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Additional submitted attachment is included below.

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May 17, 2024

California Energy Commission
Docket Unit, MS-4
Docket No. 23-SB-02
715 P Street
Sacramento, California 95814
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RE: SB X1-2 Draft Transportation Fuels Assessment

Thank you for the opportunity to comment on the California Energy Commission's (CEC) "Draft Transportation Fuels Assessment" (CEC-200-2024-003-D), published on April 12, 2024, and the focus of the CEC workshop on May 3, 2024.

WSPA is a non-profit trade association representing companies that import and export, explore, produce, refine, transport, and market petroleum, petroleum products, natural gas, and other energy supplies in California and four other western states, and has been an active participant in transportation fuels planning issues for over 30 years.

The CEC's Draft Transportation Fuels Assessment is a reasonable initial draft and recognizes California's fundamental structural gasoline supply challenges – but much work is left to be done.

With the Draft Transportation Fuels Assessment (herein referred to as Draft), the CEC, working with the California Air Resources Board (CARB), has provided the public with a useful primer on the California liquid transportation fuels system, focused primarily on gasoline. The description of the realities of the California transportation fuel system makes adequate reference to both the structure and the structural risks associated with refining and distributing liquid fuels in the State.

In the Draft's Executive Summary, the CEC acknowledges the basic reality of California's gasoline supply dynamics: California's constrained local refining capacity, limited number of available local suppliers, regionalized supply chains, reliance on marine transportation of fuel supplies, and stringent fuel specification requirements combine to make it a "fuel island" isolated from the rest of the nation's transportation fuels market. The limited number of spot market gasoline transactions in California also give the local spot market an outsized influence on California prices that is not seen elsewhere in the country. At the same time, the CEC emphasizes that "gasoline remains California's dominant transportation fuel" and demand will remain robust well beyond 2035. As the CEC correctly points out, "[t]hese vehicles will need fuel to operate, and many of the vehicles may be owned by lower income individuals and families, making it even more compelling to identify ways to ensure an affordable, reliable, equitable, and safe supply."[1]

The first chapter describes the California "fuel landscape" and briefly dwells on market dynamics,

[1] Draft, p. ES-1

including price spikes and potential causes of disruption to the system. It emphasizes the mandate of Senate Bill (SB) X1-2 (2023) to the State agencies and explains how the CEC and CARB addressed this mandate in the Draft.

The chapter also focuses on anticipated changes to demand for fuels in the near future, and expectations of how the market will respond to declining demand. The declines in demand, according to the analysis, will be due in large part to the eventual electrification of the light duty vehicle fleet and anticipated reductions in vehicle miles traveled (VMTs) over time by gasoline engine powered vehicles. The chapter further explores pathways by which refiners might attempt to keep pace with declining demand and identifies "how the state might intervene to assure an affordable, reliable, equitable, and safe supply of gasoline for consumers who need it."[2]

The second chapter undertakes a high-level "primer on petroleum" including crude oil sources and refining basics. The narrative attempts to give the public a very basic education on blendstocks, California gasoline requirements (such as California Reformulated Blendstocks for Oxygenate Blending (CARBOB)), and briefly explains the differences between summer and winter blends, based on Reid Vapor Pressure (RVP). The chapter concludes with another high-level discussion of the distribution system from refinery, to spot market, to retail, including brief discussions of spot markets and the differences between branded and unbranded gasoline sales at the pump.

Finally, a third chapter presents in very brief form about a dozen "policy options" for future consideration by the CEC for meeting the mandates in SB X1-2 to ensure market stability and benefits to consumers.

The Draft fails to address critical elements of the supply chain.

SB X1-2 directs the CEC to submit an assessment to the Legislature and to the Governor that "[i]dentifies methods to ensure a reliable supply of affordable and safe transportation fuels in California."[3] The statute further calls for "the evaluation of oil and gas extraction and refining"[4], but this Draft only covers the supply of transportation fuels, primarily gasoline. A proper transportation fuels assessment must look at all current fuels, e.g., gasoline, diesel (petroleum and renewable), jet (petroleum and SAF), LPG, natural gas (CNG, LNG, and RNG), hydrogen (combustion and fuel cell), and electricity. Such an assessment should also review the entire value chain for each transportation fuel. For example, petroleum fuels segments would include upstream, pipelines, marine infrastructure, storage terminals, refineries, distribution, and retail service station networks, while a review of the electricity value chain would include generation, the grid (transmission and distribution), charging networks (industrial, commercial, single-family, multi-family), and zero-emission vehicle (ZEV) availability.

WSPA notes that the CEC had the resources in hand to include assessments for diesel and aviation fuel by using the same outlooks used for their gasoline assessment, as is reflected in the data presented in the 2023 Independent Energy Policy Report (IEPR).[5] Each of these fuel sources

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[2] Draft, page 17.

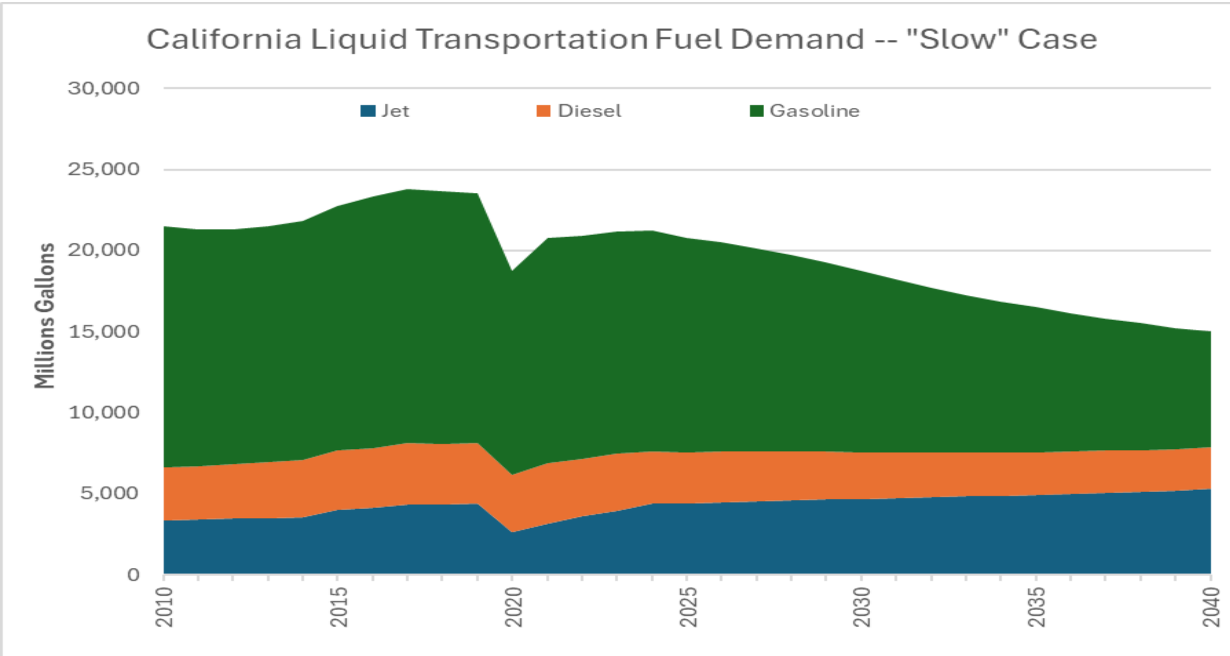
[3] Cal. Pub. Res. Code (PRC) § 25371(a)(2)

[4] PRC § 25371(a)(2)

[5] Bailey, Stephanie, Jennifer Campagna, Mathew Cooper, Quentin Gee, Heidi Javanbakht, and Ben Wender. 2023. 2023 Integrated Energy Policy Report. California Energy Commission.

were analyzed under “slow”, “fast”, and “rapid” scenarios, in which key assumptions about declines in demand were made based on the CEC’s demand modeling. To remind the CEC of its earlier published work, we include graphs from the 2023 IEPR report and from the modeling data submitted as supplemental to the CARB 2022 Scoping Plan Update. [6]

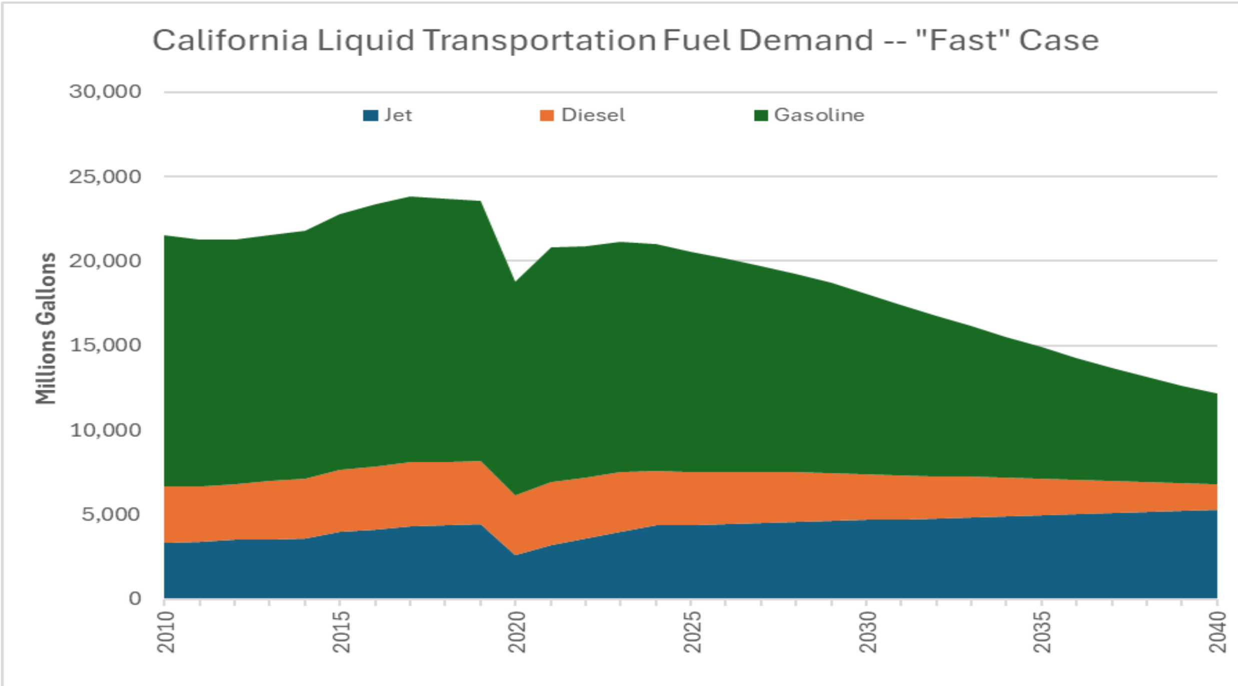
Figure 1 - CA Liquid Transportation Fuel Demand - "Slow Case"



Publication Number: CEC-100-2023-001-CMF.

[6] 2023 Statewide Fuel Demand Forecast - CA Energy Planning | California Energy Commission, last accessed May 14, 2024 at https://www.energy.ca.gov/media/9574. And from the Scoping Plan: 2022-sp-PATHWAYS-data-E3.xlsx (live.com). Note: We concur with CEC’s aviation fuel assumption that it has the same demand profile as the IEPR baseline case.

Figure 2 - "Fast" = 2023 IEPR AATE3 Case



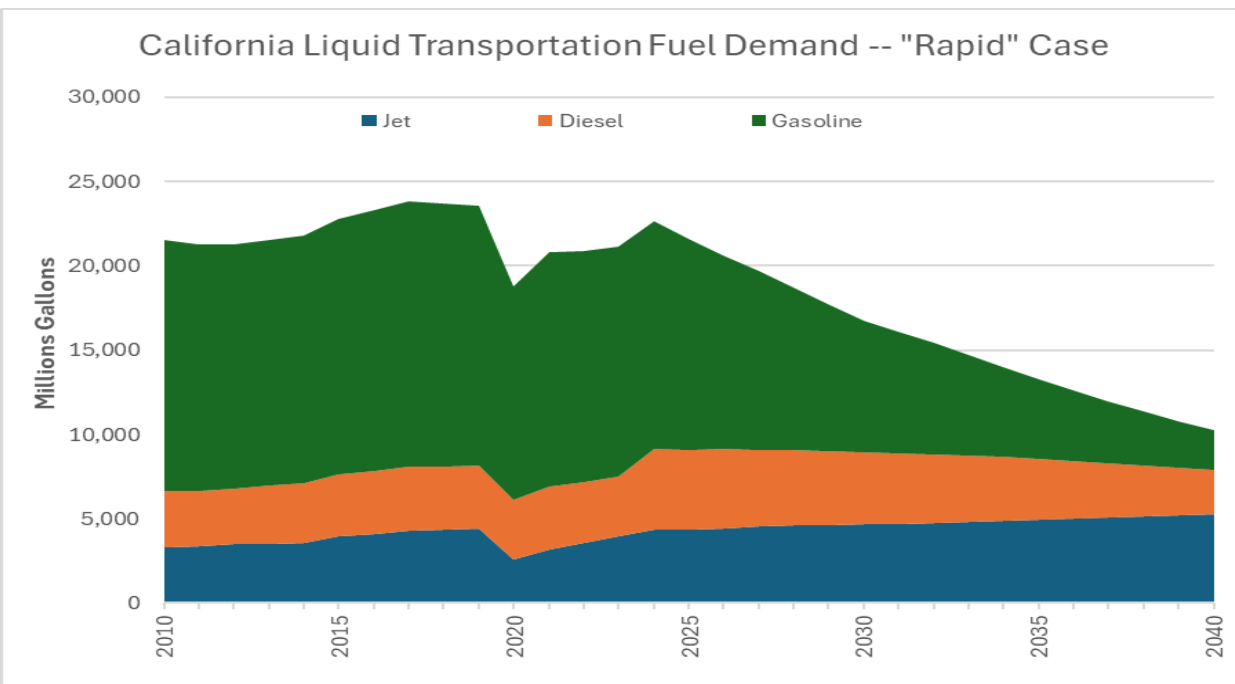


Figure 3 - "Rapid" = 2022 CARB Scoping Plan

The Draft is explicitly meant to underpin the CEC's and CARB's obligation under SB X1-2 to formulate a Transportation Fuels Transition Plan encompassing California's full range of transportation fuels and potential future demand scenarios for each. However, this Draft presents just one preferred scenario (i.e., varying degrees of sustained declining gasoline demand) rather than evaluating other possible scenarios. The scenario in this Draft implicitly assumes that everything works as planned in terms of policy implementation and required investments. That is not a proper transportation fuels assessment that leaves the State agencies prepared to develop a robust transition plan and strategy for the transportation sector.

An assessment evaluating the status of the value chain of all transportation fuels as described above (and required by statute) would provide the State agencies with a range of fuel scenarios, which would enable them to develop a more robust transition plan. There are several potential demand pathways the various fuel supply chains could follow in the future, and not all of them involve perfect implementation of the State's current policies. One cannot simply assume that gasoline demand will fall off precipitously (as do the three scenarios above), nor that the gasoline (or for that matter, diesel or jet fuel) supply chain will smoothly adapt to the CEC and CARB's predicted declining market. ***A more robust assessment would explore several "failure points" (e.g., meeting a significant reduction in Vehicle Miles Traveled) or places in the system that are lacking resilience (e.g., port infrastructure or electric grid build-out), and would model scenarios that take into account those potential failures***. The only vulnerabilities that are explored in this Draft are those related to the spot market and the vaguely defined potential for "manipulation", with several other key vulnerable elements left unexplored.

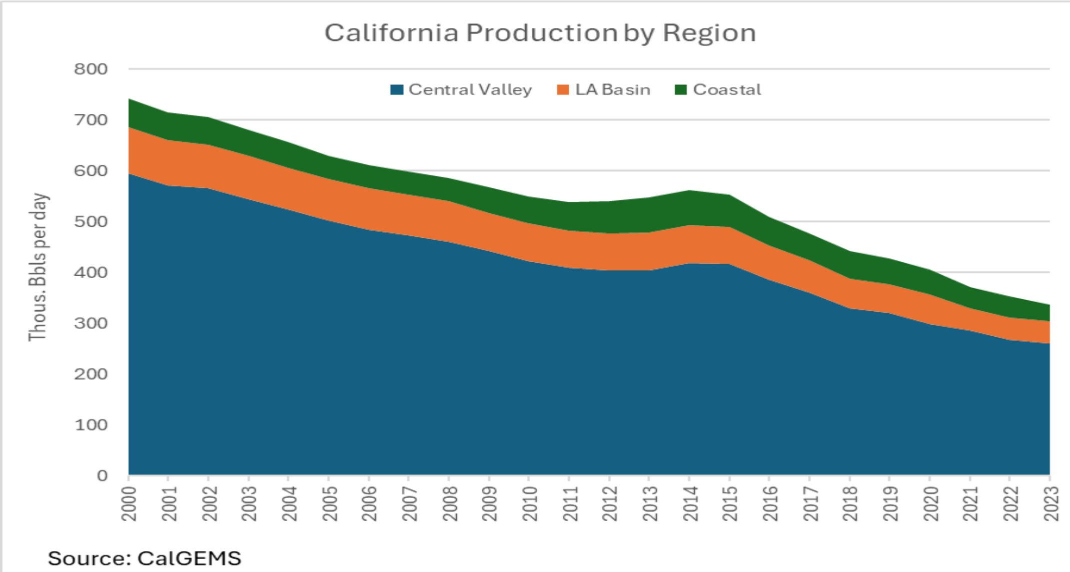
What is missing from the current Draft?

Crude Oil Production in California

SB X1-2 requires the first assessment to analyze the upstream (i.e., oil and gas extraction) and refining segments of the petroleum industry.[7] California has historically produced a substantial portion of the total amount of crude oil that is locally processed and refined in the State, predominantly for consumption in California, but also to meet supply obligations in other states and markets.

[7] PRC § 25371(a)(2)

Figure 4 - Crude Oil Produced in California by Region



California crude oil production has declined at an average annual rate of 3.4% since 2000. The decline rate has been accelerating and was close to 14% in the second half of 2023. The decline in California domestic crude oil production has more to do with difficulties in obtaining permits to drill than lack of oil reserves. As of December 2022, California held almost 1.5 billion barrels of proved and probable crude oil reserves, which ranked it sixth among the 50 states.[8] The observable decline in production is not due to resource availability or the "natural decline" in production often cited in State reports. The actual decline in domestic oil production is due to highly constraining policies and a permitting environment with increasing barriers to oil and gas production. This is a more aggressive decline rate than was modeled in CARB's 2022 Scoping Plan Update. [9] Constraints on domestic production have put substantial pressure on other parts of the system, including pipelines that transport crude oil to key refining locations in the State.

Producers and Permitting

WSPA does not see any evidence in the Draft that information about production conditions or constraints was sought from domestic producers of California's crude oil. This is worrisome given that SB X1-2 explicitly requires the State agencies to "consult with the state's fuel producers and refiners"[10] in preparing the Transportation Fuels Transition Plan, for which this Assessment is an

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[8] https://www.statista.com/statistics/790790/us-oil-reserves-by-state/.

[9] CARB 2022. 2022 Scoping Plan Update. pp. 101-5. While the 2022 Scoping Plan Update does not specifically "model" future declines in oil production, it assumes that production will decline at an average annual rate of approximately 2%, based on a UC Santa Barbara study commissioned by the State (https://zenodo.org/records/4707966). The 2022 Scoping Plan Update also notes that shifting domestic production volumes to marine imports may also have GHG leakage effects, and "could require more infrastructure to store and move larger volumes of crude oil to the refineries in state" (p. 104).

[10] SB X1-2, Section 25371.3.

essential foundation. Had the CEC and CARB sufficiently explored these key upstream parts of the fuel supply chain, they would have discovered what the industry knows quite well: California geographically has some of the largest and most accessible oil reserves in the world. California producers simply are not permitted to get to them due to State impediments.

It is well understood on the production side of the industry that development of reserves requires a program of continuous evaluation, investment, and development. It is almost never the case that a substantial reserve is developed in one phase and depleted through the first initial tranche of investment. Permits for drilling, whether for exploration or production, are an essential requirement of a properly functioning production sector. However, in the California case, new permits for drilling have been severely curtailed and many producers have been forced in the short term to rely on existing investments to be economically viable. This is only a short-term adaptive solution; extended denial of access to the resource means that operators must make hard decisions about the economic viability of their production enterprises.

Therefore, lack of new drilling permits is forcing producers to rely predominantly on existing permitted facilities to maintain production. To date, as of May 2024, the primary permitting agency responsible for production-oriented permitting, CalGEM, has approved only about 300 production-related permits.[11] Compared to "normal" periods of business, this level of performance is less than 20% of what producers in California have long recognized is needed to meet the requirements of a properly functioning permitting process required for production operations to in turn meet demand for crude oil in the state. A proper fuels assessment would go as far upstream as necessary to assess the availability of crude oil assets and the cost constraints on acquisition of the 1.4 million barrels per day required to supply the State's refinery processing demands.

[11] CalGEM approves more than 18 different types of permits for subsurface activities, including injection wells, monitoring wells, testing wells, and other wells related to the overall operations of a producer. However, only five types directly relate to production of crude oil: new drills, reworks, sidetracks, well stimulation (fracking), and deepening. These five permit types have been stalled out at CalGEM since the Newsom administration began giving direction to CalGEM in 2019 to limit or halt the approval of permits for all manner of production activities, including well stimulation and high-pressure cycling steaming. Not only has permit approval declined precipitously, but the average time between submission and approval has increased over seven-fold in the five years since 2019. (Source: WSPA analysis submitted to CalGEM through various regulatory processes).

Figure 5 - CalGEM Oil and Gas Permits 2011-2024[12]

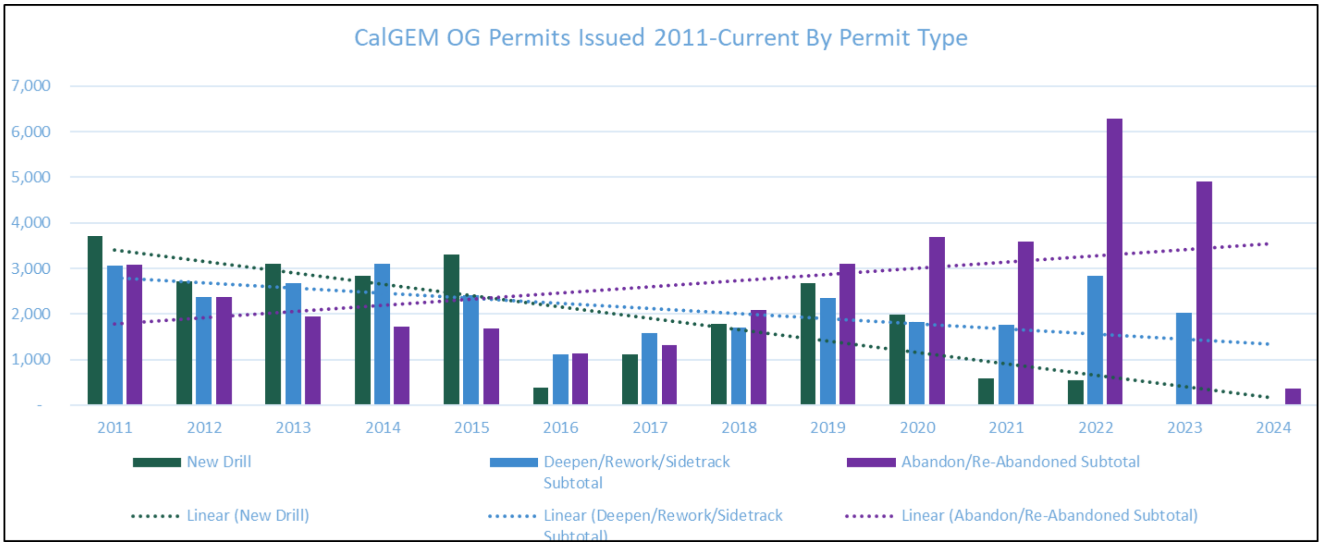
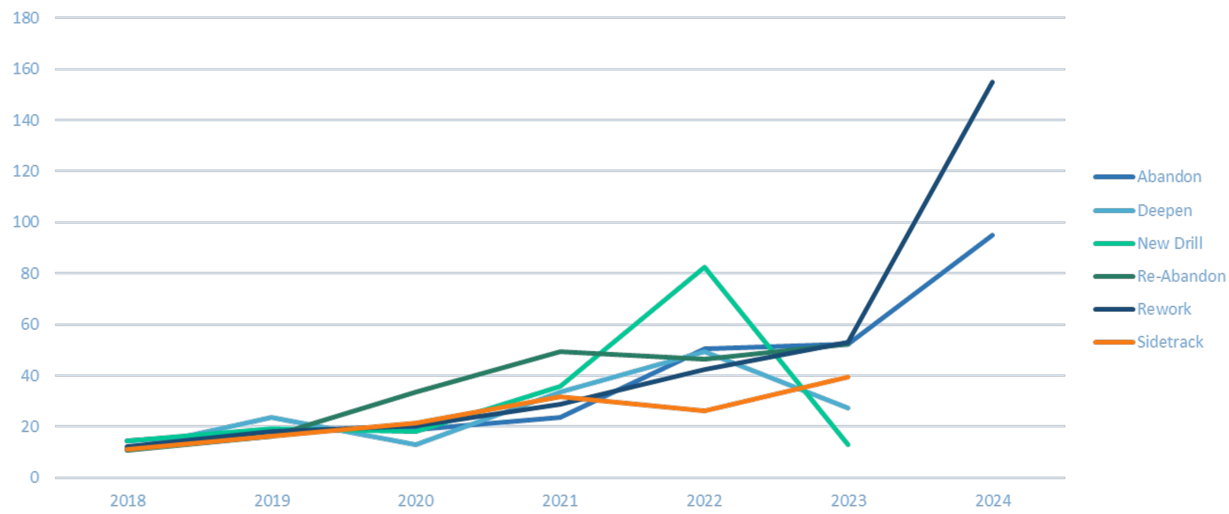


Figure 5 shows the decline in production-related permits approved since 2011. Historically, the agency has approved an average of 8,000-10,000 permits each year. Since 2019, the number of production-related permits has dropped to insignificance. The shift from production-related permitting to plugging and abandonment permits is dramatic, beginning with the upturn in global oil prices in 2017-18 and the increasingly politicized focus on shutting down and shutting-in production in California.

As a further impediment, the time that CalGEM takes to approve a production-related permit has expanded by over seven times in a mere five years, from an average of about 12 days to more than 185 days (see Figure 6, below). These are conditions that severely impact production in the state and explain a great deal of the decline in crude oil volume produced domestically.

[12] CalGEM WellSTAR data; Catalyst Environmental Solutions analysis, *unpub. reports.*

Figure 6 - Time to permit approval of oil and gas permits at CalGEM



Crude Oil Pipeline Capacities

As the Draft notes, "Kinder Morgan operates the only common carrier pipeline network within California."[13] However, the Draft only discusses the pipelines carrying refined product. Crude oil pipelines are a major component of California's domestic refining supply and are not even mentioned in the Draft.

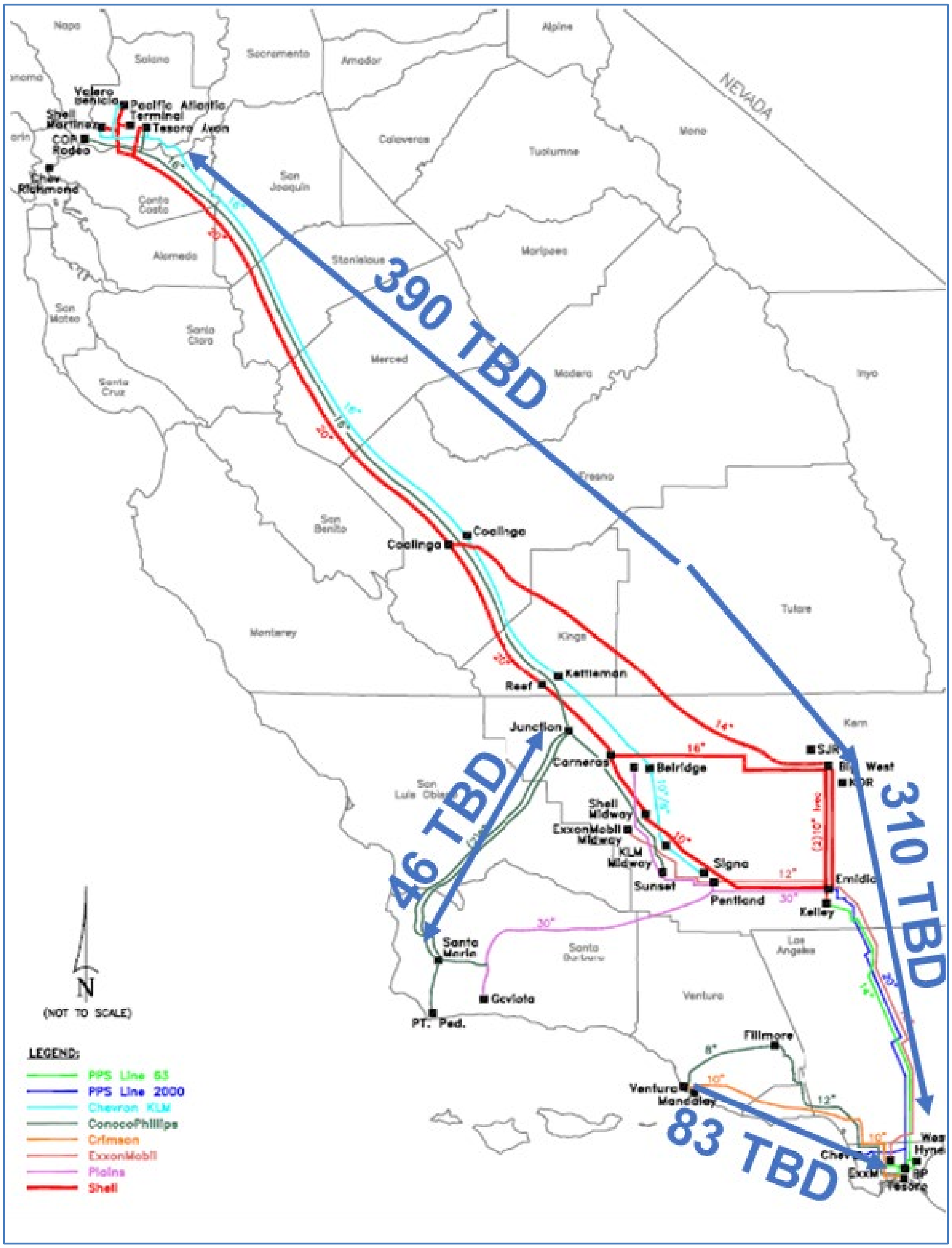
Pipeline entities play a key role in the supply chain that is critical to moving crude oil from domestic sources to the two regions (Los Angeles basin and San Francisco Bay Area) where domestic crude oil supply is essential to refinery performance. Were the CEC and/or CARB to have consulted the operators of these pipelines, they would have learned that this part of the supply chain is running at critically low volumes.

Figure 7 shows the alignment of several critical pipelines for crude oil and indicates their current design capacities. These design capacities were engineered with long-term production in view and took into account the reserves and likely future demand for transportation from oil fields to refineries dating from the 1980s onward.[14]

[13] Draft, P. 31

[14] Sources: Analysis of key company and government public websites. Turner Mason & Company, *unpub. analysis.*

Figure 7 - Location, alignment and carrying capacity of key crude oil pipeline infrastructure



Each crude oil producing area is connected to a given refining center by multiple pipelines of various diameters (capacities). While this can be good for redundancy, in the event of an interruption, it also creates challenges in keeping the system operational as local oil production continues to decline. A pipeline must maintain some minimum volume so the crude oil will continue to move. This minimum throughput volume is a function of the pipeline's design (e.g., diameter, length), operating conditions (e.g., pressure, temperature), geography (e.g., elevation changes), the age of the pipeline, the regulatory environment, and the characteristics of the crude oil itself (e.g., gravity, viscosity). The vast majority of crude oil produced in California, and in the San Joaquin Valley in particular, is heavy oil (high specific gravity) and therefore requires lift and heating specifications to move the crude oil over long distances.

It is critical to understand that California's crude oil pipeline infrastructure was designed to support decades of growing demand, both in California and the other western states. They are also key elements of the national security infrastructure on the west coast, supporting strategic U.S. interests in the Pacific.

Marine Terminal Throughput Capacity

The Draft, and indeed much of the California policy direction on fuel supplies, appears to assume that reductions in domestic crude oil production can be easily compensated for by increasing imports of both crude oil and refined products. ***However, the Draft fails to adequately address the actual throughput capacity of the marine terminals that are assumed to be required by this substantial increase in imports, and also fails to address regulatory constraints that CARB has imposed on tanker vessel calls at California ports starting in 2025.*** We further elaborate on some of the impacts of the Ocean-Going At-Berth Regulation (At-Berth Regulation) in greater detail below.

Further, an adequate assessment of the realities of refining crude oil in the State, along with a proper assessment of the displacement of Ultra-Low Sulfur Diesel (ULSD) with Renewable Diesel (RD), would clearly show that the same marine terminals that the CEC and CARB assume will accommodate transfers of millions of barrels of refined fuel will already be busy hosting ever-increasing volumes of imported crude oil from foreign countries.

This Draft does not present a realistic assessment of these factors, nor does it examine the critical pinch point in the system that marine terminals represent, which could have major impacts on supplies and prices. The CEC and CARB must assess marine terminal constraints if they are to determine if or how additional refined fuel volume flows will be accommodated by existing marine terminals. There are four incremental marine terminal throughput flows that should be properly analyzed, critically including a sharp eye toward impacts of constraining policies such as the At-Berth Regulation:

1. Additional crude oil receipts to compensate for the continued and accelerated decline of in-state oil production.
2. ULSD export volume increases as a consequence of increasing RD use in California. This also includes RD movements from Northern CA and other domestic and international renewable fuels facilities into Southern CA (i.e., the Ports of Los Angeles and Long Beach).
3. Growth in biorefinery feedstock receipts to supply renewable diesel and sustainable aviation production facilities – other than rail imports that supply biofuel feedstocks directly to those biorefineries.
4. Changes in product flows associated with the likely closure of a refinery – such as the need to import gasoline and other refined products to maintain contractual supply obligations if a refiner elects to transition the facility to a fuel terminal.

Other Marine Logistical Constraints

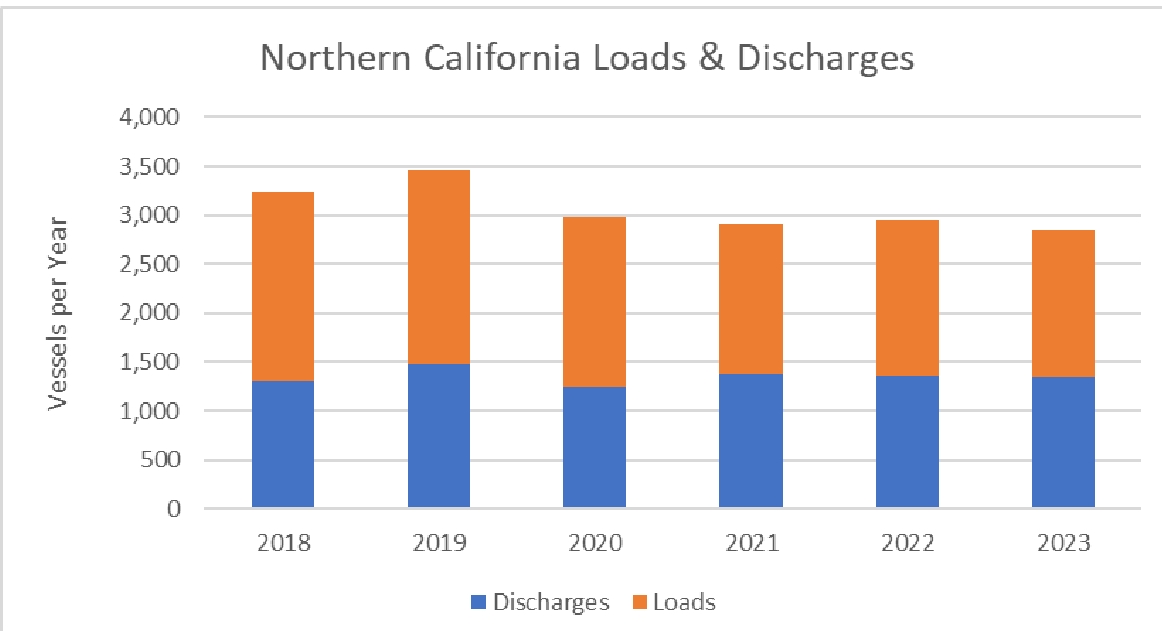
Vessel Traffic

The State Lands Commission (SLC) collects data on vessel movements (both barge and ship) for each marine facility in California. The CEC and CARB can analyze these data to assess how trends in California crude oil production and transportation fuel demand are impacting ship traffic.[15] Under its recently adopted emergency regulation,[16] the CEC will now be collecting this data as well. For example, Figure 8 below shows total vessel movements for loads (outbound) or discharges (inbound) cargoes in the North (greater San Francisco Bay Area).

A vessel "load" occurs when petroleum products are transferred from onshore storage tanks to compartments aboard the product tanker or barge. Some of these transfers can include multiple types of refined products or feedstocks segregated by compartments. Loaded vessels will then depart a marine terminal as an export (to foreign destinations or the Pacific Northwest) or intrastate movement to another California terminal.

A vessel "discharge" occurs when a petroleum product or refinery feedstock is transferred from the marine vessel to onshore tankage. The vessel's cargo may have originated from outside the state, another California marine terminal, or in some cases from a ship-to-ship transfer. Details are contained in the SLC datasets (e.g., if the vessel is a barge or ship and whether the ship is an international or Jones Act tanker). Since 2018, there has been a decline in the number of loads, but the number of discharges has remained fairly constant.

Figure 8 - Northern California Loads and Discharges (Vessels per Year)



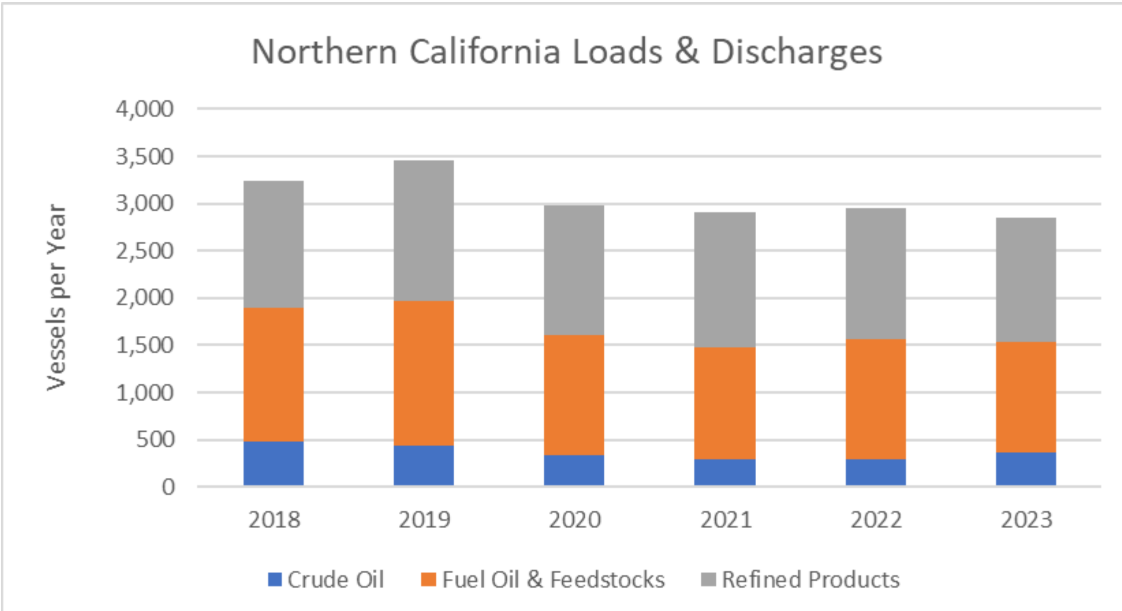
These data can also show what materials are moving across the docks. Figure 9 shows vessel movements in the North (i.e., San Francisco Bay Area) for crude oil, fuel oil and feedstocks, and refined products that consist of traditional transportation fuels (gasoline, diesel. and jet fuel) and

[15] California State Lands Commission and Turner Mason & Company analysis, 2024.

