decoked during the 10 day slowdown
All other units running well.

(0.5) TOTAL (Hydrocarbon Volume)

Energy/Utilities Price

1.8 Own-Prod Fuel - Plan $14.76/bbl - Estimate $33.07/bbl
0.5 Purch Nat Gas - Plan $25.29/bbl - Estimate $36.77/bbl
(0.2) Purch Electricity -Plan $.107 kw vs Estimate $.093 kw
0.1 Other -

2.2 TOTAL (Energy/Utilities Volume)

Energy/Utilities Volume

0.0 Own-Prod Fuel - Plan Volume
0.0 Purch Nat Gas Plan
0.0 Purch Electricity
0.0 Other
0.0 Total (Energy/Util Volume)

(16.9)	**TOTAL (GROSS MARGIN)**

2) Operating Expenses

<u>Non-Energy (include explanation)</u>

	Catalyst
	Chemicals
	Other
0.0	**TOTAL (Non-Energy)**

Fixed Costs

Forecasted Fixed Costs are $.7MM above/below Plan due to the following (include explanation):

0.7	Salaries and Wages	Reduction for severance and for employees that have transferred or resigned.
	Repairs and Maintenance -	
	Casualty Loss -	
	Environmental Remediation -	

0.2	Contract Work -	Reduction in scope of work due to plant closure
	Turnaround -	
(0.3)	Other Fixed Expenses -	Estimated accrual of relocation > severance
0.7	**TOTAL (FIXED COST)**	

PREMISE CHANGES -- Significant changes to basic drivers premised in plan	
Volumes:	- -
Margins:	-
Expenses:	Anticipate $7.0MM for Tricor Legal settlement. Estimate included in Other refining. -

$MM NIAT Help /(Hurt)	May Projection	Business Plan	YTD Projection	YTD Business Plan
Bakersfield	$ 11.4	$ 0.2	$ 24.7	$ (6.8)
Martinez	$ 34.1	$ 3.2	$ 91.4	$ 36.2
Bay Valley	**$ 45.5**	**$ 3.4**	**$ 116.1**	**$ 29.4**