[16] Docket No. 23-OIR-03 under Resolution No. 24-0508-07, "General Rulemaking Proceeding for Developing Regulations, Guidelines, and Policies for Implementing SB X1-2 and SB 1322."

renewable fuels (renewable diesel and sustainable aviation fuel).

Figure 9 - Northern California Loads and Discharges – Crudes, Fuels and Oil Feedstocks, & Refined Products



Most of the recent decline in loadings seen in Figure 8 has been fuel oil ships seen in Figure 9. What these data do not show are potential constraints to the marine logistics system. Those constraints can come in two forms: available dock space and regulatory constraints of the At-Berth Regulation, both of which we discuss below.

Dock space

Refineries have limited berths (some have only one) and can be limited by the length of the ship or its draft.[17] The growth in containerized freight imports in the Ports of Los Angeles and Long Beach impacts the traffic patterns within the port and creates constraints on tanker movements within the port. All of these factors make the scheduling of ship traffic critical and increasingly more difficult as vessel traffic grows. The CEC and CARB should analyze the capacity for energy-related vessel traffic in ports in both the North and South in order to fully test its hypothesis that more vessels and port capacity can be made available to replace California's domestically produced crude oil.

- Regulations limiting the number of vessel calls and ships at dock.
- Another limitation to vessel traffic is whether the tanker originated from a domestic port, which requires it to be a Jones Act-flagged tanker. There are only 55 of these U.S.-flagged vessels and eight of them are dedicated to moving renewable diesel from the Gulf Coast to California.[18] The market for Jones Act ships is extremely tight, especially for spot charters.[19] Spot charter availability is critical to the CEC's transportation fuels assessment because it is the charter class used if ships need to be quickly contracted in the event of a

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[17] Draft is the distance from the waterline to the bottom or keel of the ship.

[18] [Survey: Jones Act rates get renewable diesel boost | Latest Market News (argusmedia.com)]

[19] A "spot charter" is a shipping industry term for one-off or short term duration shipping contracts. See, for example, https://www.scorpiotankers.com/glossary_/spot-charter/. Last Accessed: May 16, 2024.

supply outage in California.

At-Berth Regulation

CARB's At-Berth Regulation will impose new requirements on marine terminal operations. It requires operators to reduce emissions from crude oil and product tankers by capturing stack emissions or by electrification of the marine vessel discharge operations by the use of shore-based power. Absent the ability to implement one of these options, most California tankers will be severely limited in the number of visits they will be legally permitted to make to California ports and marine terminals. At this time, the vast majority of the California tanker fleet, and the California ports and terminals that serve them, are not equipped to utilize shore power. Moreover, no stack emissions capture system has yet been developed, tested, or approved for use by tankers, and vendors will not be ready to provide such a system for many years to come.

WSPA submitted comments to the CEC on 4/25/2024 indicating our concerns about the impacts of implementing the new At-Berth regulations.[20] In that letter, we indicated that "CEC should take note that the California Air Resources Board's (CARB) recent amendments to the Ocean-Going Vessels At-Berth Regulation (At-Berth Regulation) will serve to further constrain refined products, renewable fuels, and crude oil supply into California. By requiring petroleum tankers to use emissions capture or shore power technology not yet developed, tested, or implemented on the vast majority of California's tanker fleet or tanker terminals, CARB's At-Berth Regulation will force many tankers to reduce visits to California ports starting in 2025 to meet the At-Berth Regulation's requirements. This is another example of a State policy that will further restrict the availability of gasoline in the State of California and will limit the State's ability to mitigate in-state shortages of gasoline supply with marine imports. And it is another policy that will likely hurt California consumers rather than helping them."

Given these concerns, we would urge the CEC and CARB to consider the following issues as the agencies seek to harmonize any future policy proposals with existing regulations that are already in place and will have near-future impacts that may conflict or exacerbate new or proposed policies.

- Marine terminal operators (refiners and port authorities) are unable to provide an accurate critical-path compliance schedule for the At-Berth Regulation, due to the inadequate number of commercially viable vendors of barge-mounted emission capture technologies that could be potentially modified and approved for use for the California tanker fleet.
- Similarly, shore power is unavailable for the vast majority of the California tanker fleet, as most tankers, ports, and terminals do not have appropriate shore power infrastructure for tanker use. Even if that hurdle could be overcome, the State grid currently lacks the electrical generation, transmission, and distribution capacity to electrify all vessels and terminals covered by the At-Berth Regulation.
- These realities put at risk the obligated parties' ability to comply with the At-Berth Regulation's deadline of January 1, 2025 for vessels visiting the Ports of Los Angeles and

[20] https://ww2.arb.ca.gov/our-work/programs/ocean-going-vessels-berth-regulation; WSPA comments may be found at https://content.govdelivery.com/accounts/CNRA/bulletins/398c8a0, Docket 23-OIIP-01, Western States Petroleum Association Comments - WSPA Comments on April 11 SB X1-2 Margin Cap and Penalty

Long Beach, and further unlikely to be able to meet the January 1, 2027 compliance deadline for vessels visiting any other California marine terminal.

- Absent an extension of the current compliance deadline schedule, there is a risk that some marine terminal operators will have to significantly reduce the number of product tanker port calls to reach the exemption level of 20 per year until the required control technology is developed and implemented.
- This complex of challenges will create yet another constraint on refineries' marine throughput capacity for crude oil and products.

A Potentially Critical Scenario

According to CalGEM, California's domestic crude oil production averaged 338 Thousand Barrels per Day (TBD) in 2023.The U.S. Energy Information Administration (EIA) estimates that production fell to 293 TBD by February 2024. Meanwhile, California refiners processed an average of about 1,430 TBD of crude oil during 2023. Thus, in-state production in 2023 accounted for 25 percent of California's total crude oil feedstock needs.[21] However, the recent continued decline for the month of February 2024 means that in-state oil production represented approximately 20% of California's total refining needs. California in-state oil production has been declining at an overall average annual rate of about 10% since 2015, but it is important to note that this rate of decline has been *accelerating*. Measured over the last *four* years, the average annual drop in production has been about 14%. No matter how the rate of decline is measured, it is still far steeper than any of the CEC or CARB planning and strategy documents project. For example, as mentioned above, the 2022 CARB Scoping Plan Update projects that annual California domestic oil production will decline at a gradual rate of approximately 2% per year, consistent with their demand projections. Clearly, reality has gone beyond the modeling and must be accounted for.

This higher-than-predicted rate of decline in California oil production is challenging some pipelines to maintain minimum flow rates. As mentioned earlier, pipelines must maintain some minimum throughput to remain commercially and operationally viable. When a pipeline is forced to close, the production it carried must find another pipeline, or another mode of transportation, such as rail or truck. The alternative is to cease production altogether in the oil fields that require pipelines to move crude oil to refineries. The Central Valley has multiple pipelines running north and south. While each corridor has a number of trunk pipeline options and destinations, declining production makes it difficult to keep all lines at minimum throughput. The risk of closure could be higher for northbound lines leaving the Central Valley because these pipelines tend to have larger capacity and must negotiate undulating terrain, with intermittent pump stations to boost flow.

The decline in California crude oil production is a challenge for California refiners as well. California crude oil has fallen to 25% of refinery crude oil supply, down from 50% in 2000, and 62% in the 1980s. In the future, if a pipeline shuts down and a refinery cannot find an alternative pipeline for California crude oil, it must source crude oil by another means, such as rail or ship. No California refineries have crude oil unit train[22] transfer facilities, so they must rely on marine infrastructure to replace diminishing availability of California crude oil. Replacing California crude oil with waterborne sources increases vessel traffic, ship channel congestion, and emissions – and

[21] https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPCA2&f=M

[22] A unit train for crude oil consists of about 100 cars containing about 70k barrels of crude oil.

presents regulatory challenges, as discussed above.

Some refineries have limited access to marine facilities. If a refinery has only one berth, the refinery must choose between bringing in crude oil, refined product blendstocks, or finished products. They must also consider potentially exporting other products. For example, a refiner may need to increase waterborne crude oil imports and exports of fossil-based diesel (displaced by renewable diesel) and would face increasingly constrained marine terminal throughput with limited dock capacity. A refinery in such a scenario would be faced with serious decisions about whether to remain in business in California.

Depending on the size of the dock, onshore tank capacity, and pumping rates, it can take two to three days to unload a ship. Some refiners could only receive or load 10 to 15 vessels per month for all crude oil and refined product volumes. Based on an average refinery and average crude oil tanker delivering to California, this would not be enough crude oil to keep the refinery viable.

If a refinery were to convert to a product terminal, it would increase vessel traffic by 3 to 5 times to supply the market with same volume of product because clean product tankers are much smaller than typical crude oil tankers. In other words, it takes more time, investment, and space to replace crude oil imports with refined products.

Policy Options Presented in the Draft

WSPA appreciates that the CEC and CARB are trying to be as creative as possible in presenting policy options to mitigate fuel supply shortages. However, we believe that only some of the policy options presented in the Draft warrant serious further consideration, analysis, and development. WSPA also believes that each of the viable policy options not only deserves to be developed in detail, but that the CEC and CARB need to invest heavily in both public input and qualified industry expertise in order to vet them thoroughly and explore the potential unintended consequences on the fuel supply, as well as other potential effects of these policies on other sectors of the economy, and on California's consumers.

WSPA is aware that the CEC and CARB engaged other industry experts in developing the Draft. WSPA has also worked extensively with many of those experts and their organizations in the past, and we are fully aware of their capabilities. We do not believe that the current version of the Draft reflects the full suite of the capabilities of those experts, whose known expertise spans the entirety of the supply chain, from production to logistics, to refining, and to marketing and distribution.

For this reason, WSPA has engaged the expertise of Turner Mason & Company (TM&C) to perform detailed analyses of several elements of the supply chain. Seeing that the Draft clearly did not present analyses of the full range of transportation fuel supply scenarios, as we have observed above, our work with TM&C has examined a number of areas of vulnerability and risk in the supply chain. WSPA would be pleased to have an opportunity to engage in a meaningful collaboration with the CEC and CARB to share our expertise, as well as the findings of our industry experts.

WSPA further encourages the CEC and CARB to workshop key options for subsectors of the supply chain, to more completely understand the dynamics, business models, and capacities of the supply chain in more detail than was demonstrated in the Draft. For example, should the CEC and CARB wish to examine the effects of marine terminal complexities and limitations on imports and exports more carefully, we would hope that the agencies would use their convening power and resources to engage port facility managers, shippers, vessel leasing experts, and dock-to-refinery system managers to learn from their perspectives.

We would also encourage the CEC to convene a public hearing asking CARB to explain why it has chosen to significantly restrict tanker visits to California ports and terminals at a time of great need for the state, rather than considering amendments to the At-Berth Regulation to allow those visits to occur until emissions control technology is developed and implemented throughout the tanker fleet. Further, should the agencies wish to more fully understand the factors that go into spot market trading decisions, perhaps the CEC would be willing to engage with actual traders to gain some knowledge about their decision-making processes.

While we appreciate that the CEC and CARB have described 12 potential policy pathways in brief form, with pros and cons, decisions of such gravity and consequence cannot be made based on a few mere paragraphs and tables. Other similarly significant changes in California's energy policies have involved multiple studies and extensive analyses by experts that have taken months, if not years, of meaningful deliberations and consultation to explore, develop and implement. We firmly believe that the Transportation Fuels Assessment and the Transportation Fuels Transition Study proposals envisioned by SB X1-2 warrant at least the same level of engagement, analysis, development, and vetting before significant and consequential decisions are taken by State policymakers that could hurt Californians more than help them. These are decisions that could easily put the entire fuel supply chain at risk, not only for the State of California, but for our two neighboring states of Nevada and Arizona, whose fuel supplies are firmly dependent on the viability of California's petroleum supply chain and most notably, California's refiners.[23]

Finally, the CEC has the resources and authorities under the Petroleum Industry Information Reporting Act of 1980 (PIIRA) and SB X1-2 to learn from the industry through the request for and analysis of confidential business information. This is the kind of information that WSPA and other entities are not allowed to either know or share, due to important antitrust protections. However, given the level of understanding of the industry revealed through the Draft, WSPA would strongly encourage the CEC to meet with individual companies under PIIRA protection and ask key questions in order to learn whether many of the assumptions the CEC and CARB have apparently based their Draft on have any substance or reality. For example, the presumption (perhaps based on an economic theory) that refiners have much more excess capacity, either in utilization percentages or storage, should be tested with each company rather than simply asserted as a public conclusion without sufficient evidence. Or, as another example, that the CEC appears to assume that refiners can be compelled to increase reserve capacities in order to mitigate supply shortages during planned and unplanned outages of refinery operations. However, without actual knowledge or evidence, or an analysis of the time or logistical steps this would require (including local permitting), this assumption cannot be tested as a viable policy option.

In the following sections, we comment on the policy options presented in the Draft that we believe warrant further development. WSPA believes that the policy options we are choosing <u>not</u> to comment on simply do not have any realistic place in the array of policy choices the agencies have before them, nor do they warrant serious further consideration or staff time. We suggest that these ideas be moved to an appendix in the final version of the Assessment to document that they were considered. However, we do not believe they warrant further time, energy, or resources from state agencies.

[23] According to the CEC, California's refineries provide most of Nevada's and nearly half of Arizona's transportation fuels. https://www.energy.ca.gov/data-reports/energy-insights/what-drives-californias-gasoline-prices. *Last accessed: May 16, 2024.*

Cost of Service (COS) Policy Option

We are addressing the COS model only because it has received so much attention by public members at CEC workshops and during recent State Legislature oversight hearings. We have very serious concerns about the viability of this model as it could be applied to a global multi-commodity market, such as petroleum, which is not a natural monopoly and has not traditionally been regulated in the United States as a utility.

A utility-based COS model for electricity and natural gas distribution is a regulatory oversight and control structure intended to address natural monopolies that provide a single type of energy commodity to customers in a specific geographic marketplace. Price controls and cost recovery for operating expenses and capital improvements at a profitable return-on-investment are primary elements of a utility model.

Such an approach does not easily lend itself to the transportation fuels market, which is neither a natural monopoly nor a single energy commodity. Exactly how a cost-of-service model could be applied to California refiners' operations and the other transportation fuel value chain segments (i.e., upstream producers and pipelines, storage providers, marine infrastructure, downstream distribution infrastructure, wholesalers, and retailers) has not been explained in the Draft. More concerning, the Draft does not discuss the potential benefits to consumers of a COS model, nor does it address the potentially deleterious unintended consequences associated with an inadequate fuel supply in that model. If the State were to continue to pursue such a policy option, we would strongly urge the agencies to develop a report that, at minimum, addresses the following critical questions:

- How would the California Public Utilities Commission (CPUC) regulate the prices of all output from refiners ranging from liquified petroleum gases (butane and propane), to refined products (gasoline, diesel, jet fuels), to other products (residual fuels, fuel oils, lubricants, asphalt, plastics, and petroleum coke)?
- If this policy were only intended to be applied to gasoline sold in California, how would a cost-of-service model be applied to only a single commodity for firms producing scores of other petroleum-based commodities? How would cost recovery be apportioned just to California gasoline output?
- How would the CPUC regulate all, some, or none of the domestic and international refinery feedstocks such as crude oil and gas oils?
- How would the CPUC regulate the other costs incurred by the refiners for operating expenses and necessary capital investments for planned refinery maintenance, unplanned outages, and compliance with myriad local state and federal regulations involving fuel regulations and emission limits?
- How would the CPUC regulate the cost of marine logistical services associated with imports, export, and intrastate movements of refinery feedstocks, refined products, and renewable fuels? We would ask the same question about truck transport services.
- If other refined products and refinery feedstock prices are regulated, how would the CPUC compel foreign suppliers to sell to California refiners at set price levels? Would the Federal Energy Regulatory Commission (FERC) or the U.S. State Department have authority to set these prices? Would the State cover the incremental costs refiners incur above the set values for imported crude oil, other refinery feedstocks, and refined products?
- How often, under what circumstances, and by what adjudicated process would the CPUC revise commodity prices?

- How would other prices be controlled downstream of the refiners by the CPUC to ensure that other market participants such as wholesalers and retailers would not take advantage of set price levels by increasing their margins to end-use customers? Does that mean the CPUC would set prices at all distribution terminal racks, and the 10,000-plus retail station outlets?
- How would the CPUC's role at the State level interface with the Commodity Futures Trading Commission (CFTC) role at the Federal level?
- How would a COS model for the California fuel supply chain affect contractual obligations that refiners currently have with other states, such as Arizona and Nevada? Does this require addressing legal issues, such as the commerce clause or other federal preemption questions?
- How does a COS model avoid or mitigate a loss of supply due to an unplanned outage?

Policy Options WSPA Recommends for More Complete Treatment

Recognizing that the CEC and CARB have already acknowledged California's structural fuel supply barriers as a key element in contributing to price spikes, WSPA recommends that the agencies invest additional energy and resources into any of the policy options that have the potential to increase inventory and stabilize in-state fuel supplies. We would discourage the agencies from spending further resources on the other policy options, as further development would only increase risk and potentially exacerbate the current policy impacts that are constraining local fuel supply. If the agencies feel obligated to keep all options open in their final Transportation Fuels Assessment, we recommend placing the remaining options in appendices that demonstrate that the agencies creatively considered even the most implausible options.

We do not discuss the demand-oriented policy options presented in the Draft because we feel that these kinds of programs are already under sufficiently robust development through CARB and the CEC, and reflect the State's other policies designed to reduce consumer demand. We only note, as mentioned above, that predictions or forecasts about future fuel demand in California must account for and compare scenarios beyond the State's preferred declining gasoline demand scenario. We further urge the agencies to avoid unrealistic expectations that lower income Californians will somehow be able or willing to transition to more expensive electric vehicles on the schedule the State prefers, rather than the schedule these consumers are able to accommodate financially.

The Draft offered brief descriptions of three inventory-related policy concepts that merit additional analysis and public discussion: a Strategic Fuels Reserve, Minimum Inventory Levels, and E15 Blending. We address each of these briefly below.

Strategic Fuel Reserve

The CEC previously studied the concept of creating a Strategic Fuels Reserve (SFR) in 2000 and 2001, at the direction of Assembly Bill 2076.[24] The purpose of the SFR concept was to reduce the magnitude and duration of fuel price spikes in California. Given the analogous situation cited in SB

[24] Assembly Bill No. 2076, Shelley, Chapter 936, Statutes of 2000, State of California, approved by the Governor September 29, 2000. Link: http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_2051-2100/ab_2076_bill_20000930_chaptered.pdf]

X1-2, and the mandate to the CEC to explore all options, we recommend the agencies direct due attention to the work previously done.

During that process in 2000, the CEC assessed the concept of a strategic fuels reserve using a combination of consultant and internal technical staff resources. A revised consultant report was published in July 2002.[25] Over the following year, the CEC held workshops and conducted a hearing that concluded that "…the Governor and Legislature should not proceed with the strategic fuel reserve concept evaluated by the Commission. The Commission found that a strategic fuel reserve could have several unintended consequences, which could limit its effectiveness as a tool to moderate gasoline price spikes and could reduce the total supply of gasoline in the state. In addition, the Commission has determined that investment in private storage capacity is increasing, which reduces the need for SFR public storage."[26]

The transportation fuels supply chain has continued to evolve since that initial assessment of an SFR concept, which merits a re-examination of this potential strategy to:

- Quantify the State's inventory capacity at both refinery locations and third-party facilities.
- Identify changes in storage capacity and types (leased versus community storage).
- Determine throughput limitations for marine terminals that could be used as part of the initial filling and subsequent restocking of the SFR.
- Reassess parameters of the original SFR concept to identify potential operational barriers or limitations to address price spikes, as well as potential negative consequences on private sector inventory holdings.

Minimum Inventory Levels

The other inventory-related policy concept identified in the Draft was related to a requirement for refiners to prevent their gasoline and component inventories from dropping below some yet-to-be-determined level, except under certain conditions. WSPA is concerned that such a concept could have unintended consequences for refinery operations, and constrain refiners' flexibility to meet changing market or operational conditions. If the CEC and CARB intend to pursue this course, we would urge the agencies to develop a report that would provide detailed responses to several critical questions about this concept, such as:

- How would the minimum inventory level be set?
- Would there be a different level for each refinery location?
- How would minimum inventories be managed through seasonal RVP transitions where inventory must be taken to minimum levels for tank turnover?

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[25] California Strategic Fuels Reserve, Revised Contractor Report, California Energy Commission, P600-02-017D, July 2002. Link: https://stillwaterassociates.com/wp-content/uploads/2023/03/Strategic-Fuel-Reserve-Study-Stillwater-Associates-7.3.02.pdf]

[26] Feasibility of a Strategic Fuels Reserve, Commission Report, California Energy Commission, P600-03-013CR, July 2003, page 2. Link: https://web.archive.org/web/20100607193136/https://www.energy.ca.gov/reports/2003-07-31_600-03-013.PDF]

- Would minimum inventory levels be extended to include third-party terminals?
- Does setting a minimum inventory level include increasing total storage capacity in the state for gasoline and blending components? How does the State anticipate incentivizing investment and potentially sharing risk?
- What are the feasibility studies and permit timelines for constructing additional storage capacity at refineries?
- If no additional storage tanks are constructed as part of this concept, do minimum inventory level requirements constrain refinery operational flexibility by effectively increasing storage tank “heels” and reducing “working storage capacity?”
- The CEC should better understand product allocations, which are essentially minimum inventory levels set to conserve supply, for example, during hurricane events in the Gulf Coast region.

E15 Blending

The CEC noted E15 as a production enhancement strategy to allow increase blending of ethanol from 10% (E10) to 15% (E15) to augment existing CARBOB supply. WSPA believes that such a change should not be mandated because it can be invoked during times of tight supply. Existing infrastructure for ethanol, and ship and rail offload capacity exist for short-term increased blend percentages. To allow for blending up to E15, CARB must update the Predictive Model that is used to certify CARBOB emissions. Under current modeling assumptions, E15 blends could potentially put the State Implementation Plan (SIP) at risk for being out of compliance.

Rail Supplies

The Draft listed a policy option concerning the capability to import transportation fuel by rail and transload to tanker trucks at various locations throughout the State. The CEC accurately characterized this potential policy as a strategy that could be deployed in response to a significant emergency, such as in the aftermath of a catastrophic earthquake. However, if the State were to develop such a capability, then transportation fuel market participants (refiners, importers, and large marketers) might take advantage of rail transloading infrastructure to bring in additional supplies of gasoline under certain market conditions. The agencies should conduct a detailed assessment that would include at minimum:

- Identification of existing rail transloading facilities for refined products, if any;
- Attributes required for a typical rail transloading site;
  - Rail siding;
  - Tanker truck access;
  - Transloading equipment;
  - Personnel;
  - Security;
  - Rail access agreements;
- Estimated range of investment required per site and rail transportation costs from specific domestic refining centers;
- Minimum number of locations and basis for making that determination;

- Timing for delivery from key points of domestic origin, compared to waterborne resupply; and
- Potential barriers to private sector operation related to rail car availability and availability out-of-state suppliers capable of producing CARB gasoline.

We also recommend that the agencies take care not to treat each of these options in isolation. Rather, once an assessment and analysis for each policy option has been completed, the agencies should examine whether market and fuel supply stability might be enhanced further by combining viable options into a more comprehensive suite of policy solutions.

Conclusion

WSPA appreciates the opportunity to comment on the Draft Transportation Fuels Assessment. We wish to reiterate that, while we believe this Draft is an important foundation to initiate serious public engagement, we firmly believe it is incomplete and not ready to become the basis of a comprehensive transportation fuels policy. Nor is it – in its current form – a sufficient foundation to underpin the Transportation Fuels Transition Plan mandated by SB X1-2.

Should the agencies wish to correct the deficiencies in the Draft that we have identified here, WSPA and its member companies are eagerly disposed to assist and collaborate in multiple venues to develop the information base and policy recommendations that one would expect any comprehensive strategic effort of this scope and gravity would require. WSPA has already invested heavily in analytical work on multiple subsectors of the entire fuel supply chain. We would be pleased to work with the agencies to share our information and analytical products. All of our analyses so far have been conducted using publicly available data (much of it published by the CEC and CARB themselves).

WSPA wishes to note that, throughout multiple hearings and workshops, CEC Commissioners have reiterated their commitment to full, good-faith engagement with industry to ensure the most comprehensive Transportation Fuels Assessment and Transportation Fuels Transition Study. This commitment, as we understand it, is not just to fulfill the Commission's specific obligations under SB X1-2. It is to ensure that the State and its citizens have reliable access to affordable, adequate, reliable, clean, and safe fuels from all sources for the energy needs of a thriving population and economy. We share that commitment, and we are ready and willing to work with the Air Resources Board and the Energy Commission to achieve those goals.

Sincerely,

Catherine Reheis-Boyd
President and CEO

CC: Liane Randolph, Chair, California Air Resources Board

WSPA

Catherine H. Reheis-Boyd
President and CEO

August 29, 2024

California Energy Commission
Docket Unit, MS-4 [Docket No. 23-SB-02]
715 P Street
Sacramento, California 95814

Uploaded to Docket

Preliminary WSPA Comments on Gasoline Supply Reliability Workshop [Docket #23-SB-02]

On behalf of the Western States Petroleum Association (WSPA), I am providing these initial comments on the California Energy Commission (CEC) and the Division of Petroleum Market Oversight's (DPMO) August 22, 2024, Senate Bill (SB) X1-2 (2023) gasoline supply reliability workshop. We are providing preliminary comments given the Governor's last-minute legislation (SB 950), proposed on August 27, that would allow the State to impose binding minimum gasoline supply inventory rules on industry.

At the August 22 workshop, DPMO staff stated that, "Governor Newsom has now proposed legislation that would give CEC this authority, and we are excited to support his proposal"[1] while simultaneously acknowledging that "we are still working to understand exactly what capacity we have available here in California."[2] The CEC then made it appear that industry had somehow helped shape the concepts, "…because industry really understands how to do this, these complex operations, and have been… doing this for decades to be able to kind of navigate the system" and "also recognizing industry, who are collaboratively working with us, and the ability to kind of do that."[3]

This is simply not true. The proposed legislation was not made available prior to its public release on August 27, and WSPA does not believe that industry was able to shape any such framework or the now pending SB 950 – upon which the authority to do so would be based. Rather, WSPA has repeatedly raised warnings that have gone unheeded. We hope the following information will help inform policymaking discussions in the State's attempt to micromanage California's gasoline inventory supplies – which **is a recipe to *raise everyday California fuel costs and potentially reduce fuel supplies to Arizona and Nevada, too – all while minimizing the existing safety-first priority***.

PROPOSALS COMPROMISE SAFE REFINERY TURNAROUNDS

The workshop proposal and SB 950 stray from industry's calls *to avoid compromising refinery safety at all costs*. Labor had raised similar concerns. Instead of fixing decades of poor policies that have driven supply down, these proposals hold industry's safety-first turnaround planning efforts hostage. SB 950 would give unlimited authority to an agency that lacks expertise in running a refinery, advised by a committee devoid of industry experts, to hold turnaround plans in response to price signals – not legally binding safety and compliance needs; this endangers workers and communities. There is nothing to prevent the CEC from interfering with any existing health and safety requirements, leaving refiners to manage profoundly conflicting regulations.

NO EVIDENCE SHOWN THAT MORE FUEL IN INVENTORY WOULD STOP PRICE SPIKES

- California's fuel supply chain already maintains substantial volumes of gasoline inventory. California has not come close to emptying its gasoline supplies; the lowest gasoline inventory recorded since 2011 was still over 425 million gallons (in 2023), representing over 12-days' worth of supply.
  - Mandatory stockpiles have been investigated by the CEC and shown to come with significant costs, which will likely and ultimately be borne by consumers.

[1] CEC August 22, 2024, Gasoline Supply Reliability Workshop at 46:29 mark: https://www.energy.ca.gov/event/workshop/2024-08/workshop-gasoline-supply-reliability
[2] CEC August 22, 2024, Gasoline Supply Reliability Workshop at 48:07 mark.
[3] CEC August 22, 2024, Gasoline Supply Reliability Workshop at 57:34 mark.

- Minimum inventory levels would most likely create sustained gasoline price increases due to new tankage and working capital costs and would not reduce price spikes.
- Gasoline that could be supplied to California, Arizona, and Nevada consumers might need to be kept off the market, creating shortages and inflating costs for drivers today.

- **Removes industry and labor voices from proposed Expert Advisory Committee.** Excluding CalOSHA and any recent industry consultants means the framework lacks any real-world expert advice and input.
- **Price volatility can happen regardless of how much gasoline is in inventory.** Massive additional storage cannot correct this problem due to permitting and operational cost constraints. What *could* help stabilize the imbalance is having sufficient local fuel manufacturing capacity, connectivity to other regional markets, and fewer policy restrictions on imports.
  - While having additional fuel inventories may be useful to address *energy security* concerns, it is not a *price-control* mechanism. Inventory safeguards against the possibility of running out of fuel until additional supplies arrive or local production resumes. The resupply market works because higher prices attract additional gasoline supplies to balance an undersupplied market.
  - Refiners may be forced to hold inventory back as they await State authorization.
  - Once the CEC establishes a "Days of Supply" threshold and mechanism to release inventory, market trading behavior may result to drive prices up in response to the lack of market liquidity.
  - No analysis has been done on whether a minimum inventory requirement may actually *decrease* domestic gasoline production given that available onsite storage is needed to efficiently balance blending, testing and certification, and marketing activities.
- **DPMO reference to international case studies is not representative of California's unique fuel market.** Any examples of policy successes in other regions do not necessarily account for California's unique and extraordinarily complex transportation fuel market.
  - California is a fuel island. This was acknowledged in the Transportation Fuels Assessment.[4]
    - California is geographically large and topographically complex
    - Neighboring state populations and economic centers are far from California's
    - There are few supply- or demand-side substitution opportunities
  - California has a unique regime of environmental policies
    - A minimum inventory requirement does not consider California's storage constraints
    - A minimum inventory requirement also ignores challenges with importing fuel from other regions, due to California's unique geography and existing policies (e.g., CARBOB blend requirements, Ocean Going At-Berth Regulation, disproportionate Federal Jones Act harms).
    - There are especially significant differences with Australia.[5] That nation – which depends on imports for *two-thirds* of their total production demand – provided approximately $1.8 billion in funding to keep their only two remaining refineries operational until 2027, provides funds for refinery upgrades, and makes certain production payments.
- **CEC and DPMO did not address unintended consequences of minimum inventories.** Further work must be done to determine if any such requirement is feasible in California.
  - What will be the costs to consumers and other unintended consequences?
  - Where is the transparency from CEC and DPMO on these economic costs?
  - Neither CEC nor DPMO appear to have any certainty to confirm that mandated thresholds will prevent price spikes in California's market as identified in the Transportation Fuels Assessment:

    "it may artificially create shortages in downstream markets"
    "[it] could increase average prices for refiners to maintain additional storage"
    "market equilibrium may likely emerge at a higher price level"
    "potential exists for the state to be criticized for requiring refiners to withhold fuel from the market"

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[4] CEC Transportation Fuels Assessment Report: https://www.energy.ca.gov/publications/2024/transportation-fuels-assessment-policy-options-reliable-supply-affordable-and
[5] See refining section at https://www.eia.gov/international/analysis/country/AUS

- No analysis has been done on how refiners would store increased supply or be able to increase imports under the criteria pollutant summer CARBOB blend, Ocean Going At-Berth Regulation, and Federal Jones Act constraints.
- No consideration has been given to the likely competitive advantage provided by a minimum inventory requirement to foreign importers over domestic refiners, or how such an advantage could be alleviated.
- Likewise, there are other, non-refiner inventory holders in the State, yet no consideration has been given to requiring a minimum inventory across *all* inventory holders in the State.
- Maintenance cannot be determined based on economic interests alone, and under no circumstances should such interests prevail over or otherwise compromise safety or environmental needs – needs that are more appropriately understood and addressed by CalOSHA, industry, and labor.

It is especially concerning that important policy decisions would be made with minimal, if any, acknowledgement and ownership about potential cost impacts to end consumers. With no economic impact accountability – and lack of transparency at the CEC and DPMO– there is no line item to show how this proposal could increase consumer costs. The CEC and DPMO have the means to hide costs under refiners' margin data and continue to blame issues on industry. California's regulatory framework and logistical constraints already make it the most expensive refining environment in the nation. Even more regulation will only disincentivize investments and increase operating hurdles. This could lead to more refinery shutdowns, supply reductions, and even higher prices. This is only compounded when SB 950 would impose penalties of up to $1 million per day. This is not a sign of being collaborative with the industry that produces fuel California demands. It is wholly punitive – not to mention unlawful.

Sincerely,

Catherine H. Reheis-Boyd
President and CEO

Catherine H. Reheis-Boyd
President and CEO

September 19, 2024

Mr. Tai Milder
Division of Petroleum Market Oversight, Director
1516 9th Street
Sacramento, CA 95814

WSPA RESPONSE TO THE DIVISION OF PETROLEUM MARKET OVERSIGHT'S (DPMO) SEPTEMBER 13, 2024, GASOLINE MARKET UPDATE AND CONSUMER ADVISORY

Dear Director Milder,

I am writing on behalf of the Western States Petroleum Association (WSPA) to address and correct assertions made in your September 13, 2024, letter to Governor Newsom, Assembly Speaker Rivas, and Senate pro tempore McGuire and in follow-on media briefing statements.

First, you claim that there is more than enough gasoline to meet California's fuel demand. But this is false. Years of State policies have discouraged investments and decreased refining capacity by reducing the number of in-state refineries available to produce California's unique gasoline blend. California had 30 refineries in the 1990's. Today we have nine. In fact, that was largely the *purpose* of these policies – to move California to different energy sources and to discourage the production and sale of gasoline. As a result, ***California lacks the very infrastructure it needs to meet ongoing gasoline demand***, and it must turn to out-of-state imports when supply is impacted by unplanned refinery outages. After the many refinery closures over many decades, there is no additional capacity to bring online. Additional policy burdens on the few remaining refiners would only exacerbate this situation by disincentivizing investments in existing refineries – which could force more frequent unit shutdowns, thereby limiting supply and driving up prices – or cause more refiners to leave the State.

Second, you state that California needs to require the industry to have more supply during the busy driving seasons to help slow a run-up in gasoline prices. This assertion ignores two key capacity constraints: 1) daily gasoline production by California refineries equals driver consumption, meaning all gasoline produced is needed to supply the market, as was explained by the California Energy Commission's (CEC) own consultants, ICF and Stillwater Associates, in recent workshops and hearings – that refiners already produce as much fuel as they can reliably and safely produce; and 2) even if the gasoline was available, there is a lack of tankage at refineries to store supply, and building new tanks is not a feasible solution given that it takes the better part of a decade to build just one tank (at a cost in the tens of millions of dollars each) due to California's myriad of environmental requirements, and its well-known elongated permitting timelines, and subsequent legal challenges. A new policy that offers no solutions to these issues will not help Californians and would likely continue to discourage investment, which would likely lead to less fuel production and higher prices.

Third, you asserted that refiners have more storage capacity and simply choose to store less gasoline in the summertime. What this fails to recognize is that refiners have more *production capacity in the wintertime* given the easier-to-produce winter RVP specification and the generally lower driving demand. It also fails to recognize that refineries have a finite amount of gasoline tanks, which are actively used and needed in the gasoline production process. Thus, the combination of summer RVP gasoline specifications and increased driving demand impact supply – not refiner production or storage. What the CEC and DPMO staff have repeatedly failed to understand is that the logistics system for California's fuel supply system is dynamic, constantly moving gasoline components to blend them into finished products that are required to be certified and then sent via pipelines to terminals where they are transported to gasoline stations to meet market demand. It is NOT a static system of expensive tanks containing finished products waiting to enter the market.

Fourth, you sought to discredit the influence of crude oil prices on rising gasoline prices, noting the stark price difference between California's retail prices and the rest of the nation. But, as you know, California faces unique supply challenges. We have previously explained that there are many variables, in addition to global oil prices, in play. These include supply and demand of global gasoline and blend components, which are necessary for California's unique fuel blend (i.e., as global inventories move, so does the cost to purchase, ship, and blend California's gasoline), and California's fundamentally constrained production capacity. California's fuel supply chain is now structurally short and subject to short-term volatility given that California is a "fuel island," with resupplies from Asia taking approximately 3-4 weeks to arrive in California.

Fifth, you have stated that California refiners may seek to sell gasoline at prices far exceeding any increase in their own input costs. However, you neglect to include the costs associated with obtaining imports. If the California gasoline spot market value becomes decoupled from the market value, crude oil and refined gasoline exporters may have reason to send their product elsewhere to ensure they can cover their production costs. And if California refiners are unable to recover their high operational costs, in this State, it may disincentivize them from investing here and potentially shift capital to other regions.

Lastly, you advised Californians to compare fuel prices. WSPA fully supports this. As an industry composed of private competitors, our retail members uniquely display prices on large, street-facing signs allowing consumers to make informed choices. Similarly, consumers should demand transparency from their representatives regarding the policies they support. The DPMO's proposed policies pose risks to gasoline supply without guaranteeing stable prices. We suggest that consumers contact their representatives to request an estimated cost per gallon of gasoline in California, seek more information on policy proposals, including minimum inventory bills, and inquire about regulations under consideration for amendments like the Advanced Clean Cars II Regulation, the Low Carbon Fuel Standard, and the Cap-and-Trade program.

I hope this information is helpful in your ongoing efforts to better understand California's complicated fuel supply market. Please do not hesitate to contact me for further information.

Sincerely,

Catherine H. Reheis-Boyd
President and CEO

Sophie Ellinghouse
Vice President, General Counsel & Corporate Secretary

March 11, 2025

California Energy Commission
Docket Unit, MS-4
715 P Street
Sacramento, California 95814

Uploaded to Docket 25-PIIRA-01

RE: WSPA Comments on February 2025 AB X2-1 Pre-Rulemaking Workshop [25-PIIRA-01]

The Western States Petroleum Association (WSPA) appreciates the opportunity to comment on the California Energy Commission's (CEC) February 25, 2025, pre-rulemaking staff workshop regarding a refinery resupply planning framework to implement Assembly Bill (AB) X2-1 (2024) – specifically, towards developing rules regarding necessary refinery maintenance and turnarounds, including the CEC's authority to establish refinery resupply requirements, pursuant to Public Resources Code (PRC) Section 25354.2.

We appreciate the CEC's ongoing engagement with WSPA member companies to better understand California's gasoline market, particularly around planned refinery maintenance activities and recent refinery transitions and closure impacts on the market. We welcome an ongoing dialogue in search of practical solutions to offset lost production due to planned maintenance. We remain concerned, however, that any attempt by the State to micromanage refinery fuel inventories or refinery maintenance will further complicate California's fundamental, systemic problems, which are a result of decades of intentional State policies that actively restrain locally produced fuel supplies while increasing local refining costs. Such issues will likely only worsen California's susceptibility to price volatility – especially when the few remaining California refineries perform necessary maintenance activities required for safe, reliable, and responsible operations.

WSPA is also concerned that any refinery resupply requirement, if not carefully crafted, could conflict with existing statutory mandates for refiners ***not*** to withhold fuel from the market – which would not only adversely impact the California market but would harm Arizona and Nevada consumers if refineries are required to withhold fuel supplies for the benefit of Californians. These types of impacts to states like Arizona and Nevada could ultimately lead to costly and time-consuming litigation for California's interference with interstate commerce. We therefore urge the CEC to further analyze whether refinery resupply requirements are indeed needed – and at what cost. Any requirement that keeps fuel from the market will require the market to increasingly resort to foreign sources, forcing more long-duration marine imports into a market that may not be short and creating unintended and even more expensive consequences for consumers.

Fortunately, AB X2-1 is clear that the CEC "shall not" adopt a regulation "unless it finds that the likely benefits to consumers from avoiding price volatility outweigh the potential costs to consumers." Resupply requirements that prevent the free transaction of fuel on the open market when and where needed to satisfy demand will distort the market, further restrict available supply, and hurt consumers. We urge the CEC to continue working with WSPA and our member companies to reach a mutually beneficial framework that supports supplying fuel to the market and does not compromise refinery safety while seeking to mitigate potential consumer impacts.

ONGOING PROCEDURAL CONCERNS WITH USE OF EMERGENCY RULEMAKINGS

In addition to concerns regarding the delay in posting workshop presentation slides – which limits the time stakeholders have to review, analyze, and opine on them – WSPA reiterates here its ongoing concerns regarding the continued use of, and reliance upon, truncated emergency rulemaking procedures in implementation of AB X2-1. There is no actual "emergency" as defined by California law; the State has faced structural fuel supply issues for decades, and these problems are entrenched and complex. Considering these rules on an emergency basis denies both the public and stakeholders their right to due process and meaningful engagement in an iterative process with staff. The scope and impact of this proposed regulatory framework demands no less than a full and proper assessment by the CEC, the industry, and the public.

WSPA agrees that it is critical to ensure Californians have adequate and affordable supplies of fuel and are protected from price volatility resulting from structural market influences. But effectively addressing these issues will require proper consideration of refinery-specific variables, relevant market data, and of the functioning of the industry as a whole across three states. Given the importance and complexity of the issues involved, the CEC should not short-change a thorough assessment which could result in workable and effective regulations, and Californians deserve adequate time to review and comment on whatever system emerges from that assessment.

In the future, the CEC should provide workshop materials prior to the start of the workshop. This would provide stakeholders that will be directly impacted by proposed policies with sufficient opportunity to assess potential impacts, inform the CEC as to whether the proposals are consistent with existing statutory and operational requirements, and seek clarification from staff regarding any ambiguous policies or regulatory proposals as far in advance as possible.

WSPA RESPONSE TO CEC PRESENTATION ON PROPOSED RESUPPLY FRAMEWORK

We appreciate the CEC staff's ongoing efforts to better understand California's complex transportation fuel system. However, WSPA believes that a "one size fits all" approach to setting reporting thresholds and exemption pathways is unlikely to solve the State's concerns regarding market volatility for consumers. We urge the CEC to meet individually with each refiner, under the confidentiality protections afforded by the Petroleum Industry Information Reporting Act, to fully understand the implications of the proposed resupply framework on each refiner and to ensure that any such framework would not cause more harm than good.

A resupply threshold can present operational challenges if set too high or too low – because this is refinery-dependent. While we appreciate staff's belief that setting a resupply threshold amount too low may not mitigate price volatility, WSPA also believes that setting a resupply threshold amount too high may not mitigate price volatility either, and instead further starve the market of needed fuel supplies. We would further question whether the CEC has the expertise and capacity to intervene in planned refinery maintenance events that would trigger resupply requirements.

We are also concerned about the prospect of any inconsistent application, and therefore enforcement, under any potential exemption pathways. For example, a proposed "trigger level" of merely 450,000 total barrels in an anticipated event is quite low (using ICF's base case of an 8-week outage, that is only approximately 8,000 barrels per day). We would suggest substantially increasing this amount – and reducing the reporting threshold to at least 90 days – to avoid being overly burdensome and potentially intrusive.

Whether the CEC's goal is to drive industry accountability for managing resupply planning or simply to assess how such decisions are made, WSPA questions whether there may be other frameworks to accomplish this. We look forward to working with the CEC to discuss alternative options.

WSPA RESPONSE TO ICF PRESENTATION ON RESUPPLY BENEFIT COST ANALYSIS

WSPA believes that a thoughtful response would involve reviewing how ICF sourced the data that led to the conclusions presented. A review would assist in our evaluation of ICF's underlying cost-benefit analysis assumptions, including assisting WSPA member companies in assessing how ICF's conclusions would impact refinery operators and to validate whether they are consistent with any statutory or operational requirements and constraints.

For example, ICF assumed a conservative scenario whereby refiners would lose money (at a 25% loss) on marine imports brought in. As this is likely the case for marine cargoes, we question what assumptions were made given increasing constraints placed upon marine imports by the California Air Resources Board through the 2020 At-Berth Regulation amendments and other regulations, and for refiners that may have limited access to marine terminals. Furthermore, the assertion that a resupply plan should account for 70-90% of lost production requires further analysis by industry experts to assess feasibility and potential real-world cost impacts, and should be assessed against California market demand rather than refiner production. Specifically, WSPA is concerned about the following analysis assumptions:

1. *Overestimation of Consumer Benefits*: The analysis may overestimate the benefits to consumers by assuming refiners were not already utilizing resupply plans during benchmark events. ICF assumes that an 8-week planned refinery outage event resulted in a total gasoline production loss of 2.5 million barrels. However, the actual impact on prices may be minimal if other factors – such as global oil prices, consumer demand, and market dynamics – continue to play a dominant role.
2. *Underestimation of Compliance Costs*: The analysis might underestimate the costs associated with compliance for refinery operators. Implementing resupply requirements, rather than allowing refineries to implement their own resupply plans – which refiners have been doing for decades, could necessitate uneconomic strategies to secure non-spot market resupplies (e.g., marine imports) and additional capital to guarantee inventories. These costs could be passed on to consumers, potentially leading to higher gasoline prices. This is similar to the concerns we have highlighted around managing mandated inventory levels and how that may reduce the available supply for consumers, thereby increasing costs.
3. *Lack of Flexibility and Potential Conflicts*: The proposed resupply requirements may lack the necessary flexibility to take advantage of unique operational opportunities identified within 60 days prior to planned maintenance or economic supply opportunities identified during the planned maintenance event. This rigidity could result in compliance difficulties and potential conflicts with existing statutory requirements that prohibit refiners from withholding fuel from the market. WSPA has emphasized the need for flexibility in resupply source, quantity, and timing to minimize consumer costs and to avoid unintended consequences.

WSPA intends to provide additional comments to the docket regarding ICF's gasoline forecast model pending a detailed review of their modeling assumptions.

WSPA RESPONSE TO DPMO PRESENTATION ON ECONOMIC CONSIDERATIONS

WSPA reiterates here that a thoughtful response would involve understanding the assumptions used in the Division of Petroleum Market Oversight's (DPMO) cost-benefit analysis. The DPMO's claim that price increases are due to refinery outages has been disputed in the past;

there are numerous underlying reasons for California's rising gasoline prices, including the permanent loss of refinery production, providing boutique fuel blends to an isolated fuel market, minimum wage increases at retail stations, fluctuating crude oil prices on the global market, and the increasing cost of compliance with California-specific regulations (e.g., the Low Carbon Fuel Standard and the Cap-and-Trade Program).

WSPA has repeatedly raised warnings[1] regarding the State's attempt to micromanage California's gasoline inventory supplies and refinery maintenance events. Unfortunately, these warnings appear to have gone unheeded and, since then, another California refinery has opted to close. As part of prior comment letters – including regarding the DPMO's past presentations – we have repeatedly expressed concerns that California's policies present a recipe for increased fuel costs for the consumers of California and potentially reduced fuel supplies to California, as well as Arizona and Nevada.

Yet the DPMO's ongoing attribution of consumer price increases to refinery outages and "profit spikes" for industry continues to fail to appreciate both indirect and direct pricing factors, and also fails to explain why a refiner in a competitive free market would willingly schedule maintenance activities during the busiest demand periods. Basic refinery operations necessitate that tanks will always be partially used to ensure optimal and safe rates for refining operations, as some tank applications can have upstream operational effects, necessitating a reduction in unit rates when the tank levels are too high. In the simplest of terms, if a refiner has two similarly sized tanks, with demand and production balanced, an operator will only have an approximately 50% utilization rate as one tank will be filling at the same rate as the other tank is emptying. As a result, any effort to force the industry to store more product in existing storage vessels would *reduce* refinery production and *increase* supply variability – counter to what the DPMO and CEC are striving to achieve.

CONCLUSION

WSPA appreciates the opportunity to provide these comments on fuel supply issues of critical importance to all California consumers – and consumers of other states dependent on California's refinery production – who rely on affordable and reliable sources of transportation fuel every single day. These comments are based on WSPA's review of the materials and statements at the workshop, and we reserve the right to amend these comments or add to the docket as necessary to reflect additional materials or changes in the CEC's decisions.

Please do not hesitate to contact me with any additional questions.

Sincerely,

S. Ellin

Sophie Ellinghouse
Vice President, General Counsel & Corporate Secretary

[1] Western States Petroleum Association Comments - WSPA Comments on Gasoline Supply Reliability Workshop 9-10-2024 (Docket #23-SB-02); September 10, 2024 at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-SB-02

WSPA
Sophie Ellinghouse
Vice President, General Counsel & Corporate Secretary

March 17, 2025

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Sacramento, California 95814

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RE: WSPA Comments on AB X2-1 Refinery Resupply Planning Pre-Rulemaking Workshop [25-PIIRA-01]

The Western States Petroleum Association (WSPA) appreciates the opportunity to comment on the California Energy Commission's (CEC) March 5, 2025, pre-rulemaking workshop on refinery resupply planning to implement Assembly Bill (AB) X2-1 (2024) and Senate Bill (SB) X1-2 (2023) – specifically, the refinery resupply framework and draft "express terms,"[1] pursuant to Public Resources Code (PRC) Section 25354.2. WSPA acknowledges the CEC's ongoing dialogue with WSPA member companies to better understand planned refinery maintenance activities, and efforts by staff to release the proposed express terms in advance of this workshop. However – given the unusually short comment period, even in an emergency rulemaking proceeding – WSPA recommends that materials be released at least five business days (not calendar days) in advance to afford the public and affected industry stakeholders the opportunity to review, assess impacts, and prepare well-informed comments in time for the workshop.

WSPA reiterates its concerns with any State attempt to micromanage refinery fuel inventories. The CEC has a limited knowledge of complex refinery operations, and its lack of technical expertise leaves open great potential here for unintended consequences that can end up hurting California consumers. If the CEC is going to insist on adopting a refinery resupply policy, any such policy must provide maximum flexibility for refinery operators while minimizing any potential consumer impacts associated with compliance. Indeed, AB X2-1 expressly forbids the CEC from adopting any such regulation "unless it finds that the likely benefits to consumers from avoiding price volatility outweigh the potential costs to consumers." WSPA is concerned that the CEC does not currently have the facts in front of it to legitimately support such a finding with respect to imposing a refinery resupply requirement.

Any refinery resupply requirement, if not carefully crafted, could conflict with existing statutory requirements in SB X1-2 for refiners ***not*** to withhold fuel from the market – such withholding can potentially result in market distortions and undesirable price impacts due to the purposeful and artificial reduction of immediately available supply to the market, and could violate California's Cartwright Act requirements. These potential adverse impacts very likely would extend to Arizona and Nevada as well, and make it harder for those states to secure needed supplies of fuel in the face of regulations expressly favoring Californians' access to fuel. These types of interstate impacts could ultimately lead to costly and time-consuming litigation for California's interference with interstate commerce. In short, the adoption of a "one size fits all" rule for a complex issue such as California refinery fuel inventories has the potential to harm California

[1] CEC "Draft Language Refinery Resupply Plans" California Code of Regulations, Title 20, Chapter 15 Refinery Maintenance Timing, Article 1 Refinery Maintenance Scheduling, Section 3400; dated February 28, 2025.

consumers more than help them. Additionally, it is deeply concerning that the CEC would impose civil penalties upon a refinery operator for either failing to perform resupply under an approved plan, or where the CEC's Executive Director has denied a plan despite the need for planned or unplanned refinery maintenance when legitimate operational, safety, and/or uncontrollable reasons exist.

WSPA continues to believe that the CEC's analysis (as informed by consultants) is likely overestimating the assumed consumer benefits while underestimating compliance costs. It is wrong to assume that refiners are not already utilizing resupply plans during benchmark events, just as it is incorrect to assume that factors such as global crude oil prices and market dynamics may not have dominant roles to play in impacting prices. Further, implementing resupply requirements could necessitate uneconomic strategies to secure non-spot market resupplies and additional capital to guarantee inventories that could potentially lead to higher gasoline prices. Not providing the necessary flexibility to take advantage of unique operational opportunities could result in compliance difficulties and potential conflicts with existing statutory requirements that prohibit refiners from withholding fuel from the market. WSPA previously emphasized the need for flexibility in resupply source, quantity, and timing to minimize consumer costs and avoid unintended consequences.

WSPA RESPONSE TO DRAFT REFINERY RESUPPLY PLANS (EXPRESS TERMS)

WSPA has identified numerous issues and concerns with the CEC's draft refinery resupply plan language ("Proposed Refinery Maintenance Scheduling Rule") and offers the following suggestions where appropriate.

§3400 – Definitions

The following proposed definition requires technical modifications:

- **"Seasonal specification" [§3400(e)].** The CEC's proposed definition is incomplete. Reid Vapor Pressure is only one specification that changes between summertime and wintertime blends. The California Air Resources Board (CARB) also sets a different standard for the T50 distillation specification, and California Business and Professions Code §13440 calls for gasoline to meet ASTM D4814, which has several specifications that differ between seasons.

§3401 – Refinery Maintenance Scheduling

- **Reporting threshold [§3401(b)(2)].** The CEC's reporting threshold to require submittal of a "Refinery Maintenance and Turnaround Supply Plan" in §3401(b)(2) is inappropriate.
    - §3401(b)(2) proposes to set a "trigger level" at "more than 450,000 barrels total" or 20,000 barrels per day for at least 21 days. Understanding that there will likely be operational complexities should the CEC set a threshold that is either too low or too high, as either may not mitigate price volatility, we question the appropriateness of 450,000 total barrels. We look forward to hearing from the CEC and the Division of Petroleum Market Oversight (DPMO) regarding the basis of how a suitable volume threshold for resupply plans was determined. WSPA cautions the CEC that there appears to be no perfect threshold amount that would both protect consumers and not place undue burden on refiners and the CEC.
    - §3401(b) requires refiners to submit their resupply plan "at least **120 days** prior" to a qualifying planned maintenance or turnaround event. WSPA recommends that this be changed to "not prior to **90 days**" given the impracticality of assessing significant global market changes that can happen between 30 to 120 days. An extended time horizon would therefore offer little benefit to the CEC in its attempts to assist refiners in finding affordable consumer resupply inventory. Further, the rule does not address the scenario of a qualifying planned maintenance or turnaround event that occurs inside the 120-day

(or 90-day) window. WSPA recommends these scenarios be expressly eligible for exemption under §3402, particularly if resupply is not feasible.

- **Spot market purchases [§3401(c)].** First, WSPA is perplexed by the CEC's presumption that refiners can predict how resupply sourcing plans would impact the California market. The ability to do so would necessarily require participation in the spot market, which would be precluded in §3401(c)(3). Second, restricting spot market participation in order to resupply California's market is likely demanding the impossible. Refiners cannot demonstrate, or even provide evidence of impacts, prior to participation in the spot market. WSPA strongly recommends that this subsection be modified to allow for spot market participation to help address any perceived resupply problem. Third, WSPA questions the practical constraints associated with removing spot market transactions as a viable resupply option as doing so would force California's refiners to take costly imports with timing risks. Such an approach would likely hurt California consumers, not help them. WSPA strongly suggests that the CEC better understand the potential impacts of dictating spot sales.
- **85% resupply [§3401(c)(1)].** The proposed rule fails to distinguish between resupply of contract volumes versus spot volumes, which is a critical distinction. WSPA believes it is inappropriate to require refiners to resupply spot sale volumes at 85%; spot sale resupply should only be required if market conditions demand it, and even then, the spot sale resupply requirement should be the minimum amount demanded by the market. Otherwise, the rule unnecessarily burdens refiners with the business risk of bringing supplemental spot volumes into a market that does not need additional volume.
- **1.3-barrel multiplier [§3401(c)(1)(i)].** The proposed language counting each barrel of resupply obtained via imports to count as 1.3 barrels requires further clarification.
- **Market availability [§3401(c)(2)].** WSPA presumes that "same rate" means *product* and not *price*; if so, this should be appropriately clarified in the proposed regulatory text. WSPA otherwise questions whether this proposal is authorized under SB X1-2 or AB X2-1, as the meaning is unclear. Any price "cap" must adhere to strict procedural and analysis requirements under both statutes, neither of which are not legally satisfied here.
- **Penalties [§3401(e)].** WSPA has significant concerns with the CEC Executive Director's proposed authority to grant or deny a Refinery Maintenance and Turnaround Supply Plan, in whole or in part, and then assess civil penalties for a denial. The decision-making authority is not associated with any standard; that lack of specificity, especially when associated with a potential civil penalty, raises serious due process concerns.
- **Reporting intervals.** The industry supports transparency but believes additional reporting will be overly burdensome for all involved. We question the CEC's ability to manage the number of planned versus actual resupply reports – particularly given that the proposed language is also void of guidance in how the CEC or industry should manage the process for what is considered substantial updates or changes needed to resupply plans.
- **Planned exports.** Refineries may need to cancel exports of non-CARBOB optimal (higher sulfur, higher benzene) fuel blendstock to meet resupply needs during significant events. Therefore, it is recommended that the proposed language acknowledges this necessity for managing resupply.

§3402 – Request for Exemption

- WSPA strongly recommends that the CEC detail a well-defined and clearly understood exemption pathway process – this would include how it would be administered and governed in the event of any disagreement. The exemption process, as currently drafted, gives the CEC excessive discretion in determining exemption eligibility and provides insufficient certainty for refiners to comply with the rule.
- The CEC's proposal does not provide necessary flexibility for refiners to source the most readily available and affordable resupply options at the start of, or during, a planned event. Because the proposed regulation is seemingly intended to lock resupply plans in, it would

eliminate other opportunistic solutions that would likely benefit California consumers after resupply plans are approved. Eliminating such flexibility is a critical concern for industry as in-State refiners must stay economic. As the primary goal is to economically replenish lost production, the CEC should not be dictating the method by which industry does so; rather, the CEC should be providing an exemption pathway after work has commenced if an extraordinary issue arises.

- The CEC's proposal does not provide any flexibility to address material factors – which are likely to be outside of industry's control – but are reasonably close to meeting planned resupply.
- WSPA questions how the CEC would propose to address any extraordinary market conditions that may occur before a planned maintenance event. This includes any unplanned refinery maintenance activities (including those elsewhere in the California market), any significant and materials impacts affecting consumer demand, any geopolitical changes that impact imports given California's significant and growing susceptibility to the global market, and any delays associated with over-water imports.

WSPA RESPONSE TO DPMO COMMENTS

The DPMO contends that this regulation is justified and necessary to ensure that refiners adopt responsible resupply mechanisms. According to the DPMO, the current market lacks adequate incentives to address supply constraints associated with essential refinery maintenance.

Refiners already implement measures to mitigate the impact of planned outages on gasoline supply. For example, they may increase production prior to an outage, import additional supplies, or utilize inventory reserves to maintain a stable supply during maintenance periods. These proactive steps demonstrate that refiners are motivated to ensure product availability to fulfill their contractual obligations or supply the market during any planned or unplanned events involving competitors' inability to meet California market needs. Introducing further accountability measures may impose unnecessary regulatory burdens and increase costs to consumers without significantly enhancing supply reliability.

The DPMO further asserts that this regulation, as written, provides sufficient flexibility to allow refiners to remain economically viable under California market constraints. However, we remain concerned that the DPMO and CEC should be researching methods of protecting existing market incentives to replenish lost production without prescribing or locking in the specific methods that are in or out of scope for replenishment.

WSPA SUPPLEMENTAL RESPONSE TO ICF RESUPPLY COST-BENEFIT ANALYSIS

WSPA still questions ICF's cost-benefit analysis supporting the proposed regulation. It is critical to have additional transparency and time to conduct an accurate cost-benefit analysis to ensure the CEC has the data necessary, per AB X2-1, to decide whether regulations will impose more harm than good for consumers. It is believed that this analysis lacks critical sensitivities, which may underestimate costs and overestimate benefits for these proposed resupply plans or the potential of regulating inventory. In addition to consumer costs, there are interactions between CARB's policies on marine emissions and regulations aimed at supply reliability that require thorough examination.

WSPA requests detailed information regarding the assumptions in ICF's worst-case resupply costs, including: the percentage of imports or use of other mechanisms assumed to manage resupply; how resupply assumes the use of imported finished fuels versus imported blending components; whether benchmarking scenarios regarding prices accounted for the resupply costs already incorporated and performed in past planned maintenance activities; whether operational slowdowns or other risks due to resupply plans were included; and whether any analysis was conducted on how the resupply plans may conflict with current California environmental policies for stationary and marine mobile sources.

CONCLUSION

WSPA appreciates the opportunity to provide these comments on fuel supply issues of critical importance to all California consumers – and consumers of other states dependent on California's fuel supply chain – who rely on affordable and reliable sources of transportation fuel every single day. These comments are based on WSPA's review of the materials and statements at this and the prior February 25, 2025, workshop, and we reserve the right to amend these comments or add to the docket as necessary to reflect additional materials or changes in the CEC's decisions.

Please do not hesitate to contact me with any additional questions.

Sincerely,

Sophie Ellinghouse,
Vice President, General Counsel & Corporate Secretary

MINIMUM GASOLINE INVENTORY REQUIREMENTS

Prepared for
Western States Petroleum Association

Prepared by
The Brattle Group

Principal Investigator
James Read

August 2024

Assignment

1. My understanding is that the California State Legislature will be considering legislation that would require petroleum refiners to maintain minimum inventories of gasoline. The Western States Petroleum Association (WSPA) has asked me to describe the economics of inventory decisions, to identify possible consequences of imposing minimum gasoline inventory requirements, and to set out the economic analysis that would be needed to assess the costs and potential benefits of such requirements.

The Gasoline Supply Chain

2. It will be helpful to have the gasoline supply chain in mind as we describe the functions and costs of petroleum inventories in the production and consumption of gasoline.

3. The gasoline supply chain starts with the extraction of crude oil from on or off-shore oil fields.[1] Crude oil is processed and refined to produce a slate of petroleum products, one of which is

[1] This description of the supply chain omits the exploration, discovery, and assessment of oil fields that precedes the drilling and completion of oil wells and the extraction of crude oil.

gasoline. Gasoline blendstocks are combined with ethanol at the "rack", where finished gasoline is transferred to distributors for sale to service stations and other retailers. The production of crude oil, the refining of crude oil to produce gasoline and other petroleum products, and the distribution and retailing of gasoline are interconnected by transportation modes that may include marine (tanker or barge) and/or rail as well as pipeline and motor freight (tanker truck). Crude oil and petroleum-product storage facilities and inventories are located at various points along the supply chain.

4. The preceding is a functional description of the supply chain. The commercial organization of these activities includes integrated petroleum companies that perform multiple functions as well as independent firms that perform a single function. Some pipelines operate as common carriers whereas others are operated solely for the benefit of the owner. Similarly, some storage tanks are available for lease by merchant storage companies whereas others are not.

5. California and the other western states of Washington, Oregon, Nevada and Arizona are often described as an "economic island" in the U.S. petroleum markets because they are not connected via pipeline to the U.S. Gulf Coast or other major production centers in the U.S. California is further separated from other U.S. gasoline markets in that the gasoline sold in California must meet unique specifications—more stringent specifications than those required in the other states. At present there are nine refineries within California that produce gasoline blendstocks that meet California gasoline standards (CARBOB).[2] This number has declined by two in the last four years with the conversions of the Marathon Martinez and Phillips 66 Rodeo facilities to production of renewable diesel fuels. The demand for gasoline in California now exceeds the production capacity of refineries located in California.

6. As a consequence of the supply-demand imbalance in California, marginal supplies of California-specification gasoline must be imported from out-of-state refiners or from refiners located overseas—in East Asia, for example. California is not connected via pipeline to out-of-state refiners, so imports must be transported over the water. The increasing reliance on remote refineries to satisfy the demand for California gasoline results in higher gasoline costs and longer delivery lead times due to the additional layer of transportation.[3] It also exposes California gasoline consumers to increased uncertainty about gasoline costs, since marine transportation rates are very volatile and because (in the case of gasoline imported from overseas) of the exposure to foreign exchange and other country risks. Prices in competitive

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2 *Draft Transportation Fuels Assessment*, CEC, May 2024.

3 Marine cargoes from other states are subject to the Jones Act. Cargos from overseas take three to six weeks to arrive in California, according to the *Draft Transportation Fuels Assessment*.

markets are determined by the cost of marginal supplies, so the higher and more volatile costs of imported gasoline imply higher and more volatile prices for California gasoline consumers.

7. An important link in the gasoline supply chain is hidden in the preceding description of the supply chain: California port facilities. Most of the crude oil consumed by California petroleum refiners—approximately 75 percent—is imported from out-of-state suppliers via marine ("over the water") transportation. Furthermore, although California refineries produce most of the gasoline consumed in California—approximately 90 percent—California has been importing increasing amounts of gasoline because of the aforementioned supply-demand imbalance: in-state refiners no longer have sufficient production capacity to satisfy demand. Thus the supply of refinery feedstock (crude oil) and increasingly the supply of gasoline blendstocks rely on California port facilities. As a result, the supply of gasoline that meets California specifications is also subject to physical and regulatory constraints at California ports.

8. At the end of the gasoline supply chain are owners and operators of motor vehicles, used for personal, commercial, industrial or other transportation purposes. Retail gasoline prices reflect the cost of crude oil plus the costs of transportation, storage, refining, and distribution plus several layers of federal, state, and local taxes and other levies. End users, too, hold inventories of gasoline—in motor vehicle fuel tanks.

Inventory Economics

9. *Why firms and households hold inventories*. The economics literature identifies five motives for holding inventories (also referred to as "stocks") of commodities.[4] These motives are the economic functions that inventories can serve. They are, in qualitative terms, the potential benefits of holding inventories.

   a. *To enable efficient order sizes*. Most commodities cannot be shipped and received continuously—they are delivered in discrete quantities. As a result, buyers must have sufficient storage capacity to accept agreed shipment sizes. Once in storage at the receiving end, inventories can be drawn down as needed. Efficient inventory sizes reflect tradeoffs between the purchase price of the commodity, the time and expense of arranging and placing orders, the costs to build and maintain storage facilities, and the carrying costs of commodities in inventory. For example, it is sometimes the case that the unit purchase price of a commodity is lower for a large quantity than it is for a small quantity, providing

[4] Ruth P. Mack, *Information, Expectations, and Inventory Fluctuation* (New York: Columbia University Press, 1967) is a comprehensive study of business inventories.

an incentive to purchase more rather than less in each order. Lower frequency purchases may save money on administrative costs too. But large order quantities require greater storage capacity, higher average inventory levels, and longer holding periods. The efficient inventory size reflects a tradeoff between these costs.

b. *To support time-consuming production processes*. Transforming raw materials into products typically is a time-consuming process. Transporting raw materials and finished or intermediate products is time consuming too. Moving products or raw materials in and out of storage can likewise take substantial time. In-process inventory is therefore an unavoidable aspect of many industrial businesses.

c. *To smooth predictable variations in demand and/or supply*. Many industries are characterized by systematic temporal (for example, seasonal) variations in supply or demand. Agriculture is one example. Most agricultural commodities entail an annual cycle of planting, growth, and harvest, so inventories peak at the end of the harvest and decline until the next harvest begins. Natural gas is another example. The demand for natural gas exhibits two peaks each year, one in the winter and another in the summer, the first due to space heating loads and the second to air conditioning loads. Gasoline is still another example. Gasoline consumption in the U.S. peaks during the summer months.

d. *To serve as a buffer against unexpected changes in supply and/or demand*. Carrying extra inventory over and above the amounts needed to sustain production and consumption under normal conditions can provide insurance for the possibility of supply shortfalls or spikes in demand. This could be an unplanned interruption of manufacturing due to severe weather, as just one example.

e. *To arbitrage intertemporal price spreads*. If the forward market price of a commodity exceeds the spot price by more than enough to cover the physical and financial carrying costs, storage owners can earn an arbitrage profit by simultaneously buying the commodity in the spot market, selling it in the forward market, and holding it in storage until the forward delivery date. In the absence of a forward market for the commodity, storage owners can buy the commodity spot and hold it in storage to act on a view that future spot prices will increase by more than enough to offset the costs of storage.

10. *Inventory holding costs*. It is costly to hold commodities in inventory. Storage costs, which include physical and financial components, can be classified as follows.

a. Working capital: Purchasing and holding commodities in inventory requires and ties up working capital. It therefore entails an opportunity cost of capital for the commodities held in inventory. In most cases the cost of capital, when expressed as a rate of return (usually a percent return per annum), is something in excess of the interest rate because commodity prices are volatile, and thus expose inventory holders to the risk of capital gains and losses.

b. Facility capital costs: Storage facilities can sometimes be leased from a third party, in which case the capital investment required to build or acquire the facilities is observed as a rental rate. In many and perhaps most cases, however, the inventory holder must make a capital investment to build or purchase storage capacity. This capital investment can be expressed as an equivalent rental rate using standard methods of financial analysis.

c. Operating and maintenance costs: Firms incur handling costs when they add or withdraw stock from inventory. Firms also incur costs to maintain storage facilities.

d. Other costs: Holding inventories can entail other costs, such as insurance and, if inventories are held for a long time, deterioration or spoilage of the stored commodity.

11. *What determines the size of inventories?* The costs of holding inventories of commodities oppose the potential benefits of having the commodities in process or on hand. Costs and benefits vary as a function of inventory size. Marginal costs of inventories usually increase with inventory size and marginal benefits of inventory decline with inventory size. Inventory sizes reflect management assessments and tradeoffs of anticipated costs and benefits.

Ambiguity in Inventory Data

12. A single storage facility can hold inventories that serve multiple business purposes. It could, for example, hold stocks intended to smooth seasonal variations in demand as well as stocks intended to serve as a buffer for supply shocks. In other words, more than one motive could be at play for some inventory holders.

13. The economics of storage do not dictate the accounting for petroleum inventories—how petroleum inventories are measured and reported.[5] In some data sources, reported petroleum inventories include quantities that are not available for draw down to supplement current production. The line fill in petroleum product pipelines is a good example. So are quantities

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[5] The term "inventory" is quite general, and many types of inventory are not ordinarily thought of as such. See chapter 15 of Richard B. Chase and Nicholas J. Aquilano, *Production and Operations Management* (Homewood, Illinois: Richard D. Irwin, Inc., 1981) for a discussion of this point. For example, petroleum exploration and production companies hold inventories of crude oil in the ground, but in the vernacular of the petroleum industry those are called "reserves". In-the-ground crude oil inventories are accounted for and reported as reserves, not inventories, under Generally Accepted Accounting Principles.

of petroleum products in storage tank bottoms ("tank heels")—quantities that constitute the minimum volume in storage tanks needed to sustain normal business operation. In short, reported inventories are not broken out according to the business functions they are intended to serve—how much is in process versus how much is held to enable efficient order sizes versus how much to smooth seasonal demand variation, and so on. This—the fraction of reported inventories that is actually available to serve as a buffer for supply disruptions—would be important to understand if aiming to manage private-sector inventories indirectly, via regulation.

<u>Cost-Benefit Analysis</u>

14. The preceding exposition identifies the costs and benefits of inventories in qualitative terms. In considering legislation to establish minimum gasoline-inventory requirements, the California Legislature will presumably choose to follow the instructions it gave to the California Energy Commission in SB X1-2 with regard to implementation of a maximum gross gasoline refining margin ("MGGRM"). That is, that California will not enact minimum-inventory requirements unless it finds that the benefits of the requirements outweigh the costs. What follows is a sketch of the analysis that would be needed to assess the costs and benefits in quantitative terms.

15. To start, the terms of the minimum gasoline-inventory requirements would need to be specified in enough detail that it is possible for a team of experts in economics, operations research, and the petroleum industry to assess the costs and potential benefits:

    a. What business entities would be subject to minimum gasoline inventory requirements? Refiners only? What about other companies in the California gasoline supply chain?

    b. How would the minimum gasoline inventory levels be determined for the target companies and what measure of inventories would be used?

    c. Would penalties be imposed for failure to satisfy minimum inventory requirements? If so, how would the penalties be structured?

    d. How much lead time would target companies have to build up inventories to satisfy the minimum inventory requirements—to acquire the storage capacity and purchase the incremental gasoline?

    e. Under what conditions would target companies be allowed to draw down inventories below the minimum levels without incurring penalties? Would drawdown conditions be specified in terms of independently observable variables like market prices or instead determined by decree? Would the size of drawdowns be regulated too? What would be the industry's obligation to rebuild inventories following a drawdown event?

16. My understanding is that the goal of the inventory policy under consideration by the Legislature is to increase the size of California gasoline inventories. It would seek to do this not by creating a State-owned and managed petroleum reserve, but by imposing minimum gasoline-inventory requirements on California petroleum refiners. So far as I know, the terms of the minimum-inventory requirements have not yet been specified.

17. Petroleum market participants—refiners, distributors, storage companies, energy traders, and others—evidently do not expect that investments in larger gasoline inventories would be profitable. That is, they do not expect that the marginal benefits would exceed the marginal costs. If they thought investments in additional inventories would be profitable, they would expand inventories on their own initiative. Their decisions not to do so imply that requiring refiners to hold additional gasoline inventories would impose on them *net costs*. On the other hand, the fact that the California Legislature is contemplating a minimum gasoline-inventory requirement suggests that some legislators think additional gasoline inventories would create positive externalities—that is, *net external benefits*—that would offset the net private costs. Identifying the source of these external benefits would be critical in a cost-benefit analysis of minimum-inventory requirements.

18. A comprehensive cost-benefit analysis would be a major undertaking; it would require a lot of information and entail a lot of analysis. This includes projections of the size of the incremental inventories induced by the minimum gasoline-inventory requirement, assessment of the availability and cost of storage sufficient to accommodate incremental inventories, estimation of the likelihood, magnitude, and duration of possible future supply events (refinery outages, for example), development of a gasoline supply schedule that includes gasoline imported from out-of-state and overseas producers, development of a demand schedule for gasoline, and projections of incremental-inventory drawdowns. It would also require a model of the relationship between gasoline inventories and prices.

19. A minimum gasoline inventory requirement, if set higher than the minimum inventories that the target companies would maintain in the ordinary course of business, would be binding in at least some future "states of the world". In other words, there will be at least some scenarios in which firms subject to minimum-inventory requirements will decide to hold larger gasoline inventories than they would absent those requirements. The likelihood of such scenarios would depend in part on the minimum inventory levels and other terms (e.g., penalties for non-compliance) of the minimum-inventory regulations.

20. Projecting the *incremental inventories* induced by minimum gasoline inventory requirements would be one task in a cost-benefit analysis. Incremental inventories are the *additional*

quantities of gasoline that target companies would decide to hold—quantities in excess of levels they would otherwise hold—to comply with the minimum-inventory regulations or to reduce the likelihood of non-compliance to a level acceptable to company managers, given the attendant penalties. It is the size of these incremental inventories that will determine the additional working capital needed to fund larger gasoline inventories and the additional storage capacity that the industry would need to acquire to hold larger gasoline inventories.

21. The purchases of gasoline (or reductions in gasoline sales) needed to build inventories in response to minimum-inventory requirements would tend to increase market prices and reduce gasoline consumption. Inventory build would presumably be gradual, if permitted by the terms of the minimum-inventory regulations, in order to minimize market impact. Nevertheless the market impact would affect all gasoline purchases, not just purchases made to build up inventories; current gasoline consumers would pay elevated prices too. The losses in consumer surplus associated with the incremental inventory buildup should be part of a cost-benefit analysis of minimum-inventory requirements.

22. Presumably the anticipated benefits to a minimum-inventory requirement are based on the assumption that the petroleum industry would have larger gasoline inventories on hand to draw down in the event gasoline becomes more scarce than expected, and that in at least some such events the industry would draw down some of the incremental inventories, thereby supplementing supply and mitigating the price increase that would otherwise have ensued. The external benefit of the minimum-inventory regulations in such events could be expressed as a gain in consumer surplus due to the *incremental drawdown*—the *additional* drawdown attributable to the availability of the incremental inventories—and the associated market impact. The gain in consumer surplus would depend on the market price of gasoline and how much gasoline was sold *with* the minimum-inventory requirements in place versus what the market price of gasoline would have been and how much gasoline would have been sold *absent* those requirements. Contingent prices and quantities would depend on the inventory level and the size of the incremental draw down, and on the gasoline supply and demand schedules. Like the loss in consumer surplus due to the buildup of incremental inventories, the potential gain in consumer surplus due to potential drawdowns would be part of a cost-benefit analysis of minimum-inventory requirements.

23. Note that after a scarcity event resolved, target companies would again need to make additional purchases of gasoline to restore inventories to planning levels. Purchases of gasoline to restore inventories, like purchases during the inventory buildup, would tend to increase market prices and reduce gasoline consumption. The associated losses in consumer surplus should likewise be included in a cost-benefit analysis of minimum-inventory requirements.

24. A cost-benefit analysis would need to consider the possibility that minimum-inventory regulations would not work as intended. Two issues come to mind. First is the potential for

crowding out, that is, the possibility that incremental inventories held by target companies would be partly offset by reductions in inventories held by market participants who are not subject to the inventory regulations, say at the distribution, retail, or end-user stages. Second, target firms might not draw down incremental inventories when gasoline is scarce, or they might draw down substantially less than anticipated by policy makers, perhaps because they want to avoid a non-compliance penalty or because of uncertainty about the duration or magnitude of supply shortfalls. Thus, in addition to projecting the size of incremental inventories held by target companies, the cost-benefit analysis needs to anticipate how the target companies will utilize the incremental inventories. The analysis also needs to anticipate how market participants other than the target companies will respond to the incremental inventories.

25. The cost of incremental storage capacity in both the short and longer terms would be a key issue. In principle, the options for acquiring additional storage include (a) leasing storage from a merchant storage company or other third party, (b) chartering an oil tanker ("floating inventory"), and (c) building new storage facilities. If incremental inventories are small, recent lease rates may provide an adequate indication of the associated storage costs. As to floating storage, tanker freight rates are extremely volatile, so current spot rates are probably not a reliable guide for purposes of this analysis. Forward rates would be a better guide but still subject to a high degree of uncertainty. New storage facilities would take substantial time to plan, permit, and build, so would become available only after a long lead time. The costs to build new storage capacity would provide a basis for estimating long-term storage costs but not short or intermediate-term storage costs.

<u>Potential Unintended Consequences</u>

26. Petroleum market participants evidently do not see net benefits to holding additional inventories, otherwise they would do so on their own initiative. Therefore, even without knowing the terms of minimum gasoline-inventory requirements and conducting a cost-benefit analysis, we can identify some potential adverse consequences. Specifically, if minimum-inventory regulations actually do stimulate an increase in gasoline inventories held by target companies—then average inventories will increase, which implies that average inventory carrying costs and the cost of producing gasoline will increase.

27. Possible consequences of the increase in costs associated with meeting a minimum-inventory requirement include:

    a. *Shift in petroleum product mix*. Since minimum inventory requirements would apply only to sales of gasoline produced to meet California gasoline specifications, they will create an incentive for California refiners to reduce production of CARBOB and increase production of gasolines and other petroleum products that are not subject to minimum inventory requirements.

b. *Decline in California refining capacity*. The increase in production costs—if not offset by shifts in the petroleum product mix—implies a reduction in refinery profitability. This means that incentives to maintain and refurbish refineries and ancillary equipment will be diminished to some degree. It suggests the possibility of an acceleration of retirements and conversions to alternative uses (for example, renewable fuels production), which would result in a decline in the in-state refining capacity capable of producing CARBOB.

c. *Diminished reliability of supply*. The increase in production costs due to minimum inventory requirements also implies a possible reduction in incentives to maintain capacity, with diminished reliability of these resources—a higher frequency of unplanned outages, for example—a possibility.

28. Forecasts of product switching, the timing of refinery retirements, conversions to produce low-carbon fuels, or other refinery redeployments would be difficult for outsiders; they would require access to business-confidential information for the incumbent refineries, including the amount and timing of capital expenditures required to maintain and refurbish facilities, the options and costs to revise the mix of petroleum products, and the options and costs for redeployment. Nevertheless, the possibilities of these outcomes ought to be considered in a cost-benefit analysis.

<u>Summary</u>

29. It is unclear at this point how or whether a minimum gasoline-inventory requirement would induce larger gasoline inventories. If we assume for sake of argument that it would, it is clear that inventory carrying costs and thus petroleum refining costs would increase, but it is not at all clear how or whether an increase in inventories would generate external benefits to offset the net costs to the refining industry. We don't know how the target companies would utilize the assumed additional inventories, nor do we know how other market participants would respond to additional inventories. Perhaps most important, the source of external benefits, which would be the basis for a minimum gasoline-inventory requirement, has not been identified.

30. It is possible that a minimum gasoline inventory requirement would induce the California petroleum industry to hold larger gasoline inventories and that the incremental inventories would yield benefits to California consumers. Much analysis would be needed reach that conclusion with confidence, however. In the meantime, it is clear that the private returns to investments in additional gasoline inventories do not justify the costs, as revealed by the fact that market participants are not undertaking those inventory investments on their own

initiative. The costs and potential benefits of additional gasoline inventories need to be thought through and evaluated carefully before reaching the conclusion that the benefits of a minimum gasoline-inventory requirement would outweigh the costs.

Title 13 and Title 17, California Code of Regulations
California Air Resources Board

5-Day Public Notice and Comment Period

Emergency Amendment and Adoption of Vehicle Emissions Regulations

The California Air Resources Board (CARB or Board) proposes to adopt emergency vehicle emissions regulations (the "Emergency Vehicle Emissions Regulation") that will amend California Code of Regulations, titles 13 and 17, and adopt new sections into California Code of Regulations, titles 13 and 17. The amendments would confirm that, until a court resolves the uncertainty created by the federal government's actions, certain antecedent regulations (displaced by Advanced Clean Cars II and Omnibus) remain operative (as previously adopted) with the caveat that CARB may enforce Advanced Clean Cars II and Omnibus, to the extent permitted by law, in the event a court of law holds invalid the resolution purporting to disapprove those waivers. The Emergency Vehicle Emissions Regulations will become effective upon filing with the Office of Administrative Law.

Written Comment Period and Submittal of Comments

Government Code section 11346.1(a)(2) requires that at least five working days prior to submission of the proposed emergency rulemaking to the Office of Administrative Law (OAL), CARB provides a notice of the proposed emergency rulemaking to every person who has filed a request for notice of regulatory action. After submission of the proposed emergency rulemaking to OAL, interested parties will be provided five calendar days to submit comments on the proposed emergency regulations, as set forth in Government Code section 11349.6.

CARB intends to submit the Emergency Vehicle Emissions Regulation to OAL on September 22, 2025. The submitted action will appear on the list of "Emergency Regulations Under Review" on OAL's website at:
https://oal.ca.gov/emergency_regulations/Emergency_Regulations_Under_Review/.

Comments must be submitted in writing directly to OAL:

Postal mail: OAL Reference Attorney
300 Capitol Mall, Suite 1250
Sacramento, California 95814
Fax Number: (916) 323-6826

Electronic submittal: *staff@oal.ca.gov*

CARB requests that comments submitted via email include a carbon copy ("cc") to *cotb@arb.ca.gov*. Additionally, CARB requests but does not require that interested parties submit written comments reference the title of the proposal in their comments to facilitate review.

Please note that under the California Public Records Act (Government Code section 7920.000 et seq.), your written and oral comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request.

Finding of Emergency

On January 6, 2025, U.S. EPA published its notices of decision granting California's requests for Clean Air Act preemption waivers, authorizing the enforcement of the LEV IV regulations (as part of the Advanced Clean Cars II regulation) and the Omnibus regulation.[1] On June 12, 2025, President Trump signed congressional resolutions that purported to disapprove these and one other waiver not at issue here.[2] California and a coalition of states promptly filed suit to challenge these resolutions targeting three waiver actions granted to California.[3] That case remains pending.

The congressional resolutions have introduced an unprecedented degree of uncertainty into the California market for new motor vehicles. Specifically, the resolutions purported to invalidate preemption waivers authorizing enforcement of more recently adopted (and more stringent) vehicle emission standards, which themselves had displaced earlier-adopted regulations (applicable to all future model years), for which preemption had also been waived. That has left questions about which regulations apply.

Most recently, in an exhibit to a court filing on September 4, 2025, vehicle manufacturers argued that CARB's earlier-adopted vehicle certification requirements—for which CARB has received separate waivers not affected by the congressional resolutions and not at issue in the litigation described above—are invalid because those requirements became "defunct" when the more recent, more stringent standards displaced them.[4] Thus, according to the vehicle manufacturer challengers, "amending state law" would be required to revive the earlier-adopted standards even if the displacing standards are ultimately found to be unenforceable on account of Congress's actions. CARB disagrees.

Nevertheless, in the event the vehicle manufacturer's claim were to be deemed correct—that CARB must affirmatively revive its earlier-adopted emissions requirements before it can resume enforcement of them—then CARB must take immediate action to maintain a stable vehicle market in the state and prevent the sale of vehicles into the state that would not be certified to *either* set of standards—*neither* the more recent ones that are subject to the recent congressional action *nor* the earlier-adopted ones that are undisputedly authorized by a federal waiver. Otherwise, in light of these unprecedented circumstances, there may remain questions—for the first time since CARB's program began decades ago—as to whether *any* California standard is in effect. There is therefore an emergency need to clarify the law to confirm that, at a minimum, CARB's earlier-adopted standards, which have extant federal

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[1] 90 Fed. Reg. 642 (Jan. 6, 2025), 90 Fed. Reg. 643 (Jan. 6, 2025).

[2] H.J. Res. 88 (119th Congress), H.J. Res. 89 (199th Congress).

[3] *State of California, et al., v. United States of America, et al.,* (ND Cal., case no. 3:25-cv-04966).

[4] Pl. Mot. For Leave to File Reply in Support of Mot. For Admin. Relief to Expedite, *Daimler Truck North Am. LLC v. CARB*, Case No. 2:25-cv-02255-DC (Sep. 4, 2025), at Exh. 1, page 2 n.3.

preemption waivers not subject to the recent congressional resolutions, are operative. This emergency regulation thus responds to an unprecedented and unanticipated set of circumstances: the suggestion by a regulated party that, for the first time in half a century, CARB has *no* operative emissions standards to which it can certify new motor vehicles to be sold in the State.

Every day that passes without clarity in this matter risks the health of millions of Californians, CARB's ability to enforce its long-standing vehicle emissions certification program (including its ability to ensure vehicles meet emission requirements as sold into California and over their full useful lives), and the stability of the California vehicle market. There are currently over 27 million light-, medium-, and heavy-duty vehicles that operate on California roads, traveling an estimated 305 billion miles annually. Each day, these vehicles emit 290 tons of nitrogen oxides (NOx) and over 200 tons of reactive organic gases (this includes evaporative emissions, if just exhaust emissions the number is 83 tons/day)—both of which are smog precursors—and 11.9 tons of particulate matter smaller than 2.5 microns (Fine PM or PM2.5).

To clarify and ensure that new vehicles and engines can continue to be sold in California, despite the ongoing uncertainty created by the federal government's actions, CARB has taken several steps, including its proposal here to adopt the Emergency Vehicle Emissions Regulations. The amendments proposed here would confirm that, until a court resolves the uncertainty created by the federal government's actions, then at a minimum certain earlier-adopted regulations (displaced by Advanced Clean Cars II and Omnibus) remain operative (as previously adopted) with the caveat that CARB may enforce Advanced Clean Cars II and Omnibus, to the extent permitted by law, in the event a court of law holds invalid the resolutions purporting to disapprove the waivers for those more recent regulations.

Authority and Reference

This emergency regulation is proposed under the authority granted in California Health and Safety Code, sections 38501, 38505, 38510, 38560, 39002, 39003, 39010, 39500, 39600, 39601, 39602.5, 39614, 39658, 39667, 40000, 43000.5, 43013, 43016, 43018, 43100, 43101, 43102, 43104, 43105, 43105.5, 43106, 43154, 43200, 43200.1, 43204, 43205, 43205.5, 43210, 43211, 43212, 43214, 43600 and 43806, and Vehicle Code sections 27156 and 28114. This action is proposed to implement, interpret, and make specific sections 38501, 38505, 38510, 38560, 38562, 38580, 39002, 39003, 39010, 39500, 39600, 39601, 39602.5, 39614, 39658, 39667, 40000, 43000, 43000.5, 43013, 43016, 43018, 43018.5, 43100, 43101, 43102, 43104, 43105, 43105.5, 43106, 43107, 43154, 43200, 43200.1, 43204, 43205, 43205.5, 43211, 43212, 43214, 43600 and 43806 of the California Health and Safety Code; and California Vehicle Code section 28114.

Informative Digest of Proposed Action and Policy Statement Overview (Gov. Code, § 11346.5, subd. (a)(3))

Sections Affected:

Proposed amendments to California Code of Regulations, title 13, sections: 1900, 1956.8, 1961.2, 1961.3, 1962.2, 1962.3, 1965, 1968.2, 1968.5, 1969, 1971.1, 1971.5, 1976, 1978, 2035, 2036, 2037, 2038, 2040, 2111, 2112, 2113, 2114, 2115, 2116, 2117, 2118, 2119, 2121, 2123, 2125, 2126, 2127, 2128, 2129, 2130, 2131, 2133, 2137, 2139, 2139.5, 2140, 2141, 2142, 2143, 2144, 2145, 2146, 2147, 2148, 2149, 2166, 2166.1, 2167, 2168, 2169, 2169.1, 2169.2, 2169.3, 2169.4, 2169.5, 2169.6, 2169.7, 2169.8, 2170, 2317, 2423, 2485, and 2903.

Proposed adoption of new sections 1900.0.1, 1956.8.1, 1961.2.1, 1961.3.1, 1962.2.1, 1962.3.1, 1965.0.1, 1968.2.1, 1968.5.1, 1969.0.1, 1971.1.1, 1971.5.1, 1976.0.1, 1978.0.1, 2035.0.1, 2036.0.1, 2037.0.1, 2038.0.1, 2040.0.1, 2111.0.1, 2112.0.1, 2113.0.1, 2114.0.1, 2115.0.1, 2116.0.1, 2117.0.1, 2118.0.1, 2119.0.1, 2121.0.1, 2123.0.1, 2125.0.1, 2126.0.1, 2127.0.1, 2128.0.1, 2129.0.1, 2130.0.1, 2131.0.1, 2133.0.1, 2137.0.1, 2139.0.1, 2140.0.1, 2141.0.1, 2142.0.1, 2143.0.1, 2144.0.1, 2145.0.1, 2146.0.1, 2147.0.1, 2148.0.1, 2149.0.1, 2317.0.1, 2423.0.1, 2485.0.1, 2903.0.1 in title 13 of the California Code of Regulations.

Proposed amendments to California Code of Regulations, title 17, sections 95300, 95301, 95302, 95303, 95304, 95305, 95306, 95307, 95308, 95309, 95310, 95311, 95312, 95660, 95661, 95662, 95663, and 95664.

Proposed adoption of new sections 95300.0.1, 95301.0.1, 95302.0.1, 95303.0.1, 95304.0.1, 95305.0.1, 95306.0.1, 95307.0.1, 95308.0.1, 95309.0.1, 95310.0.1, 95311.0.1, 95312.0.1, 95660.0.1, 95661.0.1, 95662.0.1, 95663.0.1, and 95664.0.1.

Documents Incorporated by Reference (Cal. Code Regs., tit. 1, § 20, subd. (c)(3)):

See APPENDIX A: Documents Incorporated by Reference.

Background and Effect of the Proposed Emergency Regulatory Action

Existing Advanced Clean Cars and Medium- and Heavy-Duty Vehicle and Engine Regulatory Requirements

Passenger cars and light trucks are a significant source of NOx, other smog-forming emissions and PM2.5 in California, with over 26 million such vehicles on the road, which are estimated to travel over 285 billion miles in 2025. Heavy-duty vehicles add approximately 1 million additional vehicles and an additional 15+ billion miles.

California's Low Emission Vehicle III (LEV III) regulations, adopted on January 26, 2012, and subsequently updated, tightened light-duty and chassis-certified medium-duty vehicle criteria pollutant standards for 2015 through 2025 and subsequent model years.[5] The U.S. EPA granted California's request for a Clean Air Act preemption waiver, authorizing enforcement of these regulations, in 2013.[6] As part of the Advanced Clean Cars II (ACC II) regulations adopted on June 9, 2022, more stringent criteria-emission standards known as Low Emission

[5] The LEV III regulations were subsequently amended in 2012 (Register 2012, No. 32 and Register 2013, No. 1), 2015 (Register 2015, No. 41) and 2018 (Register 2018, No. 50).

[6] 78 Fed. Reg. 2,113 (Jan. 9, 2013)Other parts of this waiver—covering other standards than those at issue here—were purportedly withdrawn in 2019 but reinstated in 2022.; 87 Fed. Reg. 14,332 (Mar. 14, 2022) [restoring waiver].

Vehicle IV (LEV IV) established new requirements for 2026 and subsequent model years, thereby displacing the LEV III criteria pollutant regulation beginning with the 2026 model year.

California first regulated heavy-duty vehicle exhaust emissions in 1969. In 2005 and 2010, U.S. EPA granted waivers for California's medium- and heavy-duty engine and vehicle regulations for diesel and Otto-cycle engine standards.[7] In 2017, the U.S. EPA granted California a waiver of federal preemption for several sets of amendments to CARB's emission standards for medium- and heavy-duty vehicles adopted in 2011, 2008, 2007, and 2006.[8] In 2016, the U.S. EPA granted California's requests for waivers for its on-board diagnostic (OBD) systems for light-, medium-, and heavy-duty vehicles adopted in 2013 (the OBD II and HD OBD regulations).[9] California's Omnibus regulations, adopted in 2020 and amended in 2023, tightened CARB's criteria pollutant standards for medium- and heavy-duty vehicles.[10] Omnibus and Advanced Clean Cars encompass OBD requirements. In 2016, U.S. EPA also granted California a waiver for its Phase 1 Greenhouse Gas emission standards adopted in 2013.[11]

On January 6, 2025, U.S. EPA published its notices of decision granting California's requests for Clean Air Act preemption waivers, authorizing the enforcement of the LEV IV regulations and amendments to OBD requirements (as part of the ACC II regulation) and the Omnibus regulation (including its amendments to OBD requirements).[12] On June 12, 2025, President Trump signed congressional resolutions that purported to disapprove these and one other waiver not at issue here.[13] California and a coalition of states promptly filed suit to challenge these resolutions targeting three waiver actions granted to California.[14] That case remains pending.

The congressional resolutions have introduced an unprecedented degree of uncertainty into the California market for new motor vehicles. Specifically, the resolutions purported to invalidate preemption waivers authorizing enforcement of recently adopted, more stringent vehicle emission standards that had displaced earlier standards that themselves were applicable to all future model years and for which preemption has been waived. That has left questions for at least some regulated parties about which regulations apply, as evinced in the court filing by a manufacturer described above. To clarify and ensure that new vehicles and engines can continue to be sold in California, despite the ongoing uncertainty created by the federal government's actions, CARB has taken several steps, including this proposed adoption of the Emergency Vehicle Emissions Regulations.

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[7] 70 Fed. Reg. 50,322 (Aug. 26, 2005); 75 Fed. Reg. 70,238 (Nov. 17, 2010).

[8] 82 Fed. Reg. 4,867 (Jan. 17, 2017).

[9] 81 Fed. Reg. 78,143 (Nov. 7, 2016), 81 Fed. Reg. 78,149 (Nov. 7, 2016).

[10] *See* Register 2020, No. 4 (26-Z), and Register 2024, No. 22 (31-Z).

[11] The Proposed Greenhouse Gas (GHG) Regulations For Medium- And Heavy-Duty Engines And Vehicles, Optional Reduced Emission Standards For Heavy-Duty Engines, And Amendments To The Tractor-Trailer GHG Regulation, Diesel-Fueled Commercial Motor Vehicle Idling Rule, And The Heavy-Duty Hybrid-Electric Vehicles Certification Procedures, adopted 2014, Register 2014, No. 49; 81 Fed. Reg. 52,680 (June 9, 2016).

[12] 90 Fed. Reg. 642 (Jan. 6, 2025), 90 Fed. Reg. 643 (Jan. 6, 2025).

[13] H.J. Res. 88 (119th Congress), H.J. Res. 89 (199th Congress).

[14] *State of California, et al., v. United States of America, et al.,* (ND Cal., case no. 3:25-cv-04966).

Summary of the Proposed Regulatory Actions

CARB is proposing its Emergency Vehicle Emissions Regulations to clarify that protective emission standards for vehicles and engines remain operative, while ensuring manufacturers can sell vehicles and engines into California despite the emergency the federal government has created through unconstitutional congressional resolutions targeting certain preemption waivers.

To ensure that new motor vehicles can continue to be sold in California, despite the ongoing uncertainty introduced by the federal government into the State's longstanding regulatory program, CARB staff is proposing to amend its regulations to clarify that the criteria pollution provisions of the LEV III regulation (adopted as part of ACC I) and associated on-board diagnostic requirements remain operative, with the caveat that CARB may enforce the more recently adopted LEV IV requirements (adopted as part of ACC II) to the extent permitted by law, in the event a court of law holds invalid the resolution purporting to disapprove that waiver.

CARB staff is similarly proposing to amend its medium- and heavy-duty regulations to clarify that the provisions antecedent to Omnibus[15] remain operative, with the caveat that CARB may enforce the Omnibus regulation, to the extent permitted by law, in the event a court of law holds invalid the resolution purporting to disapprove that waiver.

CARB continues to accept and process certification applications for the LEV IV and Omnibus emission standards. Hence, both sets of standards will be present in the California Code of Regulations during this period of unprecedented uncertainty. Regulated parties may choose to follow either the LEV IV or Omnibus standards or the antecedent LEV III and pre-Omnibus provisions. Regulated parties, however, assume the risk if they choose to certify only to the antecedent provisions, and the congressional resolutions disapproving the waivers of federal preemption under the Clean Air Act are declared invalid.

CARB may also consider other changes to the sections affected, as listed on page 3 of this notice, or other sections within the scope of this notice, during this rulemaking process.

Objectives and Benefits of the Proposed Regulatory Action:

The goal of the Emergency Vehicle Emissions Regulations is to clarify and ensure that new motor vehicles can be sold in California despite the unprecedented uncertainty introduced by the federal government into CARB's longstanding regulatory program. These amendments will ensure that new vehicles and engines sold in California will, at a minimum, meet the emission standards and requirements for which U.S. EPA has granted a waiver that was not targeted by the congressional resolutions.

Environmental and Health Benefits

CARB's Emergency Vehicle Emissions Regulations will provide clarity and ensure that, at a minimum, the pollutant emission standards for new passenger cars, light trucks, and chassis-certified medium-duty vehicles up to 14,000 pounds, which had become status quo starting with the 2017 model year, remain operative. The Regulations will also clarify that the standards

[15] These regulations encompass provisions for OBD systems for light-, medium-, and heavy-duty engines and vehicles, greenhouse gas emissions from medium- and heavy-duty vehicles, and related requirements in the sections of titles 13 and 17 listed as encompassed in this proposal.

antecedent to the Omnibus regulations also remain operative. CARB has enforced LEV III and pre-Omnibus standards, or stricter standards, since those standards went into effect, and thus the proposed regulatory action has no adverse environmental or health impact.

Economic Impacts

CARB does not anticipate any cost or economic impacts from its Emergency Vehicle Emissions Regulations because the compliance pathways available to manufacturers have already been understood for years; and manufacturers have either already achieved or planned to achieve one or more of the compliance pathways.

Comparable Federal Regulations:

Both California and U.S. EPA have authorities to set emissions standards for new motor vehicles and for new motor vehicle engines. U.S. EPA's authority is contained in Section 202(a)(1) of the Clean Air Act.[16]

The California Legislature has placed the responsibility of controlling vehicular air pollution on CARB, and has designated CARB as the state agency that is "charged with coordinating efforts to attain and maintain ambient air quality standards, to conduct research into the causes of and solution to air pollution, and to systematically attack the serious problems caused by motor vehicles, which is the major source of air pollution in many areas of the State."[17] CARB is authorized to adopt standards, rules and regulations needed to properly execute the powers and duties granted to and imposed on CARB by law.[18] Health and Safety Code sections 43013 and 43018 broadly authorize and require CARB to achieve the maximum feasible and cost-effective emission reductions from motor vehicles, including the adoption and implementation of vehicle emission standards and in-use performance standards[19] and by improving emission system durability and performance,[20] resulting in an expeditious reduction of NOx emissions from diesel vehicles, "which significantly contribute to air pollution problems."[21]

CARB is further authorized to adopt and implement emission standards for new motor vehicles and new motor vehicle engines that are necessary and technologically feasible.[22] CARB also has the authority to adopt test procedures and any other procedures necessary to determine whether vehicles and engines are in compliance with the emission standards established under Part 5 of the Health and Safety Code.[23] Finally, CARB has the authority to not certify a new motor vehicle or motor vehicle engine unless the vehicle or engine meets the emission standards adopted by CARB pursuant to Part 5 of the HSC under test procedures adopted pursuant to section 43104[24]

[16] 42 U.S.C. § 7521.
[17] Cal. Health & Saf. Code, §§ 39002, 39003.
[18] Cal. Health & Saf. Code, §§ 39600 and 39601.
[19] Cal. Health & Saf. Code, §43013(a).
[20] Cal. Health & Saf. Code, § 43018(c)(2)
[21] Cal. Health & Saf. Code, § 43013(h).
[22] Cal. Health & Saf. Code, §43101.
[23] Cal. Health & Saf. Code, § 43104.
[24] Cal. Health & Saf. Code, § 43102.

On January 24, 2023, U.S. EPA adopted the EPA-NOx rule which established criteria pollutant emissions standards and test procedures for 2027 and subsequent MY HDEs that are comparable in stringency to the 2027 MY HD Omnibus requirements.

For 2026 model year, U.S. EPA's Tier 3 criteria pollutant standards are similar to the LEV III requirements for non-methane organic gas (NMOG) plus NOx, but not as stringent for particulate matter. On March 20, 2024, U.S. EPA adopted their Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles Rule, that sets new Tier 4 standards to further reduce harmful air pollutant emissions from light-duty and medium-duty vehicles starting with model year 2027. Portions of this rule are identical to elements of the LEV IV requirements for those model years but are more stringent once they are fully phased in by the 2033 model year than the LEV III requirements would be.

On August 1, 2025, U.S. EPA published a notice of reconsideration and proposed repeal of its greenhouse has emission standards for light-, medium-, and heavy-duty vehicles.[25]

An Evaluation of Inconsistency or Incompatibility with Existing State Regulations (Gov. Code, § 11346.5, subd. (a)(3)(D)):

During the process of developing the proposed regulatory action, CARB conducted a search of similar regulations on this topic and concluded these regulations are neither inconsistent nor incompatible with existing state regulations.

Other Statutory Requirements (Gov. Code, § 11346.5 subd. (a)(4))

The Emergency Vehicle Regulations proposal would clarify that certain antecedent regulations remain operative. When these regulations were adopted, any other matters prescribed by statute applicable to CARB or these specific regulations or class or regulations were identified. These antecedent regulations were identified in OAL File Numbers:

- Z-00-1010-10 [Consider Requiring Certain California Light-and Medium-Duty Vehicles to be Subject to Federal Tier 2 Exhaust Standards, and Adopting Additional Exhaust Emission Standards for Heavy-Duty Gasoline Vehicles and Engines],
- Z-01-0828-14 [Amendments Adopting More Stringent Emission Standards for 2007 and Subsequent Model Year New Heavy-Duty Diesel Engines],
- Z-02-0917-02 [Consider the Incorporation of Federal Exhaust Emission Standards for 2008 and Later Model-Year Heavy-Duty Gasoline Engines and the Adoption of Minor Amendments to the Low-Emission Vehicle Regulations],
- Z-2011-1129-12 [Amendments To The California Greenhouse Gas And Criteria Pollutant Exhaust And Evaporative Emission Standards And Test Procedures And To The On-Board Diagnostic System Requirements For Passenger Cars, Light-Duty Trucks, And Medium-Duty Vehicles, And To The Evaporative Emission Requirements For Heavy-Duty Vehicles],
- Z-2012-0626-07 [Proposed Revisions to On-Board Diagnostic System Requirements for Heavy-Engines, Passenger Cars, Light-Duty Trucks, Medium-Duty Vehicles and Engines],

[25] 90 Fed. Reg. 36,288, Aug. 1, 2025.

- Z-2012-0831-01 [Proposed Amendments To The New Passenger Motor Vehicle Greenhouse Gas Emission Standards For Model Years 2017-2025 To Permit Compliance Based On Federal Greenhouse Gas Emissions Standards And Additional Minor Revisions To The LEV III And ZEV Regulations],
- Z-2013-1015-07 [Proposed Greenhouse Gas (GHG) Regulations For Medium- And Heavy-Duty Engines And Vehicles, Optional Reduced Emission Standards For Heavy-Duty Engines, And Amendments To The Tractor-Trailer GHG Regulation, Diesel-Fueled Commercial Motor Vehicle Idling Rule, And The Heavy-Duty Hybrid-Electric Vehicles Certification Procedures],
- Z-2014-0819-06 [Proposed Amendments To The LEV III Criteria Pollutant Requirements For Light- And Medium-Duty Vehicles, The Hybrid Electric Vehicle Test Procedures, And The Heavy-Duty Otto-Cycle And Heavy-Duty Diesel Test Procedures],
- Z-2018-0724-07 [Proposed Amendments to the Low-Emission Vehicle III Greenhouse Gas Emission Regulation], and
- Z-2018-0821-02 [Amendments to California Specification for Fill Pipes and Openings Of Motor Vehicle Fuel Tanks].

Disclosure Regarding the Proposed Regulation

Fiscal Impact/Local Mandate Determination Regarding the Proposed Action (Gov. Code, § 11346.5, subds. (a)(5)&(6)):

The determinations of the Board's Executive Officer concerning the costs or savings incurred by public agencies and private parties and businesses in reasonable compliance with the proposed regulatory actions are presented below.

Under Government Code sections 11346.5, subdivision (a)(5) and 11346.5, subdivision (a)(6), the Executive Officer has determined that the proposed regulatory actions would not create costs or savings to any State agency, would not create costs or savings in federal funding to the State, would not create costs or mandates to any local agency or school district, whether or not reimbursable by the State under Government Code, title 2, division 4, part 7 (commencing with section 17500), or other nondiscretionary cost or savings to State or local agencies.

Cost to any Local Agency or School District Requiring Reimbursement under Gov. Code section 17500 et seq.:

The Emergency Vehicle Emissions Regulations proposal is not expected to result in a cost to any local agency or school district requiring reimbursement under Government Code section 17500 et seq. (state-mandated costs under California Constitution Article XIII B, section 6, i.e., “unfunded mandate”), where the proposal is clarifying that regulations that have been in place for years remain operative, in light of the unusual circumstances here, and manufacturers were planning to achieve, or already were achieving, compliance with more stringent standards..

Cost or Savings for State Agencies:

The Emergency Vehicle Emissions Regulations proposal is not expected to result in a change to fiscal impacts on state government, where the proposal is clarifying that regulations that have been in place for years remain operative in light of the unusual circumstances here, and manufacturers were planning to achieve, or already achieving, compliance with more stringent standards.

Other Non-Discretionary Costs or Savings on Local Agencies:

The Emergency Vehicle Emissions Regulations proposal is not expected to have non-discretionary costs or savings on local agencies, where the proposal is clarifying that regulations that have been in place for years remain operative in light of the unusual circumstances here, and manufacturers were planning to achieve, or already achieving, compliance with more stringent standards.

Cost or Savings in Federal Funding to the State:

The Emergency Vehicle Emissions Regulations proposal is not expected to impose any costs or savings in federal funding to the state.

Environmental Analysis

CARB, as the lead agency under the California Environmental Quality Act (CEQA), has reviewed the proposed Emergency Vehicle Emissions Regulation and concluded that it is exempt pursuant to CEQA Guidelines, section 15061(b)(3). The proposed regulatory action will provide clarity and confirm that, until a court resolves the uncertainty created by the federal government's actions, certain antecedent regulations (displaced by Advanced Clean Cars II and Omnibus) remain operative (as previously adopted) with the caveat that CARB may enforce Advanced Clean Cars II and Omnibus, to the extent permitted by law, in the event a court of law holds invalid the resolutions purporting to disapprove those waivers.

CARB has also determined this proposal is exempt pursuant to CEQA Guidelines sections 15307 (actions for protection of natural resources) and 15308 (actions for protection of the environment).

Agency Contact Persons

Inquiries concerning the substance of the proposal to make permanent CARB's Emergency Vehicle Emissions Regulations may be directed to the agency representative Michelle Buffington, Ph.D., Chief, Mobile Source Control Division, California Air Resources Board, (279) 208-7982 (VOIP), *Michelle.Buffington@arb.ca.gov*.

Availability of Documents

Copies of the emergency rulemaking documents, including the full text of the proposed regulatory language, in underline and strikeout format to allow for comparison with the existing regulations, and proposed new text, may be accessed on CARB's website listed below, on Monday, September 15, 2025. Please contact Lindsay Garcia, Regulations Coordinator, at *Regulations@arb.ca.gov* or (916) 546-2286 if you need physical copies of the documents. Pursuant to Government Code section 11346.5, subdivision (b), upon request to the Regulations Coordinator, physical copies would be obtained from the Public Information Office, California Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814.

Further, the agency representative to whom non-substantive inquiries concerning the proposed administrative action may be directed is Lindsay Garcia, Regulations Coordinator, (916) 546-2286. CARB staff has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

Internet Access

This Notice and the proposed regulatory text, and all subsequent regulatory documents, when completed, are available on CARB's website for this rulemaking at *https://ww2.arb.ca.gov/rulemaking/2025/emergencyvehemissions*

California Air Resources Board

Steven S. Cliff, Ph.D.,
Executive Officer

Date: September 15, 2025

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs, see *CARB's website* (ww2.arb.ca.gov).

APPENDIX A: Documents Incorporated by Reference

The Emergency Vehicle Emissions Regulations previously incorporated documents by reference as identified in OAL File Numbers:

- Z-00-1010-10 [Consider Requiring Certain California Light-and Medium-Duty Vehicles to be Subject to Federal Tier 2 Exhaust Standards, and Adopting Additional Exhaust Emission Standards for Heavy-Duty Gasoline Vehicles and Engines],
- Z-01-0828-14 [Amendments Adopting More Stringent Emission Standards for 2007 and Subsequent Model Year New Heavy-Duty Diesel Engines],
- Z-02-0917-02 [Consider the Incorporation of Federal Exhaust Emission Standards for 2008 and Later Model-Year Heavy-Duty Gasoline Engines and the Adoption of Minor Amendments to the Low-Emission Vehicle Regulations],
- Z-2011-1129-12 [Amendments To The California Greenhouse Gas And Criteria Pollutant Exhaust And Evaporative Emission Standards And Test Procedures And To The On-Board Diagnostic System Requirements For Passenger Cars, Light-Duty Trucks, And Medium-Duty Vehicles, And To The Evaporative Emission Requirements For Heavy-Duty Vehicles],
- Z-2012-0626-07 [Proposed Revisions to On-Board Diagnostic System Requirements for Heavy-Engines, Passenger Cars, Light-Duty Trucks, Medium-Duty Vehicles and Engines],
- Z-2012-0831-01 [Proposed Amendments To The New Passenger Motor Vehicle Greenhouse Gas Emission Standards For Model Years 2017-2025 To Permit Compliance Based On Federal Greenhouse Gas Emissions Standards And Additional Minor Revisions To The LEV III And ZEV Regulations],
- Z-2013-1015-07 [Proposed Greenhouse Gas (GHG) Regulations For Medium- And Heavy-Duty Engines And Vehicles, Optional Reduced Emission Standards For Heavy-Duty Engines, And Amendments To The Tractor-Trailer GHG Regulation, Diesel-Fueled Commercial Motor Vehicle Idling Rule, And The Heavy-Duty Hybrid-Electric Vehicles Certification Procedures],
- Z-2014-0819-06 [Proposed Amendments To The LEV III Criteria Pollutant Requirements For Light- And Medium-Duty Vehicles, The Hybrid Electric Vehicle Test Procedures, And The Heavy-Duty Otto-Cycle And Heavy-Duty Diesel Test Procedures],
- Z-2018-0724-07 [Proposed Amendments to the Low-Emission Vehicle III Greenhouse Gas Emission Regulation], and
- Z-2018-0821-02 [Amendments to California Specification for Fill Pipes and Openings Of Motor Vehicle Fuel Tanks].

The following documents are incorporated in the Emergency Vehicle Emissions regulatory action by reference as specified by the following sections of emergency regulations or by the original regulatory section in which they were adopted and are noted here for completeness.

- “California 2015 And Subsequent Model Criteria Pollutant Exhaust Emission Standards and Test Procedures And 2017 And Subsequent Model Greenhouse Gas Exhaust Emission Standards and Test Procedures For Passenger Cars, Light-Duty Trucks, And Medium-Duty Vehicles”, amended December 6, 2012, incorporated by reference in title 13, CCR, sections 1961.2.1, 1965.0.1, 2037.0.1, and 2038.0.1.

- “California Evaporative Emission Standards and Test Procedures For 2001 And Subsequent Model Motor Vehicles”, amended December 2012, incorporated by reference in title 13, CCR, section 1976.0.1.

- "California Refueling Emission Standards and Test Procedures For 2001 And Subsequent Model Motor Vehicles", amended March 22, 2012[Insert Date of Adoption], re-incorporated by reference to reflect new amended date in title 13, CCR, section 1978.0.1.
- "California Non-Methane Organic Gas Test Procedures for 2017 And Subsequent Model Year Vehicles", adopted September 2015, incorporated by reference in title 13, CCR, section 1961.2.1.
- "California Test Procedures For Evaluating Substitute Fuels and New Clean Fuels In 2015 and Subsequent Years" adopted March 2012, incorporated by reference in title 13, CCR, section 2317.0.1.
- "California Exhaust Emission Standards and Test Procedures For 2018 and Subsequent Model Zero-Emission Vehicles and Hybrid Electric Vehicles, In The Passenger Car, Light-Duty Truck And Medium-Duty Vehicle Classes", amended September 3, 2015**,** incorporated by reference in title 13, CCR, sections 1961.2.1 and 1962.2.1.
- "California Exhaust Emission Standards and Test Procedures For 2004 and Subsequent Model Heavy-Duty Diesel-Engines and Vehicles", amended October 21, 2014, incorporated by reference in title 13, CCR, section 1956.8.1(b).
- "California Exhaust Emission Standards and Test Procedures For 2004 and Subsequent Model Heavy-Duty Otto-Cycle Engines", amended October 21, 2014, incorporated by reference in title 13, CCR, section 1956.8.1(d).
- "California Greenhouse Gas Exhaust Emission Standards and Test Procedures for 2014 and Subsequent Model Heavy-Duty Vehicles", adopted October 21, 2014, incorporated by reference in title 17, CCR, section 95663(c).
- "California Interim Certification Procedures For 2004 and Subsequent Model Hybrid-Electric and Other Hybrid Vehicles in the Urban Bus and Heavy-Duty Vehicle Classes", amended October 21, 2014, incorporated by reference in title 13, CCR, section 1956.8.1(b).
- "California Non-Methane Organic Gas Test Procedures for 1993 Through 2016 Model Year Vehicles", amended September 2, 2015, incorporated by reference in title 13, CCR, section 1956.8.1(d).
- Society of Automotive Engineers (SAE) J1979 "E/E Diagnostic Test Modes," incorporated by reference in title 13, CCR, section 1968.2.1(c).
- SAE J1939 "Recommended Practice for a Serial Control and Communications Vehicle Network," incorporated by reference in title 13, CCR, section 1968.2.1(c).
- The evaporative emission standards and test procedures incorporated by reference in title 13, CCR, section 1976, as referenced in title 13, CCR, section 1968.2.1(c).
- The exhaust emission levels to which an engine family is certified under the averaging, banking, and trading program incorporated by reference in title 13, CCR, section 1956.8, as referenced in title 13, CCR, section 1968.2.1(c).
- The certification requirements and test procedures incorporated by reference in title 13, CCR, section 1961(d), as referenced in title 13, CCR, section 1968.2.1(c).

- The certification exhaust emission standards and test procedures applicable to the SET cycle incorporated by reference in title 13, CCR, section 1956.8(b) and section 1956.8(d), as referenced in title 13, CCR, section 1968.2.1(c).
- “Speed Versus Time Data for California’s Unified Driving Cycle”, dated December 12, 1996, incorporated by reference in title 13, CCR, section 1968.2.1(c).
- 40 CFR 86, Appendix 1, section (g) “EPA US06 Driving Schedule for Light-Duty Vehicles and Light-Duty Trucks,” amended July 13, 2005, incorporated by reference in title 13, CCR, section 1968.2.1(c).
- Air Resources Board (ARB) Manufacturers Advisory Correspondence (MAC) No. 99-06, adopted December 20, 1999, incorporated by reference in title 13, CCR, section 1968.2.1(e)(14.1.2)(A).
- SAE J1930 “Electrical/Electronic Systems Diagnostic Terms, Definitions, Abbreviations, and Acronyms – Equivalent to ISO/TR 15031-2:April 30, 2002”, incorporated by reference in title 13, CCR, section 1968.2.1(e)(14.1.2)(B).
- SAE J1930 “Electrical/Electronic Systems Diagnostic Terms, Definitions, Abbreviations, and Acronyms – Equivalent to ISO/TR 15031-2”, October 2008, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.1).
- SAE J1962 “Diagnostic Connector – Equivalent to ISO/DIS 15031-3:December 14, 2001”, April 2002, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.2).
- SAE J1978 "OBD II Scan Tool – Equivalent to ISO/DIS 15031-4:December 14, 2001", April 2002, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.3).
- SAE J1979 “E/E Diagnostic Test Modes”, May 2007, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.4).
- SAE J1979-DA, “Digital Annex of E/E Diagnostic Test Modes”, October 2011, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.4.1).
- SAE J1850 “Class B Data Communications Network Interface”, May 2001, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.5).
- SAE J2012 “Diagnostic Trouble Code Definitions – Equivalent to ISO/DIS 15031-6”, December 2007, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.6).
- ISO 9141-2:1994 “Road Vehicles-Diagnostic Systems-CARB Requirements for Interchange of Digital Information”, February 1994, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.7).
- ISO 14230-4:2000 “Road Vehicles-Diagnostic Systems-KWP 2000 Requirements for Emission-related Systems”, June 2000, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.8).
- ISO 15765-4:2005 “Road vehicles-Diagnostics on Controller Area Network (CAN) - Part 4: Requirements for emissions-related systems”, January 2005, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.9).
- SAE J1939 “Recommended Practice for a Serial Control and Communications Vehicle Network” March 2009, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.10.1).

- SAE J1939/1 “Recommended Practice for Control and Communications Network for On-Highway Equipment”, September 01, 2000, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.10.2).
- SAE J1939/11 “Physical Layer, 250K bits/s, Twisted Shielded Pair”, September 18, 2006, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.10.3).
- SAE J1939/13 “Off-Board Diagnostic Connector”, March 11, 2004, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.10.4).
- SAE J1939/15 “Reduced Physical Layer, 250K bits/sec, UN-Shielded Twisted Pair (UTP)”, August 21, 2008, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.10.5).
- SAE J1939/21 “Data Link Layer”, December 22, 2006, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.10.6).
- SAE J1939/31 “Network Layer”, April 02, 2004, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.10.7).
- SAE J1939/71 “Vehicle Application Layer (Through February 2008)”, January 20, 2009, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.10.8).
- SAE J1939/73 “Application Layer - Diagnostics”, September 08, 2006, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.10.9).
- SAE J1939/81 “Network Management”, May 08, 2003, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.10.10).
- SAE J1939/84 “OBD Communications Compliance Test Cases For Heavy Duty Components and Vehicles”, December 2008, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.10.11).
- SAE J1699-3 – “OBD II Compliance Test Cases”, May 2006, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.11).
- SAE J2534-1 – “Recommended Practice for Pass-Thru Vehicle Programming”, December 2004, incorporated by reference in title 13, CCR, section 1968.2.1(g)(1.12).
- Attachment E: CAL ID and CVN Data of ARB Mail-Out #MSC 06-23, December 21, 2006, incorporated by reference in title 13, CCR, section 1968.2.1(g)(4.7.4).
- Attachment A of ARB Mail-Out #95-20, May 22, 1995, incorporated by reference in title 13, CCR, section 1968.2.1(i)(2.2).
- Attachment A: Misfire Disablement and Detection Chart of ARB Mail-Out #06-23, December 21, 2006, incorporated by reference in title 13, CCR, section 1968.2.1(i)(2.5.1)(C).
- Attachments F and G of ARB Mail-Out #MSC 06-23, December 21, 2006, incorporated by reference in title 13, CCR, section 1968.2.1(i)(2.16).
- Attachment D: Rate Based Data of ARB Mail-Out #06-23, December 21, 2006, incorporated by reference in title 13, CCR, section 1968.2.1(j)(3.2).
- Health and Safety Code section 39010 et seq., incorporated by reference in title 13, CCR, section 1968.5.1(a)(3).

- Title 13, CCR, sections 1900(b) and 1968.2(c), incorporated by reference in title 13, CCR, section 1968.5.1(a)(3).
- EMFAC2000 “Public Meeting to Consider Approval of Revisions to the State’s On-Road Motor Vehicle Emissions Inventory: Technical Support Document, Section 7.1, ‘Estimation of Average Mileage Accrual Rates from Smog Check Data,’” May 2000, incorporated by reference in title 13, CCR, section 1968.5.1(b)(3)(A)(iv).
- SAE J1979 as incorporated by reference in title 13, CCR section 1968.2(g)(1) and section 1968.2.1(g)(4.1).
- SAE J1979 “E/E Diagnostic Test Modes,” February 2012, incorporated by reference in title 13, CCR, section 1971.1.1(c).
- The evaporative emission standards and test procedures incorporated by reference in title 13, CCR, section 1976, as referenced in title 13, CCR, section 1971.1.1(c).
- The exhaust emission levels to which an engine family is certified under the averaging, banking, and trading program incorporated by reference in title 13, CCR, section 1956.8, as referenced in title 13, CCR, section 1971.1.1(c).
- The certification exhaust emission standards and test procedures applicable to the SET cycle incorporated by reference in title 13, CCR, section 1956.8(b) and section 1956.8(d), as referenced in title 13, CCR, section 1971.1.1(c).
- SAE J1930 “Electrical/Electronic Systems Diagnostic Terms, Definitions, Abbreviations, and Acronyms – Equivalent to ISO/TR 15031-2”, October 2008, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.1).
- SAE J1930-DA “Electrical/Electronic Systems Diagnostic Terms, Definitions, Abbreviations, and Acronyms Web Tool Spreadsheet”, March 2012, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.1.1).
- SAE J1962 “Diagnostic Connector – Equivalent to ISO/DIS 15031-3:December 14, 2001”, April 2002, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.2).
- SAE J1978 “OBD II Scan Tool – Equivalent to ISO/DIS 15031-4:December 14, 2001”, April 2002, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.3).
- SAE J1979 “E/E Diagnostic Test Modes”, May 2007, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.4).
- SAE J1979-DA, “Digital Annex of E/E Diagnostic Test Modes”, October 2011, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.4.1).
- SAE J2012 "Diagnostic Trouble Code Definitions – Equivalent to ISO/DIS 15031-6", December 2007, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.5).
- SAE J2012-DA “Digital Annex of Diagnostic Trouble Code Definitions and Failure Type Byte Definitions”, July 2010, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.5.1).
- ISO 15765-4 “Road Vehicles-Diagnostics Communication over Controller Area Network (CAN) - Part 4: Requirements for emission-related systems”, February 2011, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.6).

- SAE J1939 “Recommended Practice for a Serial Control and Communications Vehicle Network”, April 2011, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.7.1).
- SAE J1939/1 “On-Highway Equipment Control and Communication Network”, May 2011, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.7.2).
- SAE J1939/11 “Physical Layer, 250K bits/s, Twisted Shielded Pair”, September 2006, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.7.3).
- SAE J1939/13 “Off-Board Diagnostic Connector”, October 2011, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.7.4).
- SAE J1939/15 “Reduced Physical Layer, 250K bits/sec, UN-Shielded Twisted Pair (UTP)”, August 2008, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.7.5).
- SAE J1939/21 “Data Link Layer”, December 2010, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.7.6).
- SAE J1939/31 “Network Layer”, May 2010, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.7.7).
- SAE J1939/71 “Vehicle Application Layer (Through May 2010)”, March 2011, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.7.8).
- SAE J1939/73 “Application Layer - Diagnostics”, February 2010, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.7.9).
- SAE J1939/81 “Network Management”, June 2011, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.7.10).
- SAE J1939/84 “OBD Communications Compliance Test Cases For Heavy Duty Components and Vehicles”, December 2010, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.7.11).
- SAE J2403 “Medium/Heavy-Duty E/E Systems Diagnosis Nomenclature,” February 2011, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.8).
- SAE J1699-3 – “OBD II Compliance Test Cases”, December 2009, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.9).
- SAE J2534-1 – “Recommended Practice for Pass-Thru Vehicle Programming”, December 2004, incorporated by reference in title 13, CCR, section 1971.1.1(h)(1.10).
- Attachment F of ARB Mail-Out #MSC 09-22, July 7, 2009, incorporated by reference in title 13, CCR, section 1971.1.1 (h)(4.7.6).
- Attachments G and H of ARB Mail-Out #MSC 09-22, July 7, 2009, incorporated by reference in title 13, CCR, section 1971.1.1 (j)(2.17).
- Health and Safety Code section 39010 et seq., incorporated by reference in title 13, CCR, section 1971.5.1(a)(3).
- Title 13, CCR, section 1900(b) and section 1971.1(c), incorporated by reference in title 13, CCR, section 1971.5.1(a)(3).

- EMFAC2007, incorporated by reference in title 13, CCR, section 1971.5.1(b)(3)(A)(iv).
- Society of Automotive Engineers J1979 (SAE J1979) or J1939 (SAE J1939) as incorporated by reference in Cal. Code Regs., title 13, section 1971.1.1(h)(1) and section 1971.1.1(h)(4.1).

Assembly Bill No. 1

CHAPTER 1

An act to amend Sections 25354.2, 25364, 25367, 25371, 25372.2, and 25373 of, to add and repeal Section 25354.4 of, and to add, repeal, and add Section 25354.6 of, the Public Resources Code, relating to energy.

[Approved by Governor October 14, 2024. Filed with Secretary of State October 14, 2024.]

LEGISLATIVE COUNSEL'S DIGEST

AB 1, Hart. Energy: transportation fuels: inventories: turnaround and maintenance.

Existing law, beginning on June 26, 2023, establishes the Independent Consumer Fuels Advisory Committee within the State Energy Resources Conservation and Development Commission (Energy Commission) to advise the Energy Commission and the Division of Petroleum Market Oversight, as provided. Existing law prescribes the composition of the 8-member committee, including 6 specified members appointed by the Governor, one member appointed by the Speaker of the Assembly, and one member appointed by the Senate Committee on Rules. Existing law requires one member appointed by the Governor to represent labor. Existing law prohibits a member of the committee from having been employed by, contracted with, or received direct compensation from, a company that produces, refines, distributes, trades in, markets, or sells any petroleum product in the preceding 12 months, except as provided. Existing law specifies that the schedule of meetings of the committee is to be prescribed by the Energy Commission.

This bill would specify that the above prohibition does not exclude a representative of a labor organization whose membership consists of, in whole or in part, individuals employed by a company that produces, refines, distributes, trades in, markets, or sells any petroleum product. The bill would require the gubernatorial appointee who represents labor to instead represent a labor organization with experience in refinery operations. The bill would require the committee to meet no less than annually.

Existing law requires the Energy Commission, in consultation with the Labor and Workforce Development Agency and labor and industry stakeholders, to consider ways to manage necessary refinery turnarounds and maintenance that would protect the health and safety of employees and the public, and minimize the impacts of maintenance-related production losses on fuel prices. Existing law authorizes the Energy Commission, by regulation, to impose requirements governing the timing of turnaround and maintenance.

This bill would expressly require those regulations to protect the health and safety of employees, local communities, and the public, and to include criteria that are required to be met before a refinery commences a turnaround or maintenance event, as provided.

This bill would require the Energy Commission, in consultation with the committee, to consider the effects of refiners' inventories of fuel and feedstocks and blending components on the price of transportation fuels in California. The bill would authorize the Energy Commission, by regulation, to develop and impose requirements for refiners operating in the state to maintain minimum levels of inventories of refined transportation fuels meeting California specifications, including any feedstocks and blending components, as specified. The bill would prohibit the Energy Commission from applying a minimum inventory requirement to a refiner in a manner that would be met only by the construction of additional storage infrastructure, as determined by the Energy Commission. The bill would repeal these provisions on January 1, 2033.

This bill would impose an administrative civil penalty on a refiner or person who fails to comply with regulations adopted pursuant to the above-described authority and would authorize the Energy Commission to seek any form of injunctive or remedial relief to enforce compliance with those regulations, as provided.

Existing law requires the Energy Commission, on or before January 1, 2024, and every 3 years thereafter, to submit an assessment to the Governor and the Legislature that, among other things, identifies methods to ensure a reliable supply of affordable and safe transportation fuels in California, as provided.

This bill, beginning with the first assessment submitted after the effective date of the bill, would require that the assessment also include an evaluation of California's future petroleum product and crude oil import needs, identification of steps that can be taken to ensure that marine infrastructure and port facilities will be adequate to accommodate the efficient movement of petroleum products to meet those needs, an evaluation of ways to maximize use of existing infrastructure and minimize cumulative pollution burdens, and an evaluation of the effects on supplies of transportation fuels of state regulations that the Energy Commission identifies may be causing supply constraints, or for which the Energy Commission believes alternative compliance pathways should be considered by state agencies to mitigate potential impacts on supply.

The people of the State of California do enact as follows:

SECTION 1. Section 25354.2 of the Public Resources Code is amended to read:

25354.2. (a) The commission, in consultation with the Labor and Workforce Development Agency and labor and industry stakeholders, shall consider ways to manage necessary refinery turnarounds and maintenance that would protect the health and safety of employees, local communities, and the public, and minimize the impact of maintenance-related production losses on fuel prices. The commission may, by regulation, impose requirements governing the timing of turnaround and maintenance developed through consultations under this section.

(b) Regulations adopted under this section shall do, but not be limited to, both of the following:

(1) Protect the health and safety of employees, local communities, and the public.

(2) Include criteria that are required to be met before a refinery commences a turnaround or maintenance event, including, but not limited to, demonstrating to the satisfaction of the executive director of the commission, through a report required by subdivision (m) of Section 25354, that the refiner has made resupply plans or other arrangements sufficient to ensure that the loss of production during the turnaround or maintenance event does not adversely affect the California transportation fuels market.

(c) This section does not modify any requirements of, or standards issued pursuant to, Section 6311 of, or Part 7.5 (commencing with Section 7850) of Division 5 of, the Labor Code, including the authority of employees to perform an emergency shutdown of the refinery and necessary maintenance work for safety.

(d) A regulation adopted, or action taken, pursuant to this section shall not excuse an employer's compliance with the skilled and trained workforce and wage requirements set forth in Section 25536.7 of the Health and Safety Code.

SEC. 2. Section 25354.4 is added to the Public Resources Code, to read:

25354.4. (a) The commission, in consultation with the Independent Consumer Fuels Advisory Committee established pursuant to Section 25373, shall consider the effects of refiners' inventories of fuel and feedstocks and blending components on the price of transportation fuels in California. The commission may, by regulation, develop and impose requirements for refiners operating in the state to maintain minimum levels of inventories of refined transportation fuels meeting California specifications, including any feedstocks and blending components for those fuels.

(b) Regulations adopted under this section shall protect the health and safety of employees, local communities, and the public, and shall provide for all of the following:

(1) A process for establishing minimum inventory levels specified for each refiner or each refining region, and for each fuel or blending component type.

(2) A process for maximizing the use of existing storage infrastructure.

(3) A process for waiving, if appropriate, minimum inventory requirements for a small refinery, as defined in Section 80.2 of Title 40 of the Code of Federal Regulations, as that section read on the effective date of the bill that added this section, if the refiner of the small refinery demonstrates that those requirements would impose a disproportionate economic hardship.

(4) A process for adjusting, if appropriate, minimum inventory requirements for one or more refiners based on region, season, refinery size

and storage capacity, and changes in regional or statewide supply and demand for refined transportation fuels meeting California specifications.

(5) Market conditions under which a refiner would be permitted or required to draw down its inventories below an established level and requirements for the rebuilding of those drawn-down inventories, including a metric or threshold based on market conditions that would automatically require a refiner to draw down inventories and provide that fuel to the market.

(c) Notwithstanding subdivision (a), the commission shall not adopt a regulation pursuant to this section unless it finds that the likely benefits to consumers from avoiding price volatility outweigh the potential costs to consumers. In making that determination, the commission shall consider all of the following factors, but no single factor shall be determinative:

(1) Whether it is likely that the minimum levels of inventories of refined transportation fuels will lead to greater supply in the California transportation fuels market than would exist without the minimum levels of inventories.

(2) Whether it is likely that the minimum levels of inventories of refined transportation fuels will lead to lower average retail prices on an annual basis than would exist without the minimum levels of inventories, and whether it is likely that the minimum levels of inventories will reduce the severity of retail price volatility.

(3) Whether easing of supply chain inefficiencies or constraints would lead to greater supply in the California transportation fuels market than requirements to establish minimum levels of inventories of refined transportation fuels.

(4) Whether it is likely that supply gains achieved through the adoption of the minimum levels of inventories of refined transportation fuels will be offset by actions of market participants not subject to these regulations and thereby have the effect of reducing supply in the market.

(d) (1) A regulation adopted under this section shall not modify any requirements of, or standards issued pursuant to, Section 6311 of, or Part 7.5 (commencing with Section 7850) of Division 5 of, the Labor Code, including the authority of employees to perform an emergency shutdown of the refinery and necessary maintenance work for safety.

(2) A regulation adopted, or action taken, pursuant to this section shall not excuse an employer's compliance with the skilled and trained workforce and wage requirements set forth in Section 25536.7 of the Health and Safety Code.

(e) In developing or amending regulations adopted under this section, the commission may consider the use of a compliance mechanism for each refiner that is tradable between or within each refining region for refiners to meet the minimum inventory requirements adopted pursuant to this section.

(f) The commission shall not apply a minimum inventory requirement under this section to a refiner in a manner that would be met only by the construction of additional storage infrastructure, as determined by the commission.

(g) One year after the adoption of any regulation pursuant to this section, and each year thereafter in which a regulation pursuant to this section is in effect, the commission shall submit a report to the Legislature, in accordance with Section 9795 of the Government Code, that includes a reevaluation of the effectiveness of that regulation, including whether the regulation continues to meet the cost effectiveness test described in subdivision (c), and shall provide an update on the factors identified in subdivision (c) regarding the implemented regulation.

(h) For purposes of this section, "refining region" means the two in-state regions of concentrated refineries, where the preponderance of refining capacity is located in the San Francisco Bay area and the Los Angeles area.

(i) This section shall remain in effect only until January 1, 2033, and as of that date is repealed.

SEC. 3. Section 25354.6 is added to the Public Resources Code, to read:

25354.6. (a) The commission shall notify a refiner or person who fails to comply with the requirements of Section 25354.2 or 25354.4, or fails to comply with the regulations adopted under those sections. If, within three days after being initially notified of the failure to comply, the refiner or person continues or persists in its noncompliance, the refiner or person shall be subject to an administrative civil penalty of not less than one hundred thousand dollars ($100,000), and not more than one million dollars ($1,000,000), per day for each day that the noncompliance occurs or persists.

(b) The executive director of the commission shall issue and serve a complaint on the refiner or person, and the commission shall hold a hearing, adopt a decision, and require payment of the penalty in accordance with the procedures described in Section 25534.1, with the penalty to be assessed based on each day of noncompliance following the third day after the initial notification by the commission.

(c) Judicial review and enforcement of an order imposing an administrative civil penalty under this section may be had in accordance with the procedures described in Section 25534.2.

(d) The commission may seek any form of injunctive or remedial relief from a court of competent jurisdiction to enforce compliance with Sections 25354.2 and 25354.4, and regulations adopted under those sections.

(e) This section shall remain in effect only until January 1, 2033, and as of that date is repealed.

SEC. 4. Section 25354.6 is added to the Public Resources Code, to read:

25354.6. (a) The commission shall notify a refiner or person who fails to comply with the requirements of Section 25354.2, or fails to comply with the regulations adopted under that section. If, within three days after being initially notified of the failure to comply, the refiner or person continues or persists in its noncompliance, the refiner or person shall be subject to an administrative civil penalty of not less than one hundred thousand dollars ($100,000), and not more than one million dollars ($1,000,000), per day for each day that the noncompliance occurs or persists.

(b) The executive director of the commission shall issue and serve a complaint on the refiner or person, and the commission shall hold a hearing, adopt a decision, and require payment of the penalty in accordance with the procedures described in Section 25534.1, with the penalty to be assessed based on each day of noncompliance following the third day after the initial notification by the commission.

(c) Judicial review and enforcement of an order imposing an administrative civil penalty under this section may be had in accordance with the procedures described in Section 25534.2.

(d) The commission may seek any form of injunctive or remedial relief from a court of competent jurisdiction to enforce compliance with Section 25354.2, and regulations adopted under that section.

(e) This section shall become operative on January 1, 2033.

SEC. 5. Section 25364 of the Public Resources Code is amended to read:

25364. (a) A person required to present information to the commission pursuant to Section 25354 or 25355 or a person making a request for exemption pursuant to Section 25355.5 may request that specific information be held in confidence. Information requested to be held in confidence shall be presumed to be confidential.

(b) Information presented to the commission pursuant to Section 25354, 25355, or 25355.5 shall be held in confidence by the commission or aggregated to the extent necessary to ensure confidentiality if public disclosure of the specific information or data would result in unfair competitive disadvantage to the person supplying the information or would adversely affect market competition.

(c) (1) Whenever the commission receives a request to publicly disclose unaggregated information, or otherwise proposes to publicly disclose information submitted pursuant to Section 25354, 25355, or 25355.5, notice of the request or proposal shall be provided to the person submitting the information. The notice shall indicate the form in which the information is to be released. Upon receipt of notice, the person submitting the information shall have 10 working days in which to respond to the notice to justify the claim of confidentiality on each specific item of information covered by the notice on the basis that public disclosure of the specific information would result in unfair competitive disadvantage to the person supplying the information or would adversely affect market competition.

(2) The commission shall consider the respondent's submittal in determining whether to publicly disclose the information submitted to it to which a claim of confidentiality is made. The commission shall issue a written decision that sets forth its reasons for making the determination whether each item of information for which a claim of confidentiality is made shall remain confidential or shall be publicly disclosed.

(d) The commission shall not make public disclosure of information submitted to it pursuant to Section 25354, 25355, or 25355.5 within 10 working days after the commission has issued its written decision required in this section.

(e) Information submitted to the commission pursuant to Section 25354, 25355, or 25355.5 shall not be deemed confidential if the person submitting the information or data has made it public.

(f) With respect to petroleum products and blendstocks reported by type pursuant to paragraph (1) or (2) of subdivision (a) of Section 25354, information provided pursuant to subdivision (h) or (i) of Section 25354, and information provided under Section 25355, the commission, the State Air Resources Board, or the Attorney General, or any employee or contractor of those entities, shall not do any of the following:

(1) Use the information furnished under paragraph (1) or (2) of subdivision (a) of Section 25354, under subdivision (h) or (i) of Section 25354, or under Section 25355 for any purpose other than law enforcement or the statistical purposes for which it is supplied.

(2) Make any publication whereby the information furnished by any particular establishment or individual under paragraph (1) or (2) of subdivision (a) of Section 25354, under subdivision (h) or (i) of Section 25354, or under Section 25355 can be identified.

(3) Permit anyone other than commission members, the State Air Resources Board, the Attorney General, and employees or contractors of those entities to examine the individual reports provided under paragraph (1) or (2) of subdivision (a) of Section 25354, under subdivision (h) or (i) of Section 25354, or under Section 25355.

(g) Notwithstanding any other law, the commission may disclose confidential information received pursuant to subdivision (a) of Section 25304, or Section 25354 or 25355 to the State Air Resources Board or the Attorney General if the state board or the Attorney General agrees to keep the information confidential. With respect to the information it receives, the state board and the Attorney General shall be subject to all pertinent provisions of this section.

(h) (1) Notwithstanding any other law, the commission shall, upon request, timely disclose confidential information received pursuant to subdivision (a) of Section 25304 or Section 25354 or 25355, or data provided under a contract entered into pursuant to Section 25367 or 25373, to the Speaker of the Assembly, the Senate Committee on Rules, the appropriate policy committees in the Assembly or the Senate, or staff members of each, provided that the information shall be provided only in aggregated or otherwise anonymized form, and each individual person receiving or having access to the information shall first agree, in writing, to keep the information confidential. Any person or committee receiving information under this subdivision shall be subject to all pertinent provisions of this section.

(2) Aggregated or otherwise anonymized information disclosed under paragraph (1) shall be made available by the commission to the public no more than quarterly, upon request of the Speaker of the Assembly, the Senate Committee on Rules, or the appropriate policy committees in the Assembly or the Senate, under conditions as the commission may determine are necessary to ensure that public disclosure of the specific information would not result in unfair competitive disadvantage to the person supplying the information or adversely affect market competition.

(i) Notwithstanding any other law, the commission may disclose confidential information received pursuant to paragraph (1) of subdivision

(f) of Section 25354 to the administrator for oil spill response, appointed pursuant to Section 8670.4 of the Government Code, upon request for oil spill planning and preparedness purposes, and to first responders in the event of an accident or spill. Information disclosed to the administrator or first responders pursuant to this subdivision that has been identified as confidential under subdivision (a) shall not be disclosed to any other entity except pursuant to a request in accordance with the California Public Records Act (Division 10 (commencing with Section 7920.000) of Title 1 of the Government Code). Upon receipt of a records request seeking information disclosed pursuant to this subdivision, the administrator or first responder receiving the request shall provide the destination facility who provided the confidential information to the commission with an opportunity to submit, within a reasonable time, a response and information in support of exemption from disclosure before making the determination whether the requested records are exempt from disclosure. A requirement or deadline contained in the California Public Records Act (Division 10 (commencing with Section 7920.000) of Title 1 of the Government Code) shall not be extended or waived as a result of this subdivision.

(j) This section does not apply to aggregate data that are required to be posted on the commission's internet website pursuant to subdivision (c) of Section 25355.

SEC. 6. Section 25367 of the Public Resources Code is amended to read:

25367. (a) Except as otherwise provided, the adoption of, or amendment to, regulations or orders implementing this chapter shall be considered by the Office of Administrative Law as an emergency, and necessary for the immediate preservation of the public peace, health, safety, and general welfare. Notwithstanding any other law, the emergency regulations or orders adopted to implement this chapter shall remain in effect for two years. Although the commission may adopt regulations to further define terms or prescribe reporting procedures or calculation methodologies pursuant to this chapter, or prescribe any other method of implementing this chapter, the provisions of this chapter are self-executing and shall not require any implementing regulation to be effective.

(b) The commission may enter into contracts to implement this chapter, and the contracts shall not require the review, consent, or approval of the Department of General Services or any other state department or agency and are not required to comply with requirements under the State Contracting Manual or the Public Contract Code.

(c) (1) Any regulation, guideline, other standard adopted, or decision rendered, by the commission under this chapter is not a "project" for purposes of the California Environmental Quality Act (Division 13 (commencing with Section 21000)). However, nothing in this section exempts any project undertaken pursuant to a regulation, guideline, other standard adopted, or decision rendered, pursuant to this chapter from the California Environmental Quality Act.

(2) This subdivision is declarative of existing law and shall apply to all regulations, guidelines, other standards adopted, or decisions rendered,

under this chapter whether before or after the effective date of this subdivision.

SEC. 7. Section 25371 of the Public Resources Code is amended to read:

25371. (a) (1) Notwithstanding Section 10231.5 of the Government Code, on or before January 1, 2024, and every three years thereafter, the commission shall submit an assessment to the Legislature, in accordance with Section 9795 of the Government Code, and to the Governor that does all of the following:

(A) Identifies methods to ensure a reliable supply of affordable and safe transportation fuels in California. The assessment shall include estimates for the level of transportation fuels at the state level, and, to the extent feasible, at regional and local levels, and individual refineries if relevant, that should be held in reserve by refiners to prevent gasoline price spikes. The assessment shall consider all factors causing price fluctuations in retail gasoline prices when recommending adequate reserve levels. The commission shall consider all relevant evidence from any reasonably available source, including, but not limited to, information about imports, by amount, source, if known, and data received by the commission pursuant to existing laws, economic and business experts, and information from any local, state, and federal agencies. The commission shall transmit to the Legislature, in accordance with Section 9795 of the Government Code, any proposals it deems appropriate for mandatory reserve levels and the terms of a program to implement reserve levels.

(B) Evaluates the price of transportation fuels, including branded and unbranded retail prices, alternate formulations of gasoline with lower carbon impact, and other products suitable for production from refineries in California. This evaluation shall consider the market demand for these products at 3-, 7-, 10-, and 20-year intervals from the date of the assessment and shall rely on the most recent transportation forecasting and assessment activities conducted pursuant to Section 25304. This evaluation shall include both of the following:

(i) An examination of whether branded fuel additives have any impact, and, if so, how much, on fuel efficiency and vehicle emissions.

(ii) An assessment of the presence and availability of retail outlets, including monitoring changes in availability of retail outlets that contribute to increasing retail prices in local and regional areas.

(C) Considers different levels of supply conditions and assesses the impact of potential refinery closures in California.

(D) Includes an analysis of the impacts on production of refinery planned maintenance, unplanned maintenance, and turnaround. The assessment shall evaluate ways to manage necessary maintenance among the various facilities that would protect the health and safety of employees and the public, and minimize the impact of maintenance-related production losses. Notwithstanding any other law, the Department of Industrial Relations and Division of Occupational Safety and Health shall disclose to the commission, upon request, any information the department and division have received under Section 7872 of the Labor Code to ensure all aspects of refinery safety are incorporated into the assessment. All information designated confidential shall be treated as confidential by the commission.

(E) Evaluates the utility and feasibility of alternative methods to maintain adequate supplies of transportation fuels, including delivery alternatives for fuel and components of refined fuel, such as delivery by rail, a publicly maintained strategic fuel reserve, and other solutions beyond the activities of refineries and petroleum market participants.

(F) Proposes solutions to mitigate any impacts described in the assessment. The solutions shall include an assessment of the employment impacts and the cost and cost-effectiveness of any proposal, including cost impacts to all impacted sectors, both public and private. The assessment shall include recommendations and alternatives.

(G) Beginning with the first assessment submitted after the effective date of this subparagraph, evaluates California's future petroleum product and crude oil import needs and identifies steps that can be taken to ensure that marine infrastructure and port facilities will be adequate to accommodate the efficient movement of petroleum products to meet those needs. In preparing the evaluation pursuant to this subparagraph, the commission shall consult with the ports in California at which petroleum and refined transportation fuels are imported, tanker terminal operators at California ports, the State Lands Commission, the California Coastal Commission, and the San Francisco Bay Conservation and Development Commission and evaluate ways to maximize the use of existing infrastructure and minimize cumulative pollution burdens.

(H) Beginning with the first assessment submitted after the effective date of this subparagraph, evaluates the effects of state regulations on supplies of transportation fuels that the commission identifies may be causing supply constraints, or for which the commission believes alternative compliance pathways should be considered by state agencies to mitigate potential impacts on supply.

(2) The first assessment shall include the evaluation of oil and gas extraction and refining that the State Air Resources Board outlined in the most recent update to the scoping plan prepared pursuant to Section 38561 of the Health and Safety Code.

(b) The assessment shall be separate from the report submitted pursuant to Section 25302 and shall be developed in a public process. The assessment shall be available to the public within the proceeding docket and shall be approved by a vote of the commission at its business meeting.

(c) The commission may enter into contracts to perform the assessment required by subdivision (a) and the contracts shall not require the review, consent, or approval of the Department of General Services or any other state department or agency and do not need to comply with requirements under the State Contracting Manual or the Public Contract Code.

(d) The Division of Petroleum Market Oversight shall provide input to and otherwise support other divisions of the commission in preparation of the assessment required by subdivision (a).

(e) The Independent Consumer Fuels Advisory Committee established pursuant to Section 25373 shall provide input to the commission in preparation of the assessment required by subdivision (a).

SEC. 8. Section 25372.2 of the Public Resources Code is amended to read:

25372.2. (a) The division shall do all of the following:

(1) Provide independent oversight and analysis of the transportation fuels markets for the protection of consumers by identifying market design flaws, market power abuses, and any other manner by which market participants act to harm competition or act contrary to the best interests of consumers in the state.

(2) Provide guidance and recommendations to the commission relating to the development of the assessment required by Section 25371 and the Transportation Fuels Transition Plan described in Section 25371.3.

(3) Provide guidance and recommendations to members of the commission, other divisions of the commission, and the California Department of Tax and Fee Administration relating to the reports described in Section 25355.7.

(4) Provide guidance and recommendations to the Governor, members of the commission, and other divisions of the commission on any other issues related to transportation fuels pricing and transportation decarbonization in California.

(5) Report its findings and recommendations to improve market performance at least annually to the Legislature, in accordance with Section 9795 of the Government Code, the Governor, the commission, the Attorney General, and the California Department of Tax and Fee Administration.

(b) (1) The division may subpoena witnesses, compel their attendance and testimony, administer oaths and affirmations, take evidence, and require by subpoena the production of any books, papers, records, or other items material to the performance of the division’s duties or exercise of its powers, including, but not limited to, current and historical pricing and sales data and contracts with other petroleum industry participants.

(2) With respect to the division, the director of the division is the “head of a department” for purposes of, and the division may undertake investigations in the manner described in, Article 2 (commencing with Section 11180) of Chapter 2 of Part 1 of Division 3 of Title 2 of the Government Code.

(c) The division may confidentially refer potential violations of law to the Attorney General at any time.

SEC. 9. Section 25373 of the Public Resources Code is amended to read:

25373. (a) The commission and division shall be advised by the Independent Consumer Fuels Advisory Committee, which is hereby established within the commission. The committee shall consist of the following members:

(1) Six members appointed by the Governor as follows:

(A) A member who holds an academic appointment and has knowledge of economics or business operations of the transportation fuels market.

(B) A member representing the California petroleum fuels industry.

(C) A member representing consumers.

(D) A member representing a labor organization with experience in refinery operations.

(E) A member with expertise in community, environmental, or environmental justice issues.

(F) A member with expertise in antitrust law.

(2) One member appointed by the Speaker of the Assembly.

(3) One member appointed by the Senate Committee on Rules.

(b) (1) Except for the member described in subparagraph (B) of paragraph (1) of, or subparagraph (D) of paragraph (1) of, subdivision (a), a member of the committee shall not have been employed by, contracted with, or received direct compensation from, a company that produces, refines, distributes, trades in, markets, or sells any petroleum product in the preceding 12 months.

(2) Except for the member described in subparagraph (B) of paragraph (1) of, or subparagraph (D) of paragraph (1) of, subdivision (a), before accepting appointment, members of the committee shall agree, in writing, not to be employed by, contract with, or receive direct compensation from companies described in paragraph (1) for the 12 months following the completion of their service on the committee.

(3) This subdivision shall not be construed to exclude a representative of a labor organization whose membership consists of, in whole or in part, individuals employed by a company that produces, refines, distributes, trades in, markets, or sells any petroleum product who otherwise meets the requirements of this section.

(c) Each member of the committee shall receive a per diem of one hundred dollars ($100) for each day actually spent in the discharge of official duties, and shall be reimbursed for traveling and other expenses necessarily incurred in the performance of official duties.

(d) The duties, organization, and schedule of meetings of the Independent Consumer Fuels Advisory Committee shall be prescribed by the commission, but shall meet no less than annually. The commission may delegate the authority under this subdivision to the executive director of the commission.

(e) The Independent Consumer Fuels Advisory Committee shall have access to aggregated or otherwise anonymized information submitted to the commission or to the division necessary to fulfill its duties under conditions as the commission determines necessary to ensure that any public disclosure of the specific information would not result in unfair competitive disadvantage to the person supplying the information or adversely affect market competition. The members of the committee shall also agree, in writing, to maintain the confidentiality of all information received.

(f) The executive director of the commission shall ensure that any confidential information shared with the members of the Independent

Consumer Fuels Advisory Committee is subject to a nondisclosure agreement and is maintained in a way that protects it from inadvertent disclosure.

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Market-based Policy Concepts Overview & Issues

Petroleum Market Advisory Committee Meeting

California Energy Commission

Sacramento, California

August 16, 2016

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Energy Assessments Division

California Energy Commission

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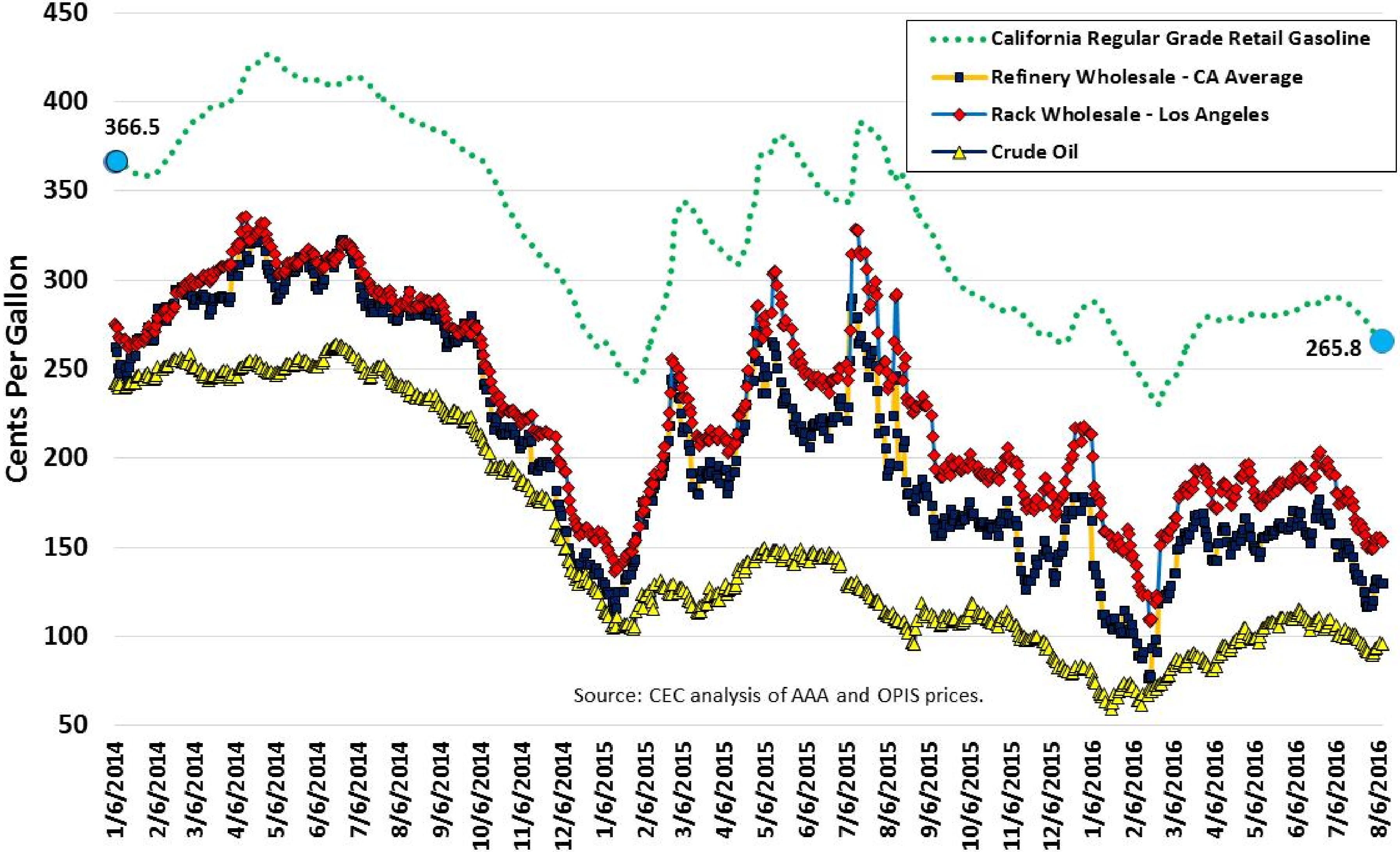
Overview

- Price spikes in California
  - Can be significant
  - Usually short-lived at refinery wholesale level (spot price)
  - Wholesale distribution terminal prices influenced by refinery spot
  - Retail prices influenced by distribution terminal prices
- Market-based policy concepts
  - Purpose to decrease magnitude of and/or duration of price spikes
- PMAC has proposed three preliminary concepts for discussion today
  - Price Pressure Relief Valve (PPRV)
  - Gasoline inventory requirements
  - Forward purchase of gasoline by state

California Gasoline Price Changes
Retail, Rack and Refinery Wholesale



Price Pressure Relief Valve (PPRV)

- Price pressure relief valve preliminary concept --
  - California would allow gasoline to be sold that meets only Federal Reformulated Gasoline (RFG) or conventional gasoline so long as the seller paid a surcharge to the state.
  - The surcharge would be set high enough, perhaps 25 cents per gallon, so that during normal supply/demand balances in the market for CARB gasoline there would be no incentive for a seller to utilize the non-CARB option.
  - The surcharge could be different for Federal RFG than for conventional gasoline.
  - Revenue from the surcharge could be used to offset any increased pollution from the use of non-CARB gasoline, such as by buying back older high-polluting cars.

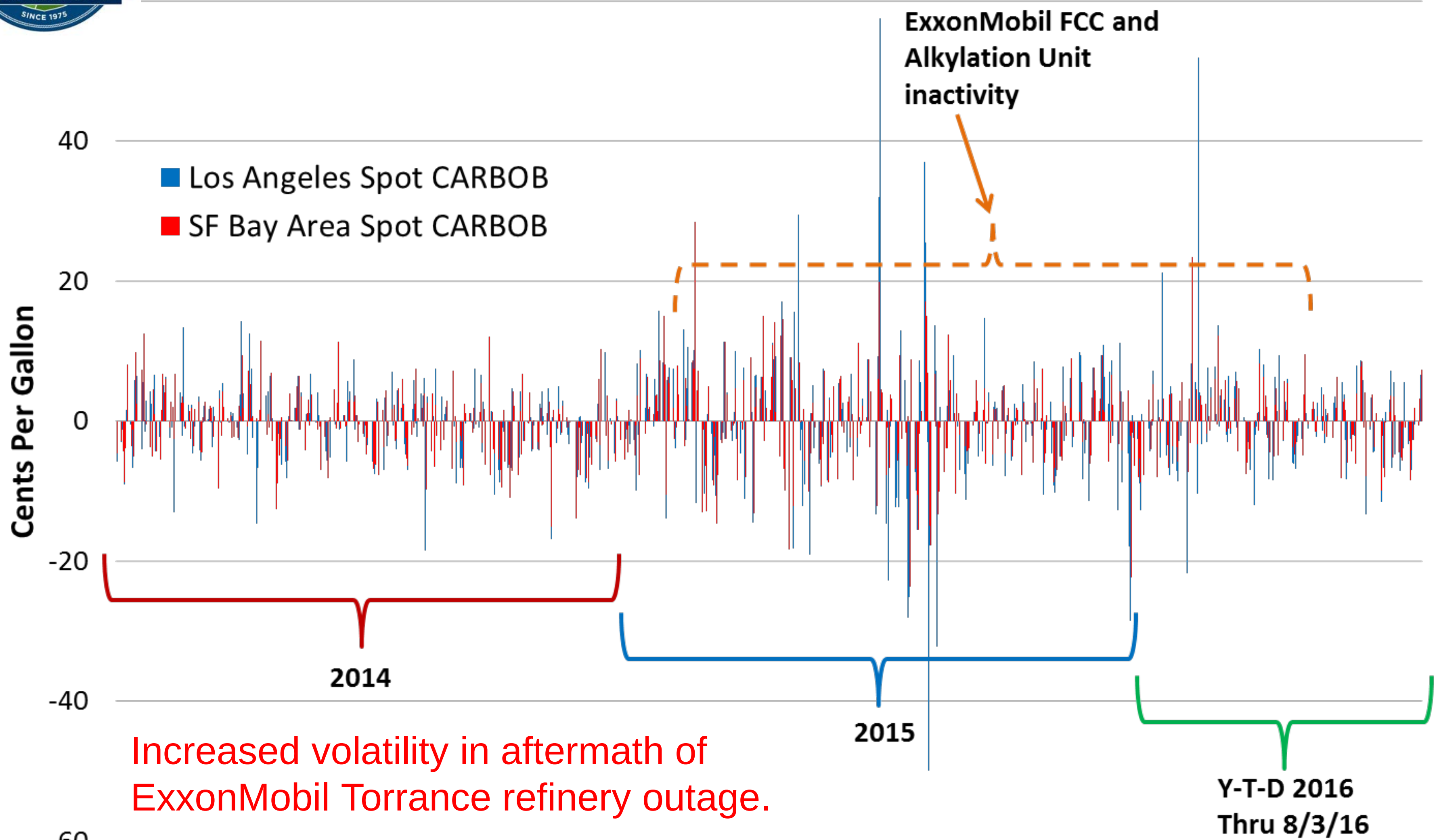
Price Pressure Relief Valve (PPRV)

- PPRV – Issues that should be examined
  - How quickly do refinery wholesale prices peak and decline?
  - How rapidly can gasoline supplies be delivered to California from outside the state?
  - What types of potential marine shipping limitations might exist?
  - How is gasoline usually distributed from refineries to retail stations?
  - What difficulties could be encountered by introducing non-complying gasoline into this distribution system?

Price Pressure Relief Valve (PPRV)

- PPRV – *How quickly do refinery wholesale prices peak and decline?*
  - Normally spot prices changes are less than 5 cpg between one business day and the next
    - 69 to 75 percent of time during 2014
    - 48 to 59 percent during 2015
    - 63 to 74 percent of time during Y-T-D 2016
  - Changes that were between 5 and 10 cpg
    - 21 to 26 percent of time during 2014
    - 28 to 32 percent during 2015
    - 24 to 28 percent of time during Y-T-D 2016
  - Changes that were greater than 10 cpg
    - 4 to 5 percent of time during 2014
    - 12 to 20 percent during 2015
    - 2 to 8 percent of time during Y-T-D 2016

Spot Gasoline Price Changes



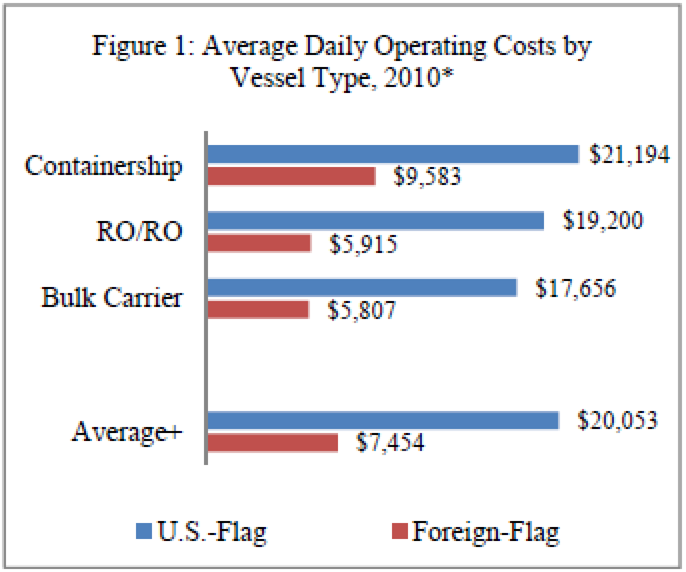
Sources: CEC analysis of Oil Price Information Service CARBOB prompt spot pipeline prices.

Price Pressure Relief Valve (PPRV)

- PPRV – *How rapidly can gasoline supplies be delivered to California from outside the state?*
  - Importation of non-California gasoline in response to a price spike requires a minimum amount of time to:
    - Identify a supply source – 1 day
    - Locate and arrange for a spot lease of a marine vessel – 1 to 2 days
    - Transit time for the vessel to arrive at the supply source – 1 to 3 days
    - Load the vessel with the non-California gasoline – 1 to 3 days
    - Transit time to a California marine terminal – 2 to 21 days
    - Discharge time for marine vessel – 1 to 3 days
    - ***Total combined time – 7 to 33 days – could be longer***
  - Most price spikes in the spot pipeline markets for gasoline peak and begin to recede within 7 days
    - Refinery wholesale price spike is usually over before a cargo can be delivered, damage is already done – spot increase has been passed along to wholesale rack and retail prices – importer at risk of losing money

Price Pressure Relief Valve (PPRV)

- PPRV – *What types of potential marine shipping limitations might exist?*
  - Movement of goods from one U.S. port to another U.S. port requires use of a Jones Act certified marine vessel
    - Vessel that is constructed, owned, operated, and crewed by U.S. entities
      - Nationwide, 51 Jones Act eligible tankers in service as of 5/31/16
    - Availability of these vessels is normally limited, especially along the West Coast
    - Cost of Jones Act vessels is normally greater than that of foreign-flagged tankers – at times significantly more expensive



*US-flag costs are weighted by the number of vessels in each operator's U.S.-flag fleet.
+Tanker costs omitted to protect operator confidentiality.

Figure Source: *Comparison of U.S. and Foreign-Flag Operating Costs*, US DOT Maritime Administration, September 2011, page 4.

Price Pressure Relief Valve (PPRV)

- PPRV – *How is gasoline usually distributed from refineries to retail stations?*
  - There are approximately 55 to 60 distribution terminals that are used to load tanker trucks prior to delivery to retail stations and card-lock facilities
  - Nearly all of these terminals are connected via petroleum product pipeline segments and systems that are either proprietary or common carrier status
  - Spare storage tankage is generally limited
  - Gasoline shipped through the pipeline distribution systems is first “created” in final shipment tanks by the mixing of several different types of gasoline blending components in specific ratios intended to comply with gasoline specifications and minimize production costs
  - This “base” gasoline is shipped to these distribution terminals where ethanol is introduced to the gasoline when tanker trucks are loaded

Price Pressure Relief Valve (PPRV)

- PPRV – *What difficulties could be encountered by introducing non-complying gasoline into this distribution system?*
  - The number and size of storage tanks at distribution terminals is based on the maximum quantity of petroleum product that is historically delivered to each location during a pipeline "cycle" that is between 7 to 8 days in length
  - At most distribution terminals, receipts of gasoline in the pipeline are directed to community storage tanks that contain deliveries from multiple refineries
    - Receipt of non-complying gasoline into these community storage tanks would contaminate the other gasolines
    - Ability to enforce gasoline regulations downstream of terminals would be compromised for all locations receiving gasoline from these contaminated community storage tanks
  - Could be similar problem for marine importing infrastructure – depending on nature of storage tank and interconnecting pipeline segments used to discharge cargoes of gasoline from marine vessels

Minimum Gasoline Inventory Holdings

- Inventory requirements for each fuel seller preliminary concept --
  - California would require every seller of CARB gasoline to hold inventory – either physically themselves or through legal control of inventory held by another entity – equal to X% of the seller's monthly average CARB sales volume, during normal supply times.
  - If the regulatory entity (i.e. the CEC) were to determine CARB gasoline prices are abnormally high, it could then temporarily reduce the inventory requirement, allowing additional supplies to be released into the market.

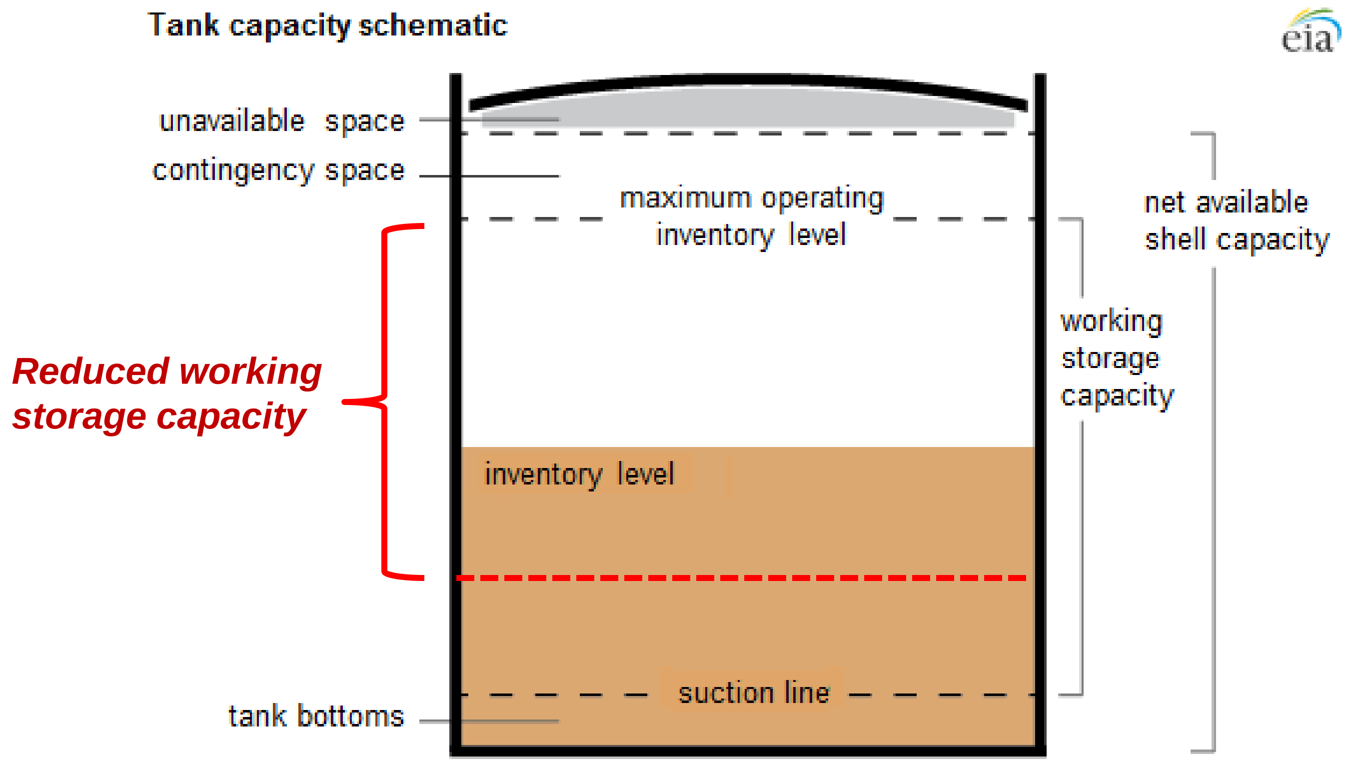
Minimum Gasoline Inventory Holdings

- Minimum Inventory – Issues that should be examined
  - How do refiners & other marketers use their storage tanks?
    - How might minimum inventory levels impact operations?
  - Reaction to requirement?
    - Reduction of strategic inventories by non-refiners?
    - Construction of new storage tanks?
  - What would be the trigger?
    - Specific or subjection "release" mechanisms?
  - Are there other "storage-related" concepts that should also be examined?

Minimum Gasoline Inventory Holdings

- Minimum Inventory – *How do refiners & other marketers use their storage tanks?*
  - Storage tanks associated with gasoline:
    - Gasoline blending components
    - Blending tanks
    - Strategic inventory – such as alkylate storage
      - Both refiners and non-refiners
    - Distribution terminals
      - Tanks cycle from full to empty and back with each pipeline delivery cycle

Minimum Gasoline Inventory Holdings



- Limiting the draw down level for current in-service storage tanks will decrease working storage capacity, impeding operational capability of refiners and marketers
  - How would the average market-clearing price of gasoline be impacted over the longer-term?

Minimum Gasoline Inventory Holdings

- Minimum Inventory – *Reaction to requirement?*
  - Reduction of strategic inventories by non-refiners is possible
    - Traders and other non-refiners hold strategic inventory of gasoline and/or components
    - Do not necessarily have ongoing contractual obligations to supply
    - These market participants provide at-hand gasoline inventory to sell to refiners during periods of unplanned outages
    - It is possible that some or most of these participants would exit the California market – which could impact availability of strategic gasoline supplies
  - Construction of new storage tankage
    - New tankage could be constructed in response to this concept
      - How much capacity might be constructed & where?
      - What are the costs and who would initially pay?

Minimum Gasoline Inventory Holdings

- Minimum Inventory – *What would be the trigger?*
  - Types of “release” mechanisms
    - Specific price increase
      - What price – rack, spot pipeline, average state retail?
      - What is the number and over what period of time?
    - Subjective release mechanism
      - If criteria for release is too vague or has any subjective language there could be additional uncertainty injected in the marketplace
  - After the “release”
    - How much time is allowed to refill minimum inventory obligation?
    - Where would resupply come from & how might that “phantom demand” impact the marketplace?
    - What is there is another temporary supply imbalance that triggers the mechanism prior to restocking of inventories?

Minimum Gasoline Inventory Holdings

- Minimum Inventory – *Are there other "storage-related" concepts that should also be examined?*
  - Should consider examination of other "storage-related" concepts
    - Construction of new storage tanks at end-of-pipeline distribution terminals
      - Contingency planning benefit during fuel shortages
    - Incentives designed to encourage construction of new storage tank capacity
      - What type
      - Locations
      - Quantity
      - Who pays

California Forward Purchase of Gasoline

- California forward purchase of gasoline to reduce import risk preliminary concept --
  - The state buys 1-2% of all CARB gasoline used in California. The state would contract with one or more sellers to deliver the gasoline needed by the state on a forward basis, with contracts signed 1-2 months ahead of delivery.
  - Such forward contracting could reduce the price risk that a fuel importer faces when arranging for delivery of CARB gasoline, which generally takes 1-2 months from the time of the order.
  - During times of abnormally high gasoline prices, the state might want to focus such contracting on sellers who would fulfill the contract by importing gasoline from out of state.

California Forward Purchase of Gasoline

- Forward Purchase – Issues that should be examined
  - What are the structure & duration of state fuel contracts?
    - Who are the current vendors of state gasoline contracts?
    - Are fuel supplies sourced by vendors from one or several locations?
    - How do typical gasoline import cargo volumes compare to state contract totals?
  - Has forward purchasing concept been previously assessed by the state?

California Forward Purchase of Gasoline

- *What are the structure & duration of state fuel contracts?*
  - Fuel cost is indexed to OPIS posted prices
  - Regions of state are linked to specific geographic terminal racks
    - Eureka, Sacramento, Fresno, Los Angeles, Barstow, and San Diego
  - Fuel prices also include charges for LCFS and CAR valuations
  - Differentials agreed to by winning vendors range between 0.5 and 7.6 cpg
  - Current fuel contracts are 3 years in length - 05/01/2014 through 04/30/2017

<u>Contract Cost Structure:</u>

GASOLINE, DIESEL #2, and ETHANOL (E-85) FUELS: The contract cost will be based on four (4) factors: Region Base Market Cost (RBMC), CAR Cost Fee, LCFS Cost Fee and the Differential Cost. The following formula outlines the contract price to be paid by the ordering agency:

REGION BASE MARKET PRICE	+	CAR COST FEE	+	LCFS COST FEE	+	DIFFERENTIAL	=	COMPOSITE PRICE
(Posted daily by the Contract Administrator using OPIS data)		(Posted daily by the Contract Administrator using OPIS data)		(Posted daily by the Contract Administrator using OPIS data)		(Provided by the Supplier)		

Source: Department of General Services (DGS), Contract Users Instructions, contract number 1-14-91-02-A, Supplement 6.

California Forward Purchase of Gasoline

- *Who are the current vendors of state gasoline contracts?*
  - Two vendors are current suppliers for gasoline under the state contract

FALCON FUELS

PINNACLE PETROLEUM, INC

  - Not refiners nor importers of marine cargoes
  - Vendors obtain gasoline from various distribution terminals as identified in DGS contracts – not a single location
  - Multiple California refiners are likely source of this gasoline
  - Typical import cargoes of gasoline are about 300,000 barrels – about 2 to 4 weeks-worth of total statewide gasoline contract volumes
  - But imports of gasoline are normally discharged in one port while DGS contracts require delivery to over 700 locations throughout the state

California Forward Purchase of Gasoline

- *Has forward purchasing concept been previously assessed by the state?*
  - Yes, findings published in April 2003 – CEC Draft Consultant Report P600-03-007D

State agencies weekly buy a quantity of gasoline (i.e., about one million gallons) on the order of one pipeline piece. An increase in volume of one piece per week would make some difference to the functioning of the forward market, since the daily volume is only a few pieces, but the state's trading would be unlikely to transform the market. In any case, because the state agencies need gasoline at many locations (and in small amounts), the state itself could not disperse one pipeline piece. Yet more problematic, all the state's procedures for procurement and inventory control exemplify the rigidity opposite to the flexibility needed for sophisticated trading in forward markets.

Source: "Price Spikes and Forward Markets for Gasoline", Jeffrey Williams and Jennifer Thompson

  - Are these conclusions still valid 13 years later?

Additional Questions?

Source: VisitCalifornia.com – Delta King and Tower Bridge over Sacramento River.

Senate Bill No. 237

CHAPTER 118

An act to amend Sections 8670.28 and 8670.37.51 of, and to add Section 51014.1 to, the Government Code, to add Section 43830.5 to the Health and Safety Code, and to amend Sections 25371 and 30262 of, to add Section 25371.4 to, and to add and repeal Section 21080.81 of, the Public Resources Code, relating to oil and gas.

[Approved by Governor September 19, 2025. Filed with Secretary of State September 19, 2025.]

LEGISLATIVE COUNSEL'S DIGEST

SB 237, Grayson. Oil spill prevention: gasoline specifications: suspension: California Environmental Quality Act: exemptions: County of Kern: transportation fuels assessment: coastal resources.

(1) The Lempert-Keene-Seastrand Oil Spill Prevention and Response Act generally requires the administrator for oil spill response, acting at the direction of the Governor, to implement activities relating to oil spill response, including emergency drills and preparedness, and oil spill containment and cleanup, and to represent the state in any coordinated response efforts with the federal government. Existing law requires the Governor to establish a California oil spill contingency plan that provides for an integrated and effective state procedure to combat the results of major oil spills within the state and that specifies state agencies to implement the plan. Existing law requires the administrator to adopt and implement regulations governing the adequacy of oil spill contingency plans to be prepared and implemented and requires the regulations to provide for the best achievable protection of coastal and marine waters. Existing law requires these regulations to permit the development, application, and use of an oil spill contingency plan for similar vessels, pipelines, terminals, and facilities within a single company or organization, and across companies and organizations. Existing law requires these regulations to ensure, among other things, standards for determining a reasonable worst case oil spill.

Under the act, the owner or operator of a facility where a spill could impact waters of the state is required apply for and obtain a certificate of financial responsibility issued by the administrator for the facility or the oil to be handled, stored, or transported by the facility.

This bill would require the administrator to publicly post a list of all applications for certificates of financial responsibility submitted by facility owners and operators on the internet website of the Office of Spill Prevention and Response and would require the posting to include specified information about applicants, including reasonable worst case spill volume of the facility to be covered by the certificate and the amount of financial responsibility demonstrated, as provided. This bill would, commencing January 15, 2027, and at least once every 10 years thereafter, require the administrator to solicit public input regarding both (A) the appropriateness of the reasonable worst case spill volumes for facilities and (B) the appropriateness of the financial responsibility requirements for facilities. The bill would require the supervisor, based on this feedback, to review and, as appropriate, revise the criteria and formulas for (A) calculating reasonable worst case spill volume and (B) calculating the financial assurances and setting the maximum amount of a certificate of financial responsibility necessary to respond to an oil spill, as provided.

(2) The Elder California Pipeline Safety Act of 1981 requires the State Fire Marshal to administer provisions regulating the inspection of intrastate pipelines used for the transportation of hazardous liquid. A violation of the act is a crime.

This bill would prohibit the restarting of an existing oil pipeline that is 6 inches or larger that has been idle, inactive, or out of service for 5 years or more without passing a spike hydrostatic testing program that meets the requirements established by the State Fire Marshal, as provided. By expanding the scope of a crime, the bill would impose a state-mandated local program. The bill would require these tests to be performed by a qualified testing company, as provided. The bill would require the Office of the State Fire Marshal to promulgate regulations as necessary to implement these provisions. The bill would require the State Fire Marshal to post on its public internet website information fully characterizing the parameters and results of each hydrostatic spike test performed, subject to any information deemed confidential and proprietary, no less than 30 calendar days after each hydrostatic spike test is conducted.

(3) Existing law authorizes the State Air Resources Board (state board) to adopt and implement motor vehicle fuel specifications for the control of air contaminants and sources of air pollution. Existing law requires the state board to establish, by regulation, maximum standards for the volatility of gasoline, as provided. Pursuant to these authorizations, the state board has adopted the California Reformulated Gasoline regulations establishing California-specific gasoline specifications for various regions of the state at specified time periods. Existing regulations also prohibit a person from selling, offering for sale, supplying, offering for supply, or transporting California gasoline that exceeds the applicable cap limit for Reid vapor pressure within each of specified air basins during various defined regulatory periods throughout the year.

This bill would require the Governor to suspend those regulatory control periods on which gasoline exceeding the Reid vapor pressure may be sold or supplied for use in the state, if the Governor, in consultation with the state board and the State Energy Resources Conservation and Development Commission, determines the average retail gasoline price increased substantially or is projected to increase substantially within any 30-day period and a suspension is necessary to protect consumers in the state from extraordinary gasoline price increases and determines, in the Governor's discretion, that suspension is prudent and unlikely to yield unintended consequences. The bill would require the Governor, in considering whether to suspend the regulatory control periods, to consider the air quality effects and options to mitigate those effects, if necessary and subject to available resources.

(4) Existing law requires the State Energy Resources Conservation and Development Commission (energy commission), on or before January 1, 2024, and every 3 years thereafter, to submit an assessment to the Governor and the Legislature that, among other things, identifies methods to ensure a reliable supply of affordable and safe transportation fuels in California and evaluates the price of transportation fuels, including branded and unbranded retail prices, alternate formulations of gasoline with lower carbon impact, and other products suitable for production from refineries in California, as provided.

This bill would require the next version of the above-described transportation fuels assessment to evaluate the cost and supply impacts of allowing the sale of gasoline with alternative specifications from the state board's gasoline specifications, as provided. The bill would require the energy commission to recommend a strategy to facilitate the sale of gasoline with those alternative specifications that, at a minimum, considers a trigger mechanism for when the gasoline with those alternative specifications may be sold, the existing variance process, and the use of a fee associated with the sale of the gasoline with those alternative specifications, as provided. The bill would additionally require the next version of this assessment to evaluate the development of westwide gasoline specification that could be used in a western region to include California and areas outside of California as an alternative to the California-specific specification in order to stabilize the petroleum market and petroleum prices in the western region, as provided. The bill would additionally require the energy commission, on or before March 31, 2026, to submit an assessment to the Governor and the Legislature that evaluates recommendations and strategies identified by the vice chair of the energy commission in a specified letter, and offers recommendations to the Legislature on potential changes to working group authorities or structures to support the state's reliable, equitable, safe, and affordable transition away from petroleum fuels.

(5) The California Environmental Quality Act (CEQA) requires a lead agency, as defined, to prepare, or cause to be prepared, and certify the completion of an environmental impact report on a project that it proposes to carry out or approve that may have a significant effect on the environment or to adopt a negative declaration if it finds that the project will not have that effect. CEQA also requires a lead agency to prepare a mitigated negative declaration for a project that may have a significant effect on the environment if revisions in the project would avoid or mitigate that effect and there is no substantial evidence that the project, as revised, would have a significant effect on the environment. CEQA prohibits a lead agency or a responsible agency from requiring the preparation of a subsequent or supplemental EIR unless one or more of 3 specified events occurs.

Existing law establishes the Geologic Energy Management Division in the Department of Conservation under the direction of the State Oil and Gas Supervisor, who is required to supervise the drilling, operation, maintenance, and abandonment of oil and gas wells in the state and the operation, maintenance, and removal or abandonment of tanks and facilities related to oil and gas production within an oil and gas field so as to prevent damage to life, health, property, and natural resources. Existing law requires the operator of a well to file a written notice of intention to commence drilling with, and prohibits any drilling until approval is given by, the supervisor or district deputy. Existing law prohibits the division from approving any notice of intention within a health protection zone, defined as the area within 3,200 feet of certain residential, educational, health care, detention, or business facilities, except approvals necessary for specified purposes. Existing law requires oil or gas production facilities or wells with a wellhead within a health protection zone to comply with specified health, safety, and environmental requirements, as provided.

This bill would, among other things, deem a specified County of Kern environmental impact report sufficient for full compliance with the requirements of CEQA for purposes of consideration and adoption of amended revisions to a specified County of Kern zoning ordinance, and would establish that this determination of full compliance shall be final and conclusive for purposes of reliance on that environmental impact report by any responsible agency, as provided. The bill would establish that projects that satisfy the requirements of that zoning ordinance and that are approved by the County of Kern under that ordinance are deemed sufficient for full compliance with CEQA and no further environmental review shall be required pursuant to CEQA. This bill would prospectively apply these provisions concerning CEQA compliance to any approvals by the County of Kern with respect to the permitting of oil and gas production operations under any adopted local ordinance and associated development. The bill would also apply these provisions prospectively and retroactively to any pending causes of action and claims for which no final nonappealable judgment has been entered, as provided.

The bill would prohibit the granting of approvals by the County of Kern or the Geologic Energy Management Division in reliance on that environmental impact report for any operation located in a health protection zone, regardless of whether the above-described prohibitions on health protection zones are enforceable. The bill would require the division to be the lead agency for projects in Kern County that include approval of a notice of intention to drill or rework an oil or gas well within 3,200 feet of specified types of buildings, to the extent such projects may be authorized by law. The bill would prohibit the division from approving more than 2,000 notices of intention to drill new wells in reliance on that environmental impact report as a responsible agency, unless the State Energy Resources Conservation and Development Commission makes a formal finding that additional permit issuance is necessary for in-state crude oil production to supply 25% of in-state refinery feedstock demand, and that such production would likely help reduce costs for retail consumers of gasoline in the state.

The bill would repeal all of the above-described provisions concerning CEQA in the County of Kern on January 1, 2036.

To the extent a lead agency would be required to determine the applicability of some of the above-described exemptions and determinations of full compliance with CEQA, the bill would impose a state-mandated local program.

(6) The California Coastal Act of 1976 requires a person wishing to perform or undertake any development in the coastal zone to obtain a coastal development permit. The act encourages coastal-dependent industrial facilities to locate or expand within existing sites and requires that facilities be permitted reasonable long-term growth, as provided. The act specifies that new or expanded oil and gas development is not to be considered a coastal-dependent industrial facility and is to be permitted only if it is consistent with the act and meets certain requirements, including a requirement that oil produced offshore is to be transported onshore by pipeline using the best achievable technology, as defined, and onshore transport of the oil to processing and refining facilities by pipeline. The act applies the pipeline requirements on new or expanded oil extraction operations, and defines terms for these purposes, including the term "expanded oil extraction." The act authorizes the transport of the oil by other modes of transportation if certain conditions are met.

This bill would require the onshore transportation of the oil to processing and refining facilities to use the best available technology, as provided. The bill would repeal authorization for the use of alternative modes of transportation. The bill would revise the definition of "expanded oil extraction" to include reactivation of a facility idled, inactive, or out of service for more than 5 years, or an increase in oil extraction from the use of hydraulic fracturing, extended reach drilling, acidization, or other unconventional technologies.

The act authorizes the repair and maintenance of an existing oil and gas facility to be permitted as a coastal-dependent industrial facility if certain requirements are met.

The bill would require a person to obtain a new coastal development permit for the repair, reactivation, and maintenance of an oil and gas facility, including an oil pipeline, that has been idled, inactive, or out of service for 5 years or more.

Because the bill would impose additional duties on a local government with a certified local coastal program in processing and reviewing an application for a coastal development permit, this bill would impose a state-mandated local program.

(7) Existing constitutional provisions require that a statute that limits the right of access to the meetings of public bodies or the writings of public officials and agencies be adopted with findings demonstrating the interest protected by the limitation and the need for protecting that interest.

This bill would make legislative findings to that effect.

(8) This bill would make legislative findings and declarations as to the necessity of a special statute for the County of Kern.

(9) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that with regard to certain mandates no reimbursement is required by this act for a specified reason.

With regard to any other mandates, this bill would provide that, if the Commission on State Mandates determines that the bill contains costs so mandated by the state, reimbursement for those costs shall be made pursuant to the statutory provisions noted above.

The people of the State of California do enact as follows:

SECTION 1. The Legislature finds and declares all of the following:

(a) In California, the success of the state's decarbonization strategies has moved the state's transportation sector from its early transition phase into the "mid-transition" phase, in which the state must simultaneously continue supporting the rapid expansion of a zero-emission and low-carbon transportation system while actively retiring the incumbent fossil fuel-based systems.

(b) A letter from the State Energy Resources Conservation and Development Commission to Governor Newsom, published in June 2025, recommended that the state, "Implement a suite of policies and programs to ensure environmental, public health, labor, economic, and consumer protections for a successfully managed transportation fuels transition […] Proactive planning and resources will be necessary to prepare communities for a future without petroleum industry, including refineries, and to ensure that fossil fuel-related legacies do not cause new harm."

(c) The state lacks explicit requirements for a refinery's closure or otherwise cessation of refining, despite the state now anticipating those closures.

(d) The state has an interest in understanding its potential financial liabilities. Absent any firm assurances to remediate these lands after a refinery's eventual closure, the obligations to fund cleanup are likely to fall upon the state and, by extension, the taxpayers, causing hundreds of prime acres to remain in disuse and leach hazardous waste or contaminants into surrounding communities for years.

(e) Refineries are major local employers and provide high-paying jobs to thousands of workers.

(f) Communities located near refineries and oil and gas extraction infrastructure bear the brunt of pollution in the state and have disproportionate negative health outcomes.

(g) The state should protect communities and assist workers in the transition through a holistic suite of policies to ensure the health and safety of the people of the State of California.

(h) It is the intent of the Legislature for the State Energy Resources Conservation and Development Commission to convene a working group that, at a minimum, includes representation from the State Air Resources Board, relevant local air districts, and any other state, local, or regional governmental entities that the commission deems appropriate to coordinate implementation of statutes, regulations, and additional authorities and provide recommendations to the Legislature on permitting changes and reforms to support the state's reliable, equitable, safe, and affordable transition away from petroleum fuels and the achievement of state climate and air quality goals and mandates.

(i) It is the intent of the Legislature to enact immediate measures to stabilize the transportation fuels market and to take future action to holistically address the mid-transition.

SEC. 2. Section 8670.28 of the Government Code is amended to read:

8670.28. (a) The administrator, taking into consideration the facility or vessel contingency plan requirements of the State Lands Commission, the Office of the State Fire Marshal, the California Coastal Commission, and other state and federal agencies, shall adopt and implement regulations governing the adequacy of oil spill contingency plans to be prepared and implemented under this article. All regulations shall be developed in consultation with the Oil Spill Technical Advisory Committee, and shall be consistent with the California oil spill contingency plan and not in conflict with the National Contingency Plan. The regulations shall provide for the best achievable protection of the waters and natural resources of the state. The regulations shall permit the development, application, and use of an oil spill contingency plan for similar vessels, pipelines, terminals, and facilities within a single company or organization, and across companies and organizations. The regulations shall, at a minimum, ensure all of the following:

(1) All areas of state waters are at all times protected by prevention, response, containment, and cleanup equipment and operations.

(2) Standards set for response, containment, and cleanup equipment and operations are maintained and regularly improved to protect the resources of the state.

(3) All appropriate personnel employed by operators required to have a contingency plan receive training in oil spill response and cleanup equipment usage and operations.

(4) Each oil spill contingency plan provides for appropriate financial or contractual arrangements for all necessary equipment and services for the response, containment, and cleanup of a reasonable worst case oil spill scenario for each area the plan addresses.

(5) Each oil spill contingency plan demonstrates that all protection measures are being taken to reduce the possibility of an oil spill occurring as a result of the operation of the facility or vessel. The protection measures shall include, but not be limited to, response to disabled vessels and identification of those measures taken to comply with requirements of Division 7.8 (commencing with Section 8750) of the Public Resources Code.

(6) Each oil spill contingency plan identifies the types of equipment that can be used, the location of the equipment, and the time taken to deliver the equipment.

(7) Each facility, as determined by the administrator, conducts a hazard and operability study to identify the hazards associated with the operation of the facility, including the use of the facility by vessels, due to operating error, equipment failure, and external events. For the hazards identified in the hazard and operability studies, the facility shall conduct an offsite consequence analysis that, for the most likely hazards, assumes pessimistic water and air dispersion and other adverse environmental conditions.

(8) Each oil spill contingency plan contains a list of contacts to call in the event of a drill, threatened discharge of oil, or discharge of oil.

(9) Each oil spill contingency plan identifies the measures to be taken to protect the recreational and environmentally sensitive areas that would be threatened by a reasonable worst case oil spill scenario.

(10) (A) Standards for determining a reasonable worst case oil spill.

(B) Commencing January 15, 2027, and at least once every 10 years thereafter, in order to increase public participation, the administrator shall solicit public input regarding the appropriateness of the reasonable worst case spill volumes for facilities. Based on this feedback, the administrator shall review and, as appropriate, revise the criteria and formulas for calculating reasonable worst case spill volumes to reflect the best available information. If revisions are appropriate, the administrator shall initiate a rulemaking action pursuant to the Administrative Procedure Act (Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3), which includes a public notice and comment process.

(C) Notwithstanding subparagraphs (A) and (B), for a nontank vessel, the reasonable worst case is a spill of the total volume of the largest fuel tank on the nontank vessel.

(11) Each oil spill contingency plan specifies an agent for service of process. The agent shall be located in this state.

(12) The review and potential subsequent rulemaking action pursuant to paragraph (10) shall be combined with and be used to inform the review and potential subsequent rulemaking action pursuant to paragraph (3) of subdivision (d) of Section 8670.37.51, related to financial responsibility.

(b) The regulations and guidelines adopted pursuant to this section shall also include provisions to provide for public review and comment on submitted oil spill contingency plans.

(c) The regulations adopted pursuant to this section shall specifically address the types of equipment that will be necessary, the maximum time that will be allowed for deployment, the maximum distance to cooperating response entities, the amounts of dispersant, and the maximum time required for application should the use of dispersants be approved. Upon a determination by the administrator that booming is appropriate at the site and necessary to provide best achievable protection, the regulations shall require that vessels engaged in lightering operations be boomed prior to the commencement of operations.

(d) The administrator shall adopt regulations and guidelines for oil spill contingency plans with regard to mobile transfer units, small marine fueling facilities, and vessels carrying oil as secondary cargo that acknowledge the reduced risk of damage from oil spills from those units, facilities, and vessels while maintaining the best achievable protection for the public health and safety and the environment.

SEC. 3. Section 8670.37.51 of the Government Code is amended to read:

8670.37.51. (a) A tank vessel or vessel carrying oil as a secondary cargo shall not be used to transport oil across waters of the state unless the owner or operator has applied for and obtained a certificate of financial responsibility issued by the administrator for that vessel or for the owner of all of the oil contained in and to be transferred to or from that vessel.

(b) An operator of a marine terminal within the state shall not transfer oil to or from a tank vessel or vessel carrying oil as a secondary cargo unless the operator of the marine terminal has received a copy of a certificate of financial responsibility issued by the administrator for the operator of that vessel or for all of the oil contained in and to be transferred to or from that vessel.

(c) An operator of a marine terminal within the state shall not transfer oil to or from any vessel that is or is intended to be used for transporting oil as cargo to or from a second vessel unless the operator of the marine terminal has first received a copy of a certificate of financial responsibility issued by the administrator for the person responsible for both the first and second vessels or all of the oil contained in both vessels, as well as all the oil to be transferred to or from both vessels.

(d) (1) An owner or operator of a facility where a spill could impact waters of the state shall apply for and obtain a certificate of financial responsibility issued by the administrator for the facility or the oil to be handled, stored, or transported by the facility.

(2) The administrator shall publicly post on the Office of Spill Prevention and Response internet website a list of all applications for certificates of financial responsibility submitted by facility owners and operators. The posting shall include the legal name of the applicant, the name and reasonable worst case spill volume of the facility to be covered by the certificate, the amount of financial responsibility demonstrated, and the type of evidence furnished to demonstrate the financial responsibility. The administrator shall post this information within seven business days of receiving an application.

(3) Commencing January 15, 2027, and at least once every 10 years thereafter, in order to increase public participation, the administrator shall solicit public input regarding the appropriateness of the financial responsibility requirements for facilities. Based on this feedback, the administrator shall review and, as appropriate, revise the criteria and formulas for calculating the financial assurances and setting the maximum amount of a certificate of financial responsibility necessary to respond to an oil spill to reflect the best available information, pursuant to the rulemaking requirements of the Administrative Procedure Act (Chapter 3.5

(commencing with Section 11340) of Part 1 of Division 3), which includes a public notice and comment process.

(e) Pursuant to Section 8670.37.58, nontank vessels shall obtain a certificate of financial responsibility.

SEC. 4. Section 51014.1 is added to the Government Code, to read:

51014.1. (a) Any existing oil pipeline that is six inches or larger that has been idle, inactive, or out of service for five years or more, shall not be restarted without passing a spike hydrostatic testing program.

(b) (1) (A) The hydrostatic spike test shall be at least 139 percent of the maximum operating pressure of the pipeline and shall not exceed 80 percent of the specific minimum yield strength, as determined appropriate by the State Fire Marshal.

(B) Notwithstanding subparagraph (A), at the operator's request, the minimum hydrostatic spike test pressure may be lower than 100 percent of the specified minimum yield strength if the maximum operating pressure of the pipeline is correspondingly reduced.

(i) Pursuant to this subparagraph the hydrostatic spike test shall be at least 139 percent of the reduced maximum operating pressure of the pipeline, as determined appropriate by the State Fire Marshal.

(ii) The hydrostatic spike test shall be performed in segments to ensure every elevation point is tested.

(2) If the specified minimum yield strength is unknown, the specified minimum yield strength shall be determined pursuant to Section 195.106(b) of Title 49 of the Code of Federal Regulations before performing the hydrostatic spike test.

(c) The hydrostatic spike test shall be no more than 15 minutes, and be immediately followed by a hydrostatic test, which shall be held for a minimum of eight hours and meet the requirements of the State Fire Marshal.

(d) The hydrostatic and hydrostatic spike test shall be performed in segments to ensure every elevation point is tested.

(e) All tests shall be performed by a qualified testing company that is compliant with this chapter, as determined by the State Fire Marshal.

(f) The Office of the State Fire Marshal shall promulgate regulations as necessary to implement this section.

(g) The requirements of this section shall become operative upon the effective date of this statute.

(h) The State Fire Marshal shall post on its public internet website information fully characterizing the parameters and results of each hydrostatic spike test performed, subject to any such information deemed confidential and proprietary, no less than 30 calendar days after each hydrostatic spike test is conducted pursuant to this section.

SEC. 5. Section 43830.5 is added to the Health and Safety Code, to read:

43830.5. Notwithstanding any other law, the Governor shall suspend the regulatory control periods under Section 2262.4 of Title 13 of the California Code of Regulations, during which gasoline exceeding the Reid vapor pressure limits in Title 13, Section 2262 of the California Code of Regulations may not be sold or supplied for use in the state, if the Governor, in consultation with the State Energy Resources Conservation and Development Commission and the state board, determines the average retail gasoline price increased substantially or is projected to increase substantially within any 30-day period and a suspension is necessary to protect consumers in the state from extraordinary gasoline price increases and determines, in the Governor's discretion, that suspension is prudent and unlikely to yield unintended consequences. In considering whether to suspend the regulatory control periods, as described in this section, the Governor shall consider the air quality effects and options to mitigate those effects, if necessary and subject to available resources.

SEC. 6. Section 21080.81 is added to the Public Resources Code, to read:

21080.81. (a) The Legislature finds and declares all of the following:

(1) The Legislature recognizes the significance of oil and gas production in the County of Kern, while also affirming the state's commitment to protecting public health, safety, and environmental quality, particularly for communities located near oil and gas operations.

(2) The County of Kern has adopted an oil and gas permitting ordinance, and in connection with that ordinance, has certified a Second Supplemental Environmental Impact Report (SSREIR) pursuant to this division. The County of Kern's SSREIR and oil and gas permitting ordinance impose comprehensive mitigations to address potential environmental impacts associated with oil and gas production.

(3) Article 4.6 (commencing with Section 3280) of Chapter 1 of Division 3 establishes health protection zones to safeguard residents from the health risks associated with oil and gas extraction activities. The Geologic Energy Management Division's approval of a notice of intention under Section 3203 is required before drilling a new oil and gas well. Section 3281 prohibits approval of a notice of intention within a health protection zone absent certain limited exceptions. The Kern County SSREIR does not cover activities within a health protection zone.

(4) Because the County of Kern's SSREIR does not cover activities within a health protection zone, the Geologic Energy Management Division is the lead agency under this division for projects that include permits to drill or rework an oil and gas well within a health protection zone in the County of Kern, to the extent that those activities might be allowed under Section 3281.

(b) The Kern County Second Supplemental Recirculated Environmental Impact Report (SCH2013081079), including all appendices (SSREIR March 2025), is hereby deemed sufficient for full compliance with this division for purposes of consideration and adoption of amended Revisions to Title 19 - Kern County Zoning Ordinance Code 2025 (A), Focused on Oil and Gas Local Permitting by the County of Kern. No further environmental review is required under this division for the consideration and adoption of the Revisions to Title 19 - Kern County Zoning Ordinance Code - 2025 (A), Focused on Oil and Gas Local Permitting (SSREIR March 2025), as enacted as of January 1, 2026. Corrections of minor typographical errors and formatting changes to the zoning ordinance version shall not require further environmental review. Any other modification to or readoption of the zoning ordinance, however, shall not be covered by this section but rather by the other provisions of this division.

(c) Projects that satisfy the requirements of Revisions to Title 19 - Kern County Zoning Ordinance Code - 2025 (A), Focused on Oil and Gas Local Permitting, and that are approved by the County of Kern under that ordinance as enacted as of the effective date of this section, or as reenacted to incorporate corrections of minor typographical errors or formatting changes, are deemed sufficient for full compliance with this division and no further environmental review is required under this division, so long as the projects comply with Article 4.6 (commencing with Section 3280) of Chapter 1 of Division 3, as that article read on January 1, 2025.

(d) This section applies prospectively to any approvals by the County of Kern with respect to the permitting of oil and gas production operations under any adopted local ordinance and associated development and also applies prospectively and retroactively to any causes of action and claims that are pending as of the effective date of this section, and for which no final nonappealable judgment has been entered before that date.

(e) Notwithstanding Section 21166, the Legislature's determination in this section that the Kern County Second Supplemental Recirculated Environmental Impact Report (SCH2013081079), including all appendices (SSREIR March 2025), is sufficient for full compliance with this division and shall be final and conclusive for purposes of reliance on that report for its use by any responsible agencies. Reliance on use of that report by any responsible agency shall fully satisfy the responsible agency's obligations under this division and shall not be subject to challenge pursuant to Section 21166.

(f) No approval may be granted by the County of Kern or the Geologic Energy Management Division in reliance on the Kern County Second Supplemental Recirculated Environmental Impact Report (SCH2013081079), including all appendices (SSREIR March 2025), with respect to any operation located in a health protection zone as defined in Section 3280, regardless of whether Section 3281 is enforceable or independently prohibits that approval.

(g) The Geologic Energy Management Division shall be the lead agency under this division for projects in the County of Kern that include approval of a notice of intention under Section 3203 to drill or rework an oil gas well within 3,200 feet of a residence, educational facility, youth center, health care facility, live-in housing, or any building housing a business that is open to the public, to the extent those projects may be authorized by law. The measurement shall be made from the property line unless the building is more than 50 feet set back from the property line, in which case the measurement shall be made from the outline of the building footprint to 3,200 feet in all directions.

(h) The Geologic Energy Management Division shall not approve more than 2,000 notices of intention per calendar year to drill new wells in reliance on the Second Supplemental Recirculated Environmental Impact Report (SCH2013081079) as a responsible agency under this section, unless the State Energy Resources Conservation and Development Commission makes a formal finding that additional permit issuance is necessary for in-state crude oil production to supply 25 percent of in-state refinery feedstock demand, and that the production would likely help reduce costs for retail consumers of gasoline in the state.

(i) Because the Kern County Second Supplemental Recirculated Environmental Impact Report (SCH2013081079), including all appendices (SSREIR March 2025), analyzes activities only through the end of 2035, further environmental review is required to satisfy the lead agency's obligations under this division for any County of Kern ordinance on oil and gas permitting enacted on or after January 1, 2026, unless that ordinance only corrects minor typographical errors and formatting to the zoning ordinance referenced in subdivision (b).

(j) This section shall remain in effect only until January 1, 2036, and as of that date is repealed, unless a later enacted statute that is enacted before January 1, 2036, deletes or extends that date.

SEC. 7. Section 25371 of the Public Resources Code is amended to read:

25371. (a) (1) Notwithstanding Section 10231.5 of the Government Code, on or before January 1, 2024, and every three years thereafter, the commission shall submit an assessment to the Legislature, in accordance with Section 9795 of the Government Code, and to the Governor that does all of the following:

(A) Identifies methods to ensure a reliable supply of affordable and safe transportation fuels in California. The assessment shall include estimates for the level of transportation fuels at the state level, and, to the extent feasible, at regional and local levels, and individual refineries if relevant, that should be held in reserve by refiners to prevent gasoline price spikes. The assessment shall consider all factors causing price fluctuations in retail gasoline prices when recommending adequate reserve levels. The commission shall consider all relevant evidence from any reasonably available source, including, but not limited to, information about imports, by amount, source, if known, and data received by the commission pursuant to existing laws, economic and business experts, and information from any local, state, and federal agencies. The commission shall transmit to the Legislature, in accordance with Section 9795 of the Government Code, any proposals it deems appropriate for mandatory reserve levels and the terms of a program to implement reserve levels.

(B) Evaluates the price of transportation fuels, including branded and unbranded retail prices, alternate formulations of gasoline with lower carbon impact, and other products suitable for production from refineries in California. This evaluation shall consider the market demand for these products at 3-, 7-, 10-, and 20-year intervals from the date of the assessment and shall rely on the most recent transportation forecasting and assessment activities conducted pursuant to Section 25304. This evaluation shall include both of the following:

(i) An examination of whether branded fuel additives have any impact, and, if so, how much, on fuel efficiency and vehicle emissions.

(ii) An assessment of the presence and availability of retail outlets, including monitoring changes in availability of retail outlets that contribute to increasing retail prices in local and regional areas.

(C) Considers different levels of supply conditions and assesses the impact of potential refinery closures in California.

(D) Includes an analysis of the impacts on production of refinery planned maintenance, unplanned maintenance, and turnaround. The assessment shall evaluate ways to manage necessary maintenance among the various facilities that would protect the health and safety of employees and the public, and minimize the impact of maintenance-related production losses. Notwithstanding any other law, the Department of Industrial Relations and Division of Occupational Safety and Health shall disclose to the commission, upon request, any information the department and division have received under Section 7872 of the Labor Code to ensure all aspects of refinery safety are incorporated into the assessment. All information designated confidential shall be treated as confidential by the commission.

(E) Evaluates the utility and feasibility of alternative methods to maintain adequate supplies of transportation fuels, including delivery alternatives for fuel and components of refined fuel, such as delivery by rail, a publicly maintained strategic fuel reserve, and other solutions beyond the activities of refineries and petroleum market participants.

(F) Proposes solutions to mitigate any impacts described in the assessment. The solutions shall include an assessment of the employment impacts and the cost and cost-effectiveness of any proposal, including cost impacts to all impacted sectors, both public and private. The assessment shall include recommendations and alternatives.

(G) Beginning with the first assessment submitted after the effective date of this subparagraph, evaluates California's future petroleum product and crude oil import needs and identifies steps that can be taken to ensure that marine infrastructure and port facilities will be adequate to accommodate the efficient movement of petroleum products to meet those needs. In preparing the evaluation pursuant to this subparagraph, the commission shall consult with the ports in California at which petroleum and refined transportation fuels are imported, tanker terminal operators at California ports, the State Lands Commission, the California Coastal Commission, and the San Francisco Bay Conservation and Development Commission and evaluate ways to maximize the use of existing infrastructure and minimize cumulative pollution burdens.

(H) Beginning with the first assessment submitted after the effective date of this subparagraph, evaluates the effects of state regulations on supplies of transportation fuels that the commission identifies may be causing supply constraints, or for which the commission believes alternative compliance pathways should be considered by state agencies to mitigate potential impacts on supply.

(I) In the first assessment submitted after the effective date of this subparagraph, evaluate the cost and supply impacts of allowing the sale of gasoline with alternative specifications from those in Subarticle 2 (commencing with Section 2260) of Article 1 of Chapter 5 of Division 3 of Title 13 of the California Code of Regulations to support a reliable and affordable supply of transportation fuels in California. If the evaluation finds that allowing the sale of gasoline with alternative specifications is likely to support a reliable and affordable supply of transportation fuels in California, the commission, in coordination with the State Air Resources Board, shall recommend a strategy to facilitate the sale of gasoline with those alternative specifications that, at a minimum, considers (i) a trigger mechanism for when the gasoline with those alternative specifications may be sold based on the conditions of the transportation fuels market, (ii) the existing variance process in Section 43013.2 of the Health and Safety code, and (iii) the use of a fee established pursuant to Section 43013.2 of the Health and Safety Code associated with the sale of gasoline with those alternative specifications to mitigate for any increase in emissions.

(J) (i) In the first assessment submitted after the effective date of this subparagraph, evaluate the development of a westwide gasoline specification that could be used in a western region to include California and areas outside of the state as an alternative to the California-specific specification established under Subarticle 2 (commencing with Section 2260) of Article 1 of Chapter 5 of Division 3 of Title 13 of the California Code of Regulations to stabilize the petroleum market and petroleum prices in the western region, including California. The commission, in coordination with the State Air Resources Board, shall conduct outreach to the western states, including the States of Arizona, Nevada, Oregon, and Washington, in furtherance of this evaluation.

(ii) The evaluation pursuant to this subparagraph shall assess the costs and benefits of each alternative specification, including economic impacts to the state and to consumers, labor impacts, public health impacts, and environmental impacts. In making this evaluation, the commission shall take into consideration the impacts of the state's electrification efforts and the requirements of the federal Clean Air Act (42 U.S.C. Sec. 7661 et seq.). The evaluation shall identify and recommend the alternative specification that would minimize the costs and maximize the benefits to the state.

(2) The first assessment shall include the evaluation of oil and gas extraction and refining that the State Air Resources Board outlined in the most recent update to the scoping plan prepared pursuant to Section 38561 of the Health and Safety Code.

(b) The assessment shall be separate from the report submitted pursuant to Section 25302 and shall be developed in a public process. The assessment shall be available to the public within the proceeding docket and shall be approved by a vote of the commission at its business meeting.

(c) The commission may enter into contracts to perform the assessment required by subdivision (a) and the contracts shall not require the review, consent, or approval of the Department of General Services or any other state department or agency and do not need to comply with requirements under the State Contracting Manual or the Public Contract Code.

(d) The Division of Petroleum Market Oversight shall provide input to and otherwise support other divisions of the commission in preparation of the assessment required by subdivision (a).

(e) The Independent Consumer Fuels Advisory Committee established pursuant to Section 25373 shall provide input to the commission in preparation of the assessment required by subdivision (a).

SEC. 8. Section 25371.4 is added to the Public Resources Code, immediately following Section 25371.3, to read:

25371.4. The commission shall, on or before March 31, 2026, submit an assessment to the Legislature, in accordance with Section 9795 of the Government Code, and to the Governor that evaluates the recommendations and strategies put forward by the vice chair of the commission in the June 27, 2025, letter to Governor Newsom in order to, as described in that letter, “ensure that Californians have access to safe, affordable, and reliable transportation fuels and that petroleum refiners continue to see value in serving the California market...” The assessment shall also offer recommendations to the Legislature and the Governor on potential changes to working group authorities or structures, including on permitting changes and reforms, which may include one-stop-shop permitting, to support the state’s reliable, equitable, safe, and affordable transition away from petroleum fuels.

SEC. 9. Section 30262 of the Public Resources Code is amended to read:

30262. (a) New or expanded oil and gas development shall not be considered a coastal-dependent industrial facility for the purposes of Section 30260, and may be permitted only if found to be consistent with all applicable provisions of this division and if all of the following conditions are met:

(1) The development is performed safely and consistent with the geologic conditions of the well site.

(2) Activities related to that development are consolidated, to the maximum extent feasible and legally permissible, unless consolidation will have adverse environmental consequences and will not significantly reduce the number of producing wells, support facilities, or sites required to produce the reservoir economically and with minimal environmental impacts.

(3) The development will not cause or contribute to subsidence hazards unless it is determined that adequate measures will be undertaken to prevent damage from that subsidence.

(4) All oilfield brines are reinjected into oil-producing zones unless the Geologic Energy Management Division of the Department of Conservation determines to do so would adversely affect production of the reservoirs and unless injection into other subsurface zones will reduce environmental risks. Exceptions to reinjections will be granted consistent with the California Ocean Plan of the State Water Resources Control Board and where adequate provision is made for the elimination of petroleum odors and water quality problems.

(5) (A) All oil produced offshore California shall be transported onshore by pipeline only. The pipelines used to transport this oil shall utilize the best achievable technology to ensure maximum protection of public health and safety and of the integrity and productivity of terrestrial and marine ecosystems.

(B) Once oil produced offshore California is onshore, it shall be transported to processing and refining facilities by pipeline that uses the best available technology pursuant to Section 51013.1 of the Government Code.

(C) The following guidelines shall be used when applying subparagraphs (A) and (B):

(i) "Best achievable technology," means the technology that provides the greatest degree of protection taking into consideration both of the following:

(I) Processes that are being developed, or could feasibly be developed, anywhere in the world, given overall reasonable expenditures on research and development.

(II) Processes that are currently in use anywhere in the world. This clause is not intended to create any conflicting or duplicative regulation of pipelines, including those governing the transportation of oil produced from onshore reserves.

(ii) "Oil" refers to crude oil before it is refined into products, including gasoline, bunker fuel, lubricants, and asphalt. Crude oil that is upgraded in quality through residue reduction or other means shall be transported as provided in subparagraphs (A) and (B).

(iii) Subparagraphs (A) and (B) shall apply only to new or expanded oil extraction operations. "New extraction operations" means production of offshore oil from leases that did not exist or had never produced oil, as of January 1, 2003, or from platforms, drilling islands, subsea completions, or onshore drilling sites, that did not exist as of January 1, 2003. "Expanded oil extraction" means an increase in the geographic extent of existing leases or units, including lease boundary adjustments, an increase in the number of well heads, reactivation of a facility idled, inactive, or out of service for more than five years, or an increase in oil extraction from the use of hydraulic fracturing, extended reach drilling, acidization, or other unconventional technologies, on or after January 1, 2003.

(6) If a state of emergency is declared by the Governor for an emergency that disrupts the transportation of oil by pipeline, oil may be transported by a waterborne vessel, if authorized by permit, in the same manner as required by emergency permits that are issued pursuant to Section 30624.

(7) In addition to all other measures that will maximize the protection of marine habitat and environmental quality, when an offshore well is abandoned, the best achievable technology shall be used.

(b) (1) Repair and maintenance of an existing oil and gas facility may be permitted in accordance with Section 30260 only if it does not result in expansion of capacity of the oil and gas facility, and if all applicable conditions of subdivision (a) are met.

(2) Repair, reactivation, and maintenance of an oil and gas facility, including an oil pipeline, that has been idled, inactive, or out of service for five years or more shall be considered a new or expanded development requiring a new coastal development permit consistent with this section.

(3) Development associated with the repair, reactivation, or maintenance of an oil pipeline that has been idled, inactive, or out of service for five years or more requires a new coastal development permit consistent with this section.

(4) The commission or local government with a certified local coastal program shall review and approve, modify, condition, or deny the permit based on the requirements of this section.

(c) Where appropriate, monitoring programs to record land surface and near-shore ocean floor movements shall be initiated in locations of new large-scale fluid extraction on land or near shore before operations begin and shall continue until surface conditions have stabilized. Costs of monitoring and mitigation programs shall be borne by liquid and gas extraction operators.

(d) This section does not affect the activities of any state agency that is responsible for regulating the extraction, production, or transport of oil and gas.

SEC. 10. The Legislature finds and declares that Section 4 of this act, which adds Section 51014.1 of the Government Code, imposes a limitation on the public's right of access to the meetings of public bodies or the writings of public officials and agencies within the meaning of Section 3 of Article I of the California Constitution. Pursuant to that constitutional provision, the Legislature makes the following findings to demonstrate the interest protected by this limitation and the need for protecting that interest:

The restrictions on information prescribed in Section 51014.1 of the Government Code are necessary to protect sensitive business information and trade secrets from public disclosure.

SEC. 11. The Legislature finds and declares that a special statute is necessary and that a general statute cannot be made applicable within the meaning of Section 16 of Article IV of the California Constitution because of the unique circumstances concerning the County of Kern's oil and gas permitting ordinance.

SEC. 12. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because a local agency or school district has the authority to levy service charges, fees, or assessments sufficient to pay for the program or level of service mandated by this act or because costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

However, if the Commission on State Mandates determines that this act contains other costs mandated by the state, reimbursement to local agencies and school districts for those costs shall be made pursuant to Part 7 (commencing with Section 17500) of Division 4 of Title 2 of the Government Code.

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Independent Statistics & Analysis
U.S. Energy Information Administration

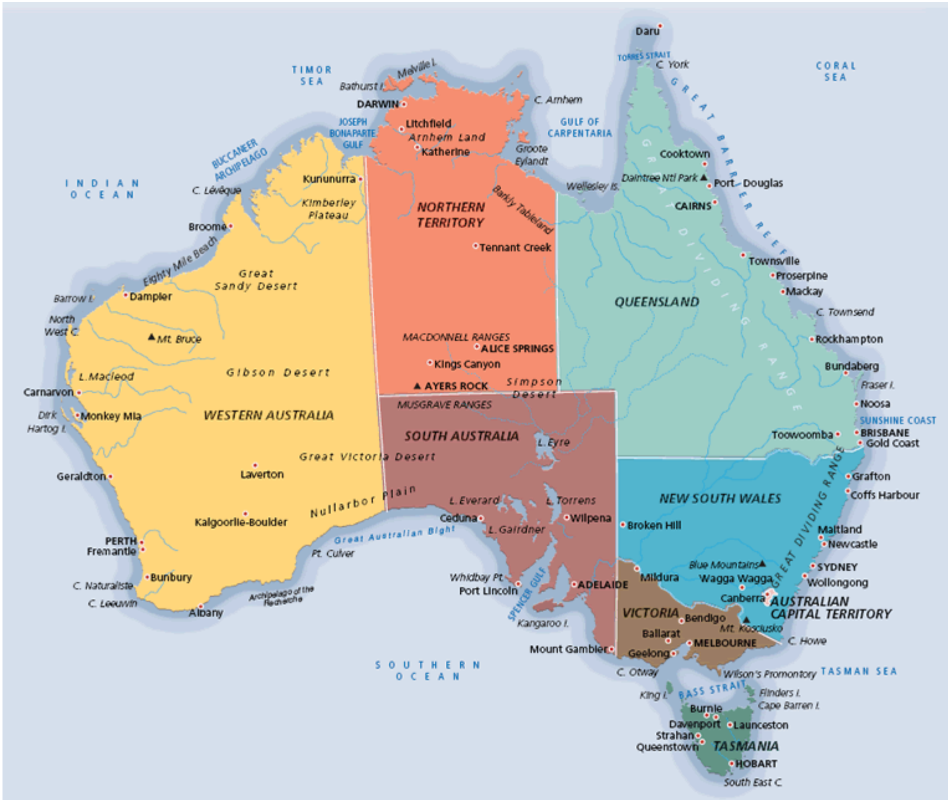
Country Analysis Executive Summary: Australia

Last Updated: March 18, 2022

Overview

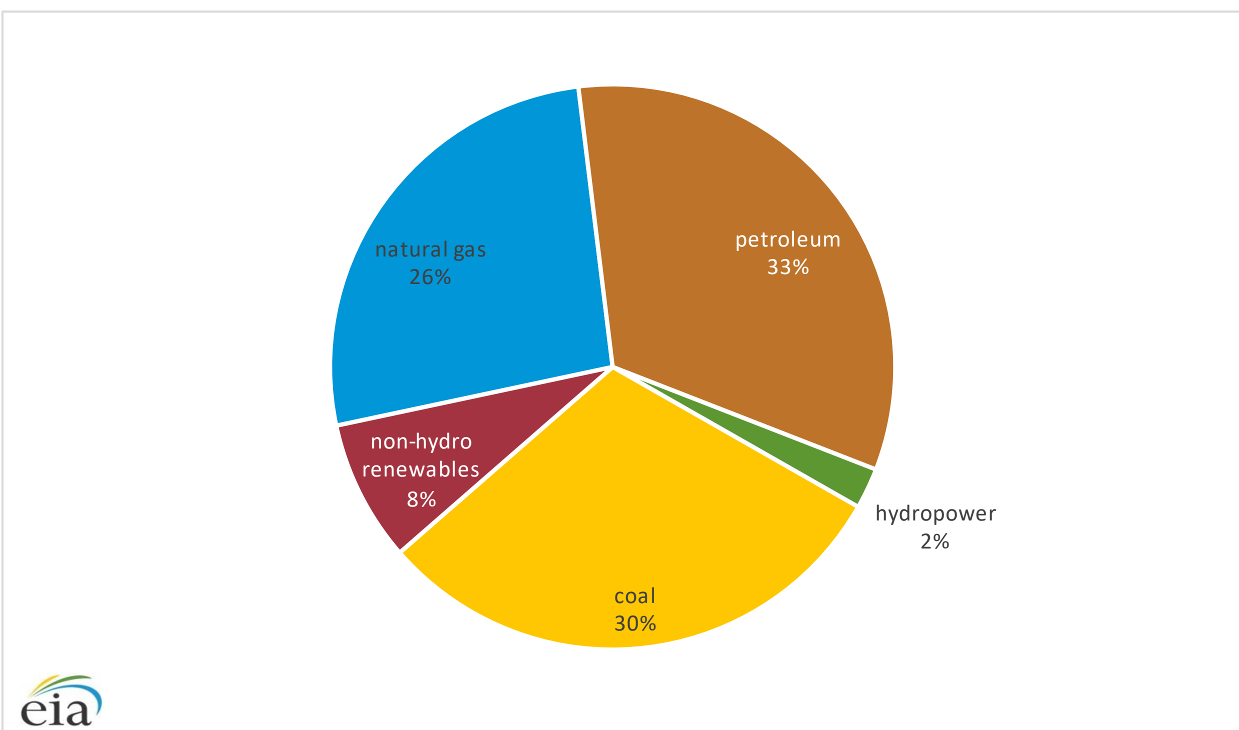
- Australia, a large producer of both coal and liquefied natural gas (LNG), exports the majority of its energy production. Australia's energy exports, excluding uranium, accounted for approximately 81% of its total energy production in 2020.[1]
- In 2020, Australia was the world's largest coal exporter based on energy content and the second-largest exporter based on weight, behind Indonesia. It was also the largest exporter of LNG in the world that year.
- Australia does not have any nuclear generation capacity, but it holds the largest uranium reserves in the world.[2] In 2020, it was the second-largest global uranium producer behind Kazakhstan.[3]
- In 2020, fossil fuels accounted for approximately 90% of Australia's total energy consumption; petroleum accounted for an estimated 33%, coal accounted for 30%, and natural gas accounted for 26% (Figure 2). The shares for petroleum and coal both decreased in 2020, accounting for the 2% drop in fossil fuel's overall share of energy consumption from 2019.[4]
- Renewable sources, including hydroelectricity, wind, and solar, accounted for 10% of total consumption in 2020. The growth in renewables has been driving the decrease in coal consumption.[5]

Figure 1. Map of Australia



Source: University of Nebraska, Omaha

Figure 2. Total primary energy consumption in Australia by fuel type, 2020

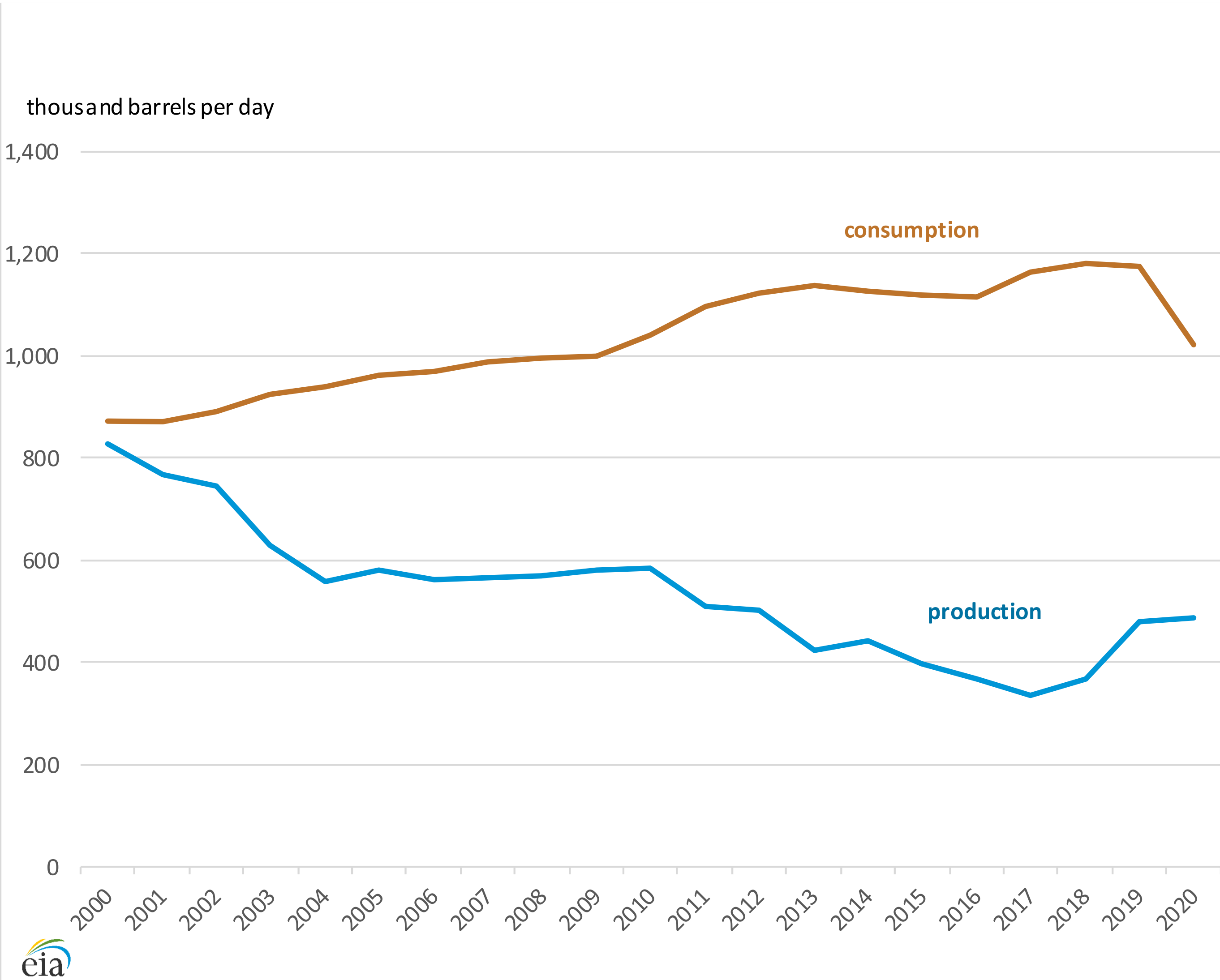


Source: Graph by the U.S. Energy Information Administration, based on data from BP Statistical Review of World Energy 2021

Petroleum and Other Liquids

- Australia's proved oil reserves were 2.4 billion barrels at the end of 2021.[6] Most of their reserves are located off the coasts of the states of Western Australia (Carnarvon and Browse basins), Victoria (Gipplsand basin), and the Northern Terrirtory (Bonaparte basin).
- Although Australia has significant undiscovered unconventional oil resources, exploration for these resources is still too early in its stages to assess the production potential.[7]

Figure 3. Australia's petroleum and other liquids production and consumption, 2000–2020



Source: Graph by the U.S. Energy Information Administration, *Short-Term Energy Outlook,* December 2021

Exploration and production

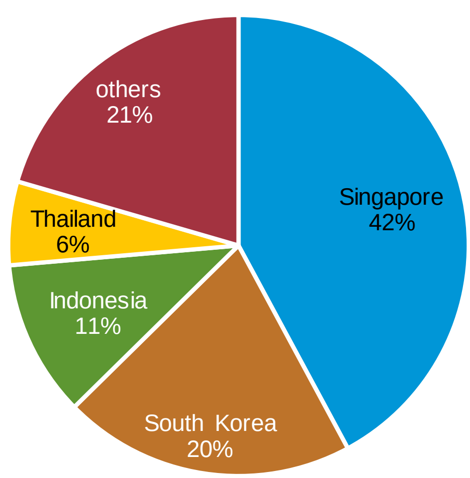
- Australia's petroleum and other liquids production, which includes crude oil, condensates, natural gas liquids, and refining gain, peaked at 828,000 barrels per day (b/d) in 2000. Production fell from its peak in 2000 because new development projects had not been able to offset production declines in mature fields.[8] After overall declining through 2017, production started to increase in 2018. Petroleum and other liquids production increased from 336,000 b/d in 2017 to an estimated 475,000 b/d in 2020 (Figure 3).[9]

- Petroleum and other liquids production was approximately 461,000 b/d in 2021, of which 26% was crude oil, 46% condensates, and 24% natural gas liquids. The remaining 4% were other liquids and refining gain.[10]
- New projects coming online in the North West Shelf are partly driving the increased production of crude oil and condensate. In 2018, projects in the Northern Carnarvon Basin and Browse Basin increased oil and condensates production by 18% and increased natural gas liquids production by 32%, compared with 2017.[11]
- The Greater Enfield project in Northern Carnavon was approved in 2016 and started production in 2019. The project consists of 12 development fields, and it adds approximately 41,000 b/d of production plus reserves of 69 million barrels of oil equivalent (BOE).[12]
- The Prelude floating LNG project in the Browse Basin started production at the end of 2018. Although the majority of its production is natural gas, it produces 47,600 b/d of condensate and 12,700 b/d of liquefied petroleum gas (LPG).[13] The Ichthys Field, also located in the Browse Basin, started production in 2018. According to the project's largest interest holder Inpex Corp., it has a production capacity of 48,000 b/d of LPG and 100,000 b/d of condensate.[14]
- Australia does not have any new projects coming online for a few years. The earliest is the Barossa Project, which Santos expects to come online in 2025.[15] We expect that Australia's petroleum production will remain relatively unchanged through 2023.

Consumption

- Australia has consumed more petroleum and other liquids than it has domestically produced for several decades. In 2020, consumption exceeded production by 547,000 b/d.[16]
- Australia's petroleum consumption decreased in 2020 to slightly more than 1 million b/d from 1.2 million b/d in 2019.[17] This decrease resulted from the drop in passenger and air transportation at the start of the global COVID-19 pandemic.[18] In 2020, the share of petroleum relative to total energy consumed in Australia fell by 3%.

Figure 4. Australia's crude oil and condensate exports by destination, 2021

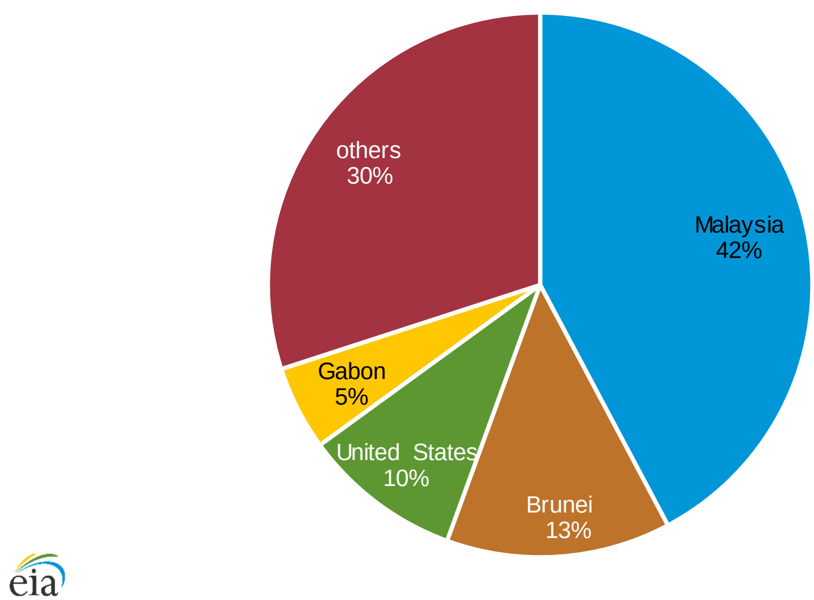


Source: Graph by the U.S. Energy Information Administration, based on data from ClipperData, LLC

Trade

- Australia became a net exporter of crude oil in 2020 for the first time since 1991 when their exports totaled 252,000 b/d and exceeded imports (237,000 b/d) by 15,000 b/d.[19] Crude oil imports decreased because of reduced demand in both 2020 and 2021. In 2021 imports decreased by 23% from 2020, this is a decline of 58,000 b/d.
- Australia has historically imported oil and refined petroleum product because consumption tends to be higher than domestic production. The country produces mainly light, sweet crude oil, which needs to be blended with heavy crude oils before it can be processed. Because oil production happens mostly on the North West Shelf, it is more cost effective to export crude oil and import petroleum products than to ship the oil to refineries on Australia's eastern coast.[20]
- Australia's crude oil exports were destined mainly for the Asia-Pacific region; Singapore (42%), South Korea (20%), Indonesia (11%), and Thailand (6%) received the most volumes in 2021 (Figure 4).[21]
- Australia's crude oil imports came mainly from Malaysia (42%) and Brunei (13%) in 2021 (Figure 5).[22]

Figure 5. Australia's crude oil and condensate imports by source, 2021



Source: Graph by the U.S. Energy Information Administration, based on data from ClipperData, LLC

Refining

- Australia had two refineries as of August 2021, with a total refining capacity of 229,000 b/d, operated by the Vitol Group and Ampol Ltd (Table 1).[23] The Altona refinery, operated by ExxonMobil, started it's decommission in early 2021 and shutdown in August. The facility is being converted into the Mobil Melbourne Terminal, which will be one of the largest fuel import and storage facilities in Australia.[24]

- Since 2013, five refineries, with a total capacity of 557,000 b/d, closed in Australia (Table 2).
- Refinery runs decreased by 68,000 b/d in 2021 because the Kwinana refinery closed[25] in March[26] and the Altona refinery closed in August.[27] With these closures, refinery capacity in Australia has decreased by 570,000 b/d since 2013.[28]
- Australia passed the Fuel Security Bill in June of 2021. The bill provides approximately US $1.8 billion in funding to keep the two remaining refineries operational until 2027.[29] The bill provides funds for refinery upgrades as well as production payments for refiners making specific types of transport fuel when margins drop below AU $7.30 a barrel.[30]

Table 1. Oil refineries in Australia, 2021

Refinery	Nameplate refining capacity (thousand barrels per day)
Lytton	109
Geelong	120
Total	**229**

Source: Table by the U.S. Energy Information Administration, based on data from BP Statistics and Reuters

Table 2. Australia's oil refineries that have closed since 2013

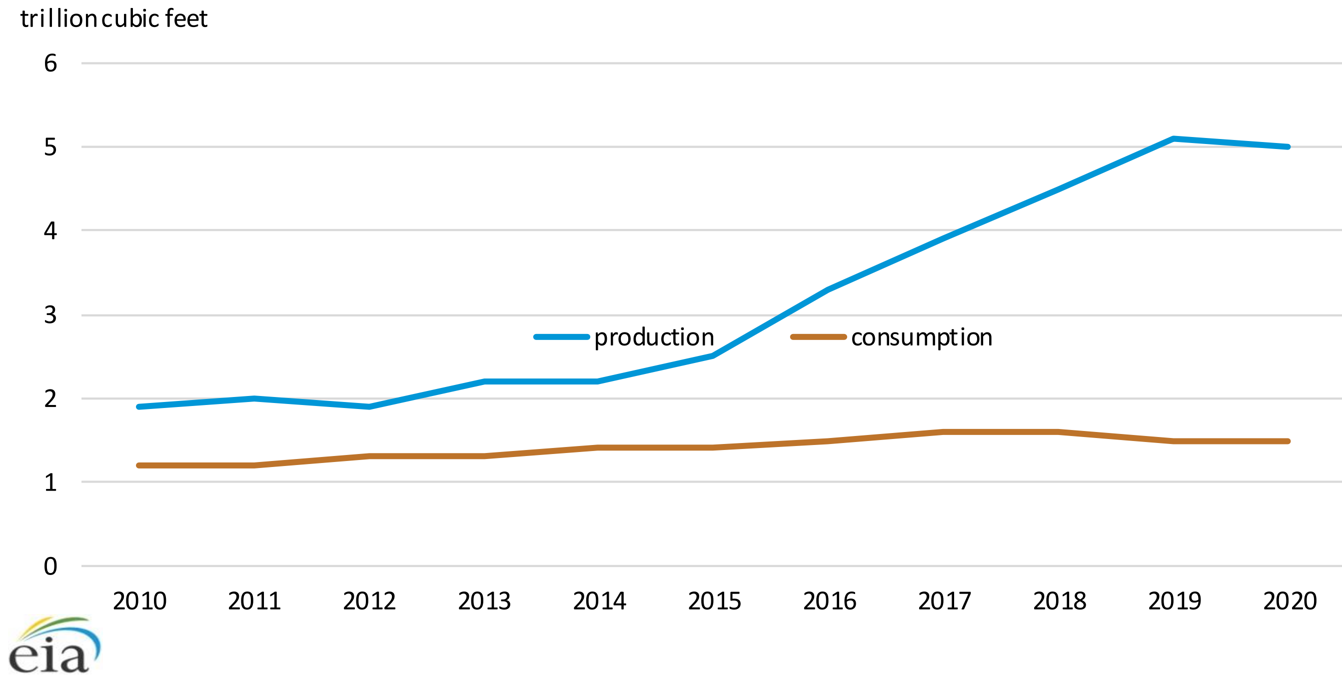
Refinery	Capacity (thousand barrels per day)	Closure year
Altona	109	2021
Kwiwana	146	2021
Bulwer Island	102	2015
Kurnel	135	2014
Clyde	85	2013
Total	**577**	

Source: Table by the U.S. Energy Information Administration, based on data from ExxonMobil, Ampol, and Viva Energy

Natural Gas

- Australia's proved natural gas reserves were 114 trillion cubic feet (Tcf) as of January 2022.[31]
- Coalbed methane (CBM) reserves were an estimated 29.8 Tcf, or 30% of total gas reserves, in 2019.[32] The majority of CBM reserves are located in Queensland, and New South Wales contains the rest.
- Unconventional gas reserves, not including CBM, were approximately 12.5 Tcf in 2019.[33]

Figure 6. Australia's dry natural gas production and consumption, 2010–2020



Source: Graph by the U.S. Energy Information Administration

Exploration and production

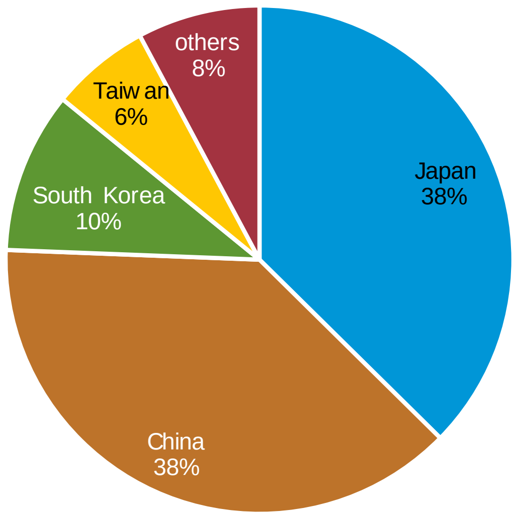
- Natural gas production in Australia was approximately 5 Tcf in 2020, nearly doubling since 2015 (Figure 6).[34]
- Between 2015 and 2020, nine new LNG liquefaction facilities with a total liquefaction capacity of 2.8 Tcf per year began operating.[35] The Northwest Shelf accounted for 65% of natural gas production, and the Bowen Basin and Surat Basin made up 26% in 2019.[36]
- The Bayu-Undan natural gas field, which supplies the Darwin LNG plant, will not produce natural gas after 2023,[37] according to the field's operator Santos.[38] The Barossa natural gas field, which is under development and is located offshore of the Northern Territory, will replace the Bayu-Undan field in supplying Darwin LNG.[39]
- The Leigh Creek Energy Project, located in the Telford Basin, was a coal gasification demonstration that showed the potential for producing synthesis gas, or *syngas*. Syngas is a mixture of carbon monoxide, carbon dioxide, and hydrogen that is produced from a carbon-based fuel, in this case coal. The gasification process converts coal in its solid form into a gaseous one. Leigh Creek Energy estimates the syngas reserves for this project are 1 Tcf.[40]
- According to Australia's 2021 National Gas Infrastructure Plan, domestic and export demand will likely exceed current natural gas supply by 2030, and the country will need at least one new basin to supply its government-projected demand.[41]

Consumption

- Australia consumed slightly less than 1.5 Tcf of natural gas in 2020 after remaining relatively flat between 2017 and 2020.[42]

- In 2019, electricity generation consumed approximately 36% of Australia's natural gas consumption. When on-site electricity generation was included, mining accounted for 32% of natural gas consumption, 28% for LNG plants and 24% for manufacturing.[43]

Figure 7. Australia's liquefied natural gas exports by destination, 2020



Source: Graph by the U.S. Energy Information Administration, based on data from BP Statistics

Liquefied natural gas

- In 2020, Australia passed Qatar to become the largest LNG exporter, at 3.7 Tcf,[44] or 0.1 Tcf more than in 2019.[45]
- Australia exports LNG almost exclusively to markets in Asia (Figure 7).[46] Australia is the largest supplier of LNG for the world's largest importers, supplying 43% of China's LNG imports and 39% of Japan's LNG imports in 2020. China was the second-largest LNG importer in the world, at 3.4 Tcf, and Japan ranked first, at 3.6 Tcf, that year.[47]
- At the beginning of 2021, Australia had 15 existing LNG liquefaction facilities with a total capacity of almost 4 Tcf per year.[48]
- Australia intends to add 6.6 Bcf per day of additional LNG capacity.[49] However, the prospective projects are facing supply challenges because Australia's natural gas production has declined. This limitation has forced producers to focus on meeting supply needs for existing facilities over building new ones.[50]
- The US $12 billion Scarborough LNG project is a joint venture between Woodside Petroleum and BHP Group. Woodside expects the project to produce 384 Bcf when its second train comes online in 2026. It will be supplied by the Scarborough gas field, which has reserves of 11.1 Tcf.[51]
- Because most of Australia's natural gas production occurs in the northwest, Australia's government is not expecting production in the south to keep up with demand in the area, according to the 2021 National Gas Infrastructure Plan. Import terminals are considered important in minimizing the risk of a supply shortage.[52] Port Kembla LNG in New South Wales

will be Australia's first LNG import terminal. Hoegh LNG expects the terminal to be operational by 2023.[53]

Table 3. Liquefied natural gas liquefaction plants in Australia, 2021

Refinery	Liquefaction capacity (billion cubic feet per year)	Year online
North West Shelf LNG T1-T2	240	1989
North West Shelf LNG T3	120	1992
North West Shelf LNG T3	221	2004
Darwin LNG T1	178	2006
North West Shelf LNG T5	221	2008
Pluto LNG T1	235	2012
GLNG T1	187	2015
Queensland Curtis LNG T1-T2	408	2015
GLNG T2	187	2016
Australian Pacific LNG T1-T2	432	2016
Gorgon LNG T1-T2	499	2016
Wheatstone LNG T1	214	2017
Wheatstone LNG T2	214	2018
Ichthys LNG T1-T2	427	2019
Prelude FLNG	173	2019
Total	**3,956**	

Source: Table by the U.S. Energy Information Administration, based on data from IGU 2021 World LNG Report

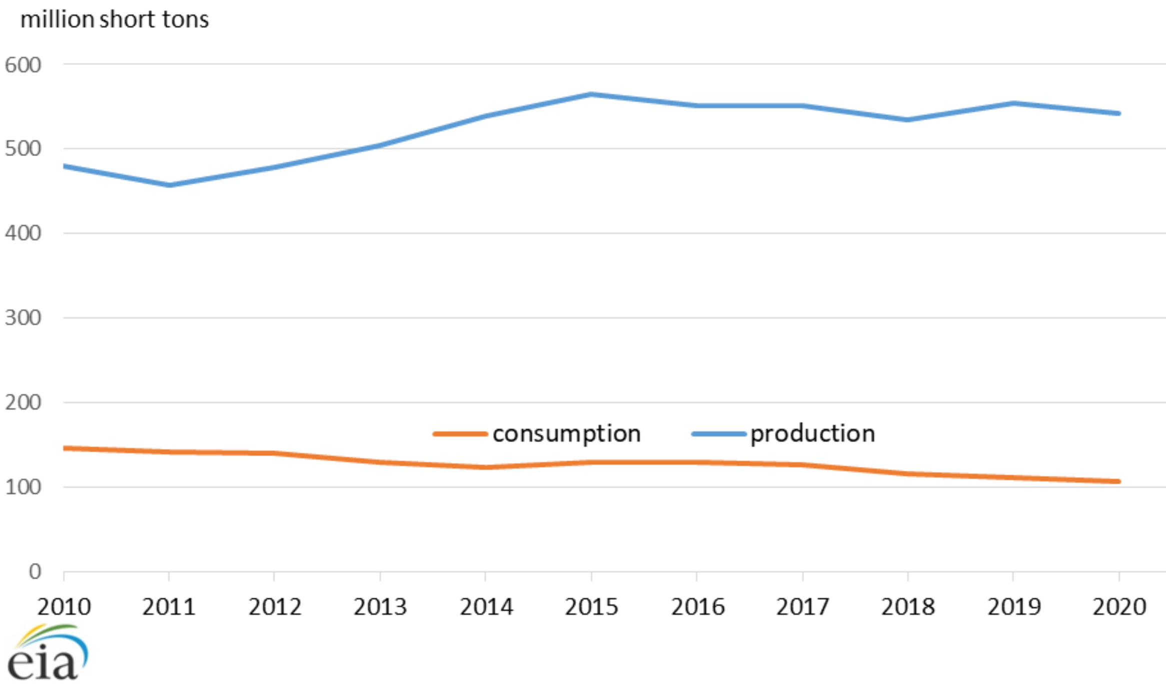
Pipelines

- Australia has over 24,233 miles (39,000 kilometers) of natural gas transmission pipelines.[54]
- The Northeast Gas Interconnector started operation in 2019. The 387-mile (622-kilometer) onshore pipeline is a joint venture of China's State Grid Corporation and Singapore Power, operated by Jemena.[55]

Coal

- Australia was the world's second-largest coal exporter by weight behind Indonesia, and first by energy content in 2020. Coal is the country's most abundant energy resource,[56] and coal ranks as the second-largest export commodity from Australia in terms of revenue.[57]
- Australia exported about US $69.6 billion worth of coal (both metallurgical and thermal coal used for electricity generation and other industries) in 2018, according to the latest data available.[58]
- In 2020, Australia held 166 billion short tons (Bst) of recoverable coal reserves, the third-largest in the world behind the United States and Russia.[59]
- The Australian government estimates recoverable proved and probable reserves to be 193 Bst at the end of 2019; slightly more than half comes from black coal and the remainder from brown coal.[60]

Figure 8. Australia's coal production and consumption, 2010–2020

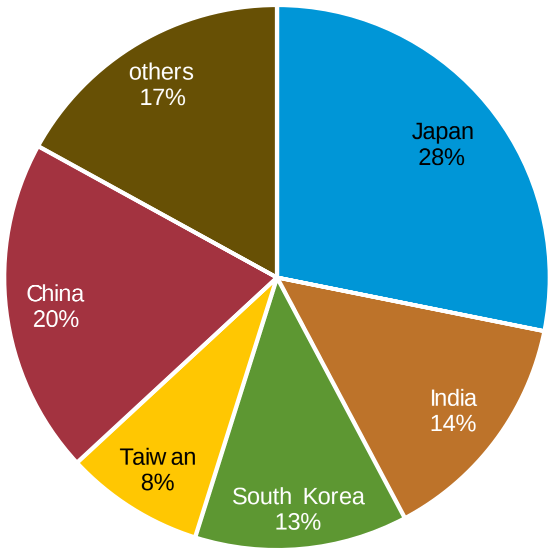


Source: Graph by the U.S. Energy Information Administration

Production and consumption

- Australia's coal production rose steadily from 2000 until it peaked in 2015 at 574 million short tons (MMst) (Figure 9). In 2020, the country produced an estimated 553 MMst of coal.[61]
- The Hydrogen Energy Supply Chain pilot project in Victoria is the world's first trial to show the effectiveness of producing hydrogen from brown coal. The resulting hydrogen is transported to Japan. The project started production in March 2021.[62]
- The Leigh Creek Energy Demonstration Project, completed in 2019, successfully used coal to produce syngas from the Telford Basin's 1.03 Tcf of natural gas reserves.[63] Leigh Creek Energy is working on the Leigh Creek Urea Project, which is the commercialization of the demonstration project. Once implemented, the project will produce syngas from deep and stranded coal reserves that will power a 5-megawatt (MW) power plant. Leigh Creek Energy expects the project to be constructed by March 2022. In subsequent phases, the plant will produce 1 million tons of nitrogen-based fertilizer. Other plans include the construction of a larger power plant and the production of urea fertilizer.[64]
- Most of Australia's coal is exported (446 Mst in 2020), and domestic demand accounted for less than one-quarter (107 Mst in 2020) of total production.[65]
- Coal plays a major role in meeting domestic energy needs, accounting for approximately 54% of Australia's electricity generation in 2020, according to government statistics.[66] In the past several years, Australia has focused on substituting some coal-fired generation with natural gas-fired power and renewable power. Coal consumption for electricity generation has decreased by 18% since 2016 as a result.[67]

Figure 9. Australia's coal exports by destination, 2020

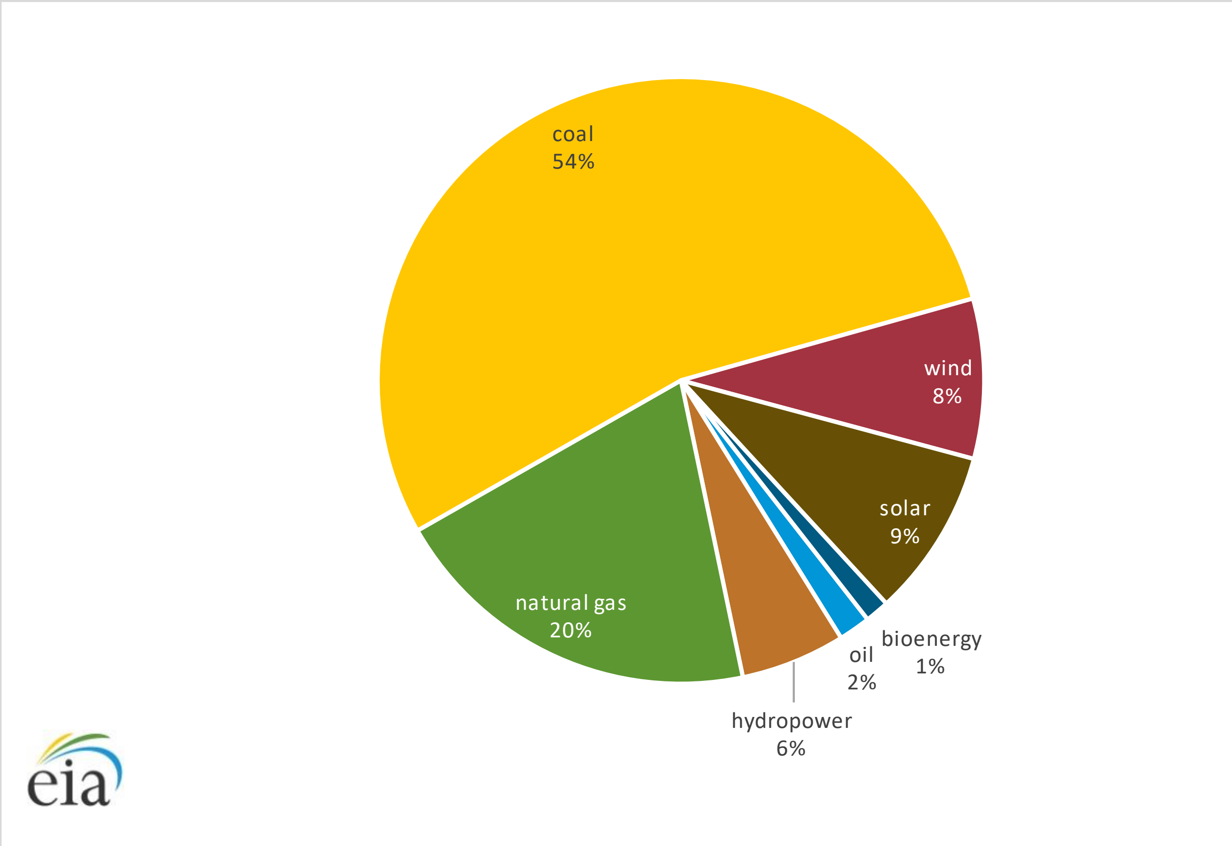


Source: Graph by the U.S. Energy Information Administration, based on data from Global Trade Tracker

Exports

- Australia remained the second-highest coal exporter on a weight basis in 2020 behind Indonesia. Total coal exports (almost 430 MMst in 2020) were only slightly lower than the 2019 total (433 MMst).[68]
- Most of Australia's coal exports go to countries in Asia. Japan (28%), China (20%), India (14%), and South Korea (13%) import most of Australia's coal (Figure 9).[69]
- China, Australia's second-largest importer of coal for the past several years, accounted for 20% of the country's coal exports in 2020. However, coal exports to China dropped to virtually zero in 2021. Tension between Australia and China had been rising since 2018 when Australia banned China's Huawei from their 5G cellular networks. In late 2020, after Australia called for an inquiry into the origins of COVID-19, China initiated trade restrictions on some Australian exports, including beef, barley, wine, and seafood.[70] China also placed an unofficial ban on coal from Australia. This unofficial ban left shipments of an estimated 1.1 MMst of coal from Australia stranded in China. As of the end of 2021, only small amounts of the stranded coal have been released into China.[71]

Figure 10. Australia's net electricity generation by fuel, 2020



Source: Graph by the U.S. Energy Information Administration with data from Australia's Department of Industry, Innovation and Science

Electricity

- Electricity generation in 2020 decreased approximately 3% from 250 terawatthours (TWh) in 2019, to 243 TWh.[72]
- Fossil fuels supplied about 76% of Australia's electric generation in 2020, decreasing approximately 3% from 2019. Coal made up the majority of electricity generation (Figure 10). Black coal (41%) and brown coal (13%) accounted for 54% of total generation. Natural gas-fired generation supplied 20% of total electricity generation.[73]
- Renewable sources, such as wind, bioenergy, and solar, have rapidly grown from less than 1% of total electricity generation in 2000 to more than 19% in 2020. Solar contributed the largest share of generation from renewables (9%), surpassing hydroelectricity as Australia's largest source of renewable energy.[74]
- Wind energy, the second-largest renewable source for electricity, has grown substantially in the past decade and accounted for 8.5% of total electricity generation in 2020.[75]
- Hydroelectricity, accounting for 6% of total electricity generation in 2020, is available in the states of Tasmania, Victoria, and New South Wales.[76]
- Australia hosts several battery storage projects in various stages of completion. These projects aim to make the national grid more efficient at both the transmission and distribution levels.[77] Currently, the largest operating battery is the Victorian Big Battery in Geelong.[78] The 300-MW

grid-scale lithium-ion battery storage system came online at the end of 2021 and stores enough energy to power over 1 million homes for up to 30 minutes.[79]

- In 2021, Australia released its National Hydrogen Strategy, which outlines its potential in the market. Currently, Australia has plans for green hydrogen projects with 69 gigawatts of proposed total capacity.[80]

Notes

- Data presented in the text are the most recent available as of March 4, 2022.
- Data are EIA estimates unless otherwise noted.

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President and CEO

May 30, 2023

California Energy Commission
Docket Unit, MS-4
Docket No. 23-SB-02
715 P Street
Sacramento, California 95814

Submitted via email to docket@energy.ca.gov

RE: WSPA Comments Regarding SB 2 Implementation Workshop [Docket #23-SB-02]

Thank you for providing an opportunity for the regulated community to comment on the California Energy Commission's (CEC) May 16, 2023 hybrid workshop that was dedicated to informing the public of the proposed plan to implement Senate Bill (SB) X1-2 (2023). The Western States Petroleum Association (WSPA) is a non-profit trade association representing companies that import and export, explore, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California.

SB X1-2 directs state agencies to evaluate how to ensure that petroleum and alternative transportation fuels are adequate, affordable, reliable, and equitable. Implementation will necessarily require that transportation energy companies make **significant** investments to maintain and upgrade the fuels infrastructure – upstream, midstream, and downstream. These investments must be economically viable if we are to meet the strong fuels demand today and for decades to come. We fully recognize that transforming the world's third largest fuels market will not be easy. Nor will it be easy or inexpensive to significantly upgrade and dramatically expand California's electric grid to accommodate the anticipated electrification of the transportation and building sectors, especially in underserved areas. It is therefore equally important that the state closely evaluate what investments must be made in both systems to meet the diverse energy demands of all Californians, as well as steps that can be taken to facilitate a more expedient permit review process to enable these necessary investments in the ongoing energy transition.

The implementation of the voluminous new requirements in SB X1-2 and SB 1322 (2022), while continuing to protect confidential business information, will require significant efforts from both stakeholders and CEC alike. Coordination will be required by all involved to explain, clarify, interpret and carry out these many new obligations, which is why we believe CEC will need to exercise its existing statutory flexibility by prioritizing implementation efforts and phasing in reporting and compliance obligations. Accordingly, in addition to a formal rulemaking process, WSPA requests assurances that CEC will host additional workshops and provide ample time to review and answer questions about any new or modified reporting forms well in advance of any reporting deadline, which has been identified by CEC staff as June 26, 2023. Regulated entities must have sufficient time to ensure internal protocols are in place at the CEC and within their organization to collect and report the requisite information in a responsive, accurate, and timely manner. The public also deserves to know the full scope of the burdens that will be placed on the facilities, stakeholders, and CEC in the implementation of these new laws, which will add costs to both CEC and the regulated community.

INTRODUCTION

WSPA continues to strongly believe that a formal rulemaking process is necessary to ensure clarity, consistency, and accuracy for both CEC staff and all regulated entities in interpreting, implementing, and properly complying with SB X1-2 (including SB 1322). Formal rulemaking is also necessary to help ensure that CEC can continue to protect highly confidential and proprietary data in accordance with, among other things, federal antitrust and state reporting laws, which remains a major concern because this valuable competitive information could be a target for hackers or subject to leaks.

We understand that the CEC intends to work in an administrative capacity to implement the new laws as the new Division of Petroleum Market Oversight and the new Independent Consumer Fuels Advisory Committee are established and staffed. We strongly recommend and urge that the CEC prioritize and narrow the scope of SB X1-2's initial reporting requirements during this start-up period. Doing so would help to ensure regulatory certainty and compliance for known obligated entities now, while providing time to phase in compliance for unknown or newly obligated entities in the future as the state hires and trains additional staff and new entities are apprised of new reporting requirements and related rules. We strongly encourage CEC to conduct a public stakeholder survey to identify all regulated entities involved as there could be some that are unaware of their obligation to comply with the law in addition to the parts of the statutes that regulated firms do not yet fully understand; this will help ensure CEC receives the additional input necessary to effectively implement the statutes as the Legislature intended. An adequate defendable analysis that responds to the objectives of this legislation must include wholistic market input versus a "cherry picking" of only available information from a portion of the market.

We welcome the opportunity to work with CEC through workshops and staff-level industry working groups (including, especially, with respect to information technology issues) to implement these new laws in a manner that allows for understanding and compliance while also protecting all market-sensitive, confidential, and proprietary data and ensuring that all applicable cybersecurity and data privacy regulations are followed.

EXPANSIVE SB X1-2 DATA COLLECTION EFFORT

WSPA does not seek to delay new data reporting requirements; as you know, our members already gather and report a wide array of data to CEC on a regular basis. Rather, we seek to work with CEC to ensure effective implementation and standardized reporting practices when the new requirements go into effect. For example, CEC previously used interim data reporting forms to initiate expanded data collection while a formal rulemaking process was underway following the Legislature's 2003 expansion of the Petroleum Industry Information Reporting Act of 1980. This would be a helpful model for SB X1-2 implementation given both the incredibly expansive nature of the new data collection, the ambiguities and open questions within the legislation, and the numerous additional regulated entities involved who have not yet had to comply with these first-of-their-kind reporting requirements.

The amount of data reported to CEC will dramatically increase under SB X1-2. For example, if CEC chooses to require reporting of contracts and agreements under Section 25354, subdivision (i)(2)(F), that could require refiners alone to report some 30,000 total contracts and agreements with up to approximately three million pages of documents, in addition to the 500,000 daily transactions (or 182.5 million transactions per year) required by subdivision (l). Thus, the CEC will need to work with all reporting facilities under the new laws to develop a system to manage terabytes of new data. Both the state and obligated parties will need to develop systems and processes for how this information is collected and shared with the CEC, along with defining limitations and protections around how it is shared with third parties and other agencies.

We trust CEC would agree that indiscriminate collection of copious but irrelevant information helps no one. Imposing a vast new laundry list of mandatory reporting topics starting June 26, without first assessing the necessity, costs and benefits of gathering certain types of information, would cause undue burdens on reporting entities and on CEC's own staff and technology resources. Indeed, the stated goals of the legislation would be frustrated if CEC ends up having to collect, store, and is required to protect vast amounts of data with little or nothing to do with gasoline prices (e.g., propane, petrochemicals, asphalt, etc.). Accordingly, we recommend that CEC exercise its discretionary authority to collect data based upon identified priorities and staffing and technological constraints, while assessing what types of information truly address the central issue of extreme gasoline price spikes. Providing further clarity around these new reporting requirements, would prevent varied and inconsistent responses from industry, and prevent incorrect conclusions and monumental burdens on the CEC.

We share CEC's goal of ensuring the production and sharing of responsive, high quality and consistent data and appreciate that the CEC shares the desire for clarity, consistency, and accuracy in data reporting. WSPA continues to believe that a joint staff-level working group would be helpful in determining priorities, based upon what can be more readily implemented first. We also suggest CEC staff establish a more formalized process to ensure regular check-ins with the regulated community – including, specifically, information technology experts – to provide a forum for questions to be raised and clarification sought. Establishing clear and reasonably implementable rules, guidance, forms, and instructions for the new reporting requirements will be beneficial to both CEC and the regulated entities by offering much needed clarity given the gaps identified to date.[1] "Attachment A" of WSPA's May 11, 2023 rulemaking petition letter provided an initial, but incomplete, list of issues and questions that we continue to supplement based upon ongoing internal reviews.

WSPA has identified many more open issues in "Attachment A" of this comment letter. Among these issues are impediments to compliance with various provisions of SB X1-2's reporting requirements. For example, regarding the 96-hour pre-import reporting requirement (Cal. Pub. Res. Code (PRC) Section 25354(j)(2)), it will be challenging for regulated entities to provide the information requested because purchases arrive "as delivered" and the source is not necessarily known. Additionally, providing the status of any transportation fuel "as sold before discharge," in addition to the buyer's identify for any presold product and sale price of any presold product (PRC Section 25354(j)(5)), will be problematic because companies cannot track fuel product by molecule and have no way to track the fuel volumes made in specific sales or market contracts to specific tanks in specific vessels. In addition, in daily spot market transactions, there is often a lag between the contract execution and settlement, meaning that data reported at time of contract execution may not accurately reflect updated information about

[1] See "Attachment A" in WSPA's May 11, 2023 petition for formal rulemaking filed with CEC

the fuel ultimately purchased. Occasional deal entry errors may occur as well. While PRC Section 25354(l)(15) requires the reporting of the invoiced volume of each transaction, exact volumes and pricing terms may not be known until invoiced. Daily reporting is therefore extremely cumbersome, with multiple lags, and would therefore benefit from longer lead periods to reconcile.

In addition, under SB X1-2's definitional terms it is unclear if operational costs (PRC Section 25355(b)(8)) are intended to include only the costs associated with refining or also include the distribution, marketing costs associated with bringing product to spot pipeline sales, unbranded, branded wholesale rack and DTW sales. Like concerns with "gross gasoline refining margin," the term "net gasoline refining margin" may also artificially inflate the appearance of margin as it is unclear whether all costs associated with reported sales are included in the calculations. For example, it is unclear whether the "net gasoline refining margin" calculation includes CARB mogas purchases, marketing expenditures, and full allocation of crude expenses (to account for the impacts of other products), and/or if it includes or excludes market and distribution costs outside the refinery.

Fortunately, as with other PRC statutes, the recent statutory changes provide the CEC with helpful flexibility to exercise discretion where the term "may" is used and also explicitly provide that CEC can determine the "form and extent" of new reporting requirements. Although much of the data and materials outlined in the new laws may be beneficial to CEC's analysis and reporting to "ensure adequate gasoline supplies and prevent future extreme price spikes for gasoline prices in California,"[2] other data and materials that could be required likely are not.

IMPORTANCE OF ENSURING SB X1-2 DATA SECURITY

The oil and gas industry is one of 16 federally identified critical infrastructure sectors that provide essential services to the public. Federal agencies, including the Transportation Security Administration (TSA), the Federal Energy Regulatory Commission, and the Cybersecurity and Infrastructure Security Agency (CISA), are tasked with leading efforts to constantly improve sector security, particularly as cyber threats become more prevalent. The TSA has released the Security Directive Pipeline 2021-02, which requires companies that operate pipelines to create cybersecurity implementation plans, incident response plans, and assessment programs. Previous Directives also require compliance with certain cybersecurity standards developed by the National Institute of Standards and Technology, which are designed to help protect these sectors designated as critical. For reference, CISA has also developed best practices to assist governmental entities to protect against cybersecurity risks including by strengthening cyber posture through secure planning and design, proactive supply chain risk management, and operational resilience.[3] Additionally, to help carry out the National Cybersecurity Strategy released in March 2023, CISA is working to develop best practices specific to each critical infrastructure sector. The energy sector has stepped up to accomplish this first.

Unquestionably, the illegal access, ransom and release of confidential business oil and gas industry business data can move entire markets, negatively impact individual companies seeking to comply with California's new law, and dramatically affect the everyday lives of consumers. This cannot be overstated. Federal regulatory agencies are following Federal Information Security Management Act high requirements and are required to be assessed and

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[2] CEC Notice of Senate Bill 2 Implementation Workshop – May 16, 2023 agenda https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-SB-02.
[3] https://www.cisa.gov/resources-tools/resources/cybersecurity-best-practices-smart-cities

comply with these requirements. There are equivalent protections and assessments for the CEC.

Data gathering must both preserve confidential trade secret information and comply with a panoply of applicable federal antitrust and state reporting laws and international data privacy laws, which could impose steep fines if violated. Release of market-sensitive data not only can harm the regulated businesses but also can give malicious actors an opportunity to engage in market manipulation. Proper protection of information should be achieved through the aggregation or withholding of confidential data before any public release, as well as through the robustness and integrity of CEC's own information technology (IT) system to guarantee the protection of this market sensitive information.

These new reporting obligations are far from the only legal obligations that refiners must comply with. There is a growing suite of cybersecurity directives and regulations at all levels of federal and state government, as well as reporting laws in other states and strict limitations on the dissemination and accessibility of sensitive data under federal antitrust law. To ensure that California's new reporting regime does not force companies to run afoul of their overlapping obligations to other states and the federal government, CEC needs to ensure that its own IT systems are properly configured and managed in order to protect confidential and proprietary information. Tools like encryption, limitations on access, and the segmentation of data (*i.e.*, storing related information in different places so as to minimize the impact of any breaches) are essential in safeguarding sensitive information that CEC intends to collect.

As WSPA works together with CEC to inform the standards CEC will use and guarantee the robustness of CEC's IT system, we plan to share with CEC several specific issues and concerns where failure to adequately protect this information from disclosure will harm regulated industry entities, and may result in the extreme price spikes CEC seeks to avoid. Attachment B of this comment letter, the ITSP Questionnaire, includes an industry standard list of 23 questions we request the CEC provide detailed answers to via the confidential transmittal to WSPA that we can share with our members. This will best help WSPA member companies assess the IT specifications and safeguards CEC will use to protect the information to be collected under SB X1-2 commencing June 26. WSPA further requests detailed follow-on discussions with CEC IT staff, management, and leadership to discuss these details and afford WSPA member companies the comfort necessary in the robustness of CEC's information sharing infrastructure, that CEC will protect the information when shared with any other state agency or division, and that the CEC's possession of a vast quantity of highly confidential and sensitive market information pertaining the world's third largest fuels market will easily pass any independent audit. We would also appreciate that CEC name a dedicated senior staff contact who will be responsible and accountable for answering industry questions and addressing concerns.

SHOULD PROFITS BE PENALIZED?

SB X1-2 included in its findings and declarations section an incorrect and unfortunate claim – *i.e.*, that gasoline price spikes in the fall of 2022 were "caused by refiners." While this claim has been raised and analyzed by California many times before, the real-world market evidence has always refuted it and properly identified the underlying market factors of supply and demand as driving costs. Indeed, costs often have more to do with basic retail factors than refining. Even third-party experts have concluded that a cap on refinery margins has the potential to *harm consumers and drive prices up* by aggravating California's increasingly structural supply constraint issues – leading to the extreme gasoline price spikes the CEC is tasked with preventing and mitigating.

Fortunately, the language of SB X1-2 was corrected to first require CEC to gather real-world evidence on whether a cap on refinery margins could have unintended consequences that would harm California consumers.

> The law provides that CEC "*shall not* set a maximum gross gasoline refining margin or accompanying penalty . . . *unless* it finds that the likely benefits to consumers outweigh the potential costs," considering factors such as whether action would lead to a greater supply and demand imbalance in California's fuels market or lead to higher pump prices." See PRC Section 25355.5(I).

It is therefore incumbent upon CEC that, before deciding whether to cap or penalize refining profits, it must first evaluate the potential impacts and unintended consequences of adopting such a cap and assess whether the actual market evidence indicates that such a cap will do anything to help California consumers by addressing the underlying fundamental market reasons for rising prices – *i.e.*, ongoing market volatility due to a lack of supply in the market accompanied by very strong demand. No analysis will be adequate and accurate unless the CEC looks at *all* variables impacting the market, including land use decisions, the lack of permitting, regulatory actions, etc. that impact fuel supplies. The CEC will not be in a position to make a well-informed decision, supported by a meaningful and fair analysis, without confronting and analyzing these variables.

To this point, in recent history, numerous Attorneys General have independently investigated California's refiners and confirmed that the refining industry has ***not*** engaged in price gouging. The CEC's own Integrated Energy Policy Reports (IEPR) even predicted elevated gasoline costs to consumers dating back to 2003/2004 based on the same considerations – *i.e.*, that fuel prices are driven by larger market forces of supply and demand. Furthermore, both the Federal Trade Commission and CEC investigated or conducted multiple studies of the "residual price increase" in California's fuels market following the 2015 Torrance refinery incident and concluded that refinery margins were found not to be the cause.

In addition to the SB X1-2-directed considerations CEC must consider when investigating if a maximum gross refining margin is justified, WSPA also encourages the Commission to consider fundamental fuels market issues that directly impact gasoline prices. These issues and other questions include how a gross refining margin would impact petroleum cost or statewide supply; what precedent/legal authority the CEC would set for California business as a government entity attempting to determine what income a California business should be "allowed" to earn; what an appropriate profit (or loss) amount/percentage would be for a private company within only one specified industry while other industries have no such limit; what specific factors CEC would consider in even attempting to set such a level; how to determine what percentage of a refiner's income it would be required to pay to the state; and what financial support CEC would offer to facilities operating at a loss (as California has already done for the electric utility industry for power plants).

TRANSPORTATION FUELS TRANSITION STUDY

It is undisputable that the electrification transition is unlikely to be smooth or equitable for many Californians, particularly low- and moderate-income residents and small businesses. We therefore encourage CEC and the California Air Resources Board (CARB) to include in the SB X1-2-mandated Transportation Fuels Transition Plan an evaluation of fuel demand and price scenarios that incorporate low, medium, and high fuel demand scenarios – especially given the uncertainties raised by CARB as part of the 2022 Scoping Plan Update. This includes significant uncertainties for permitting wait times and local ordinances that may limit or slow the rapid build-out of utility-scale renewables, the ability to deploy renewable energy at the pace modeled, addressing known constraints with widespread transportation electrification (including grid readiness, affordability, and commercial availability), and the aggressive reduction of Vehicle Miles Traveled called for in the 2022 Scoping Plan Update.

We also note that, for the purposes of CEC's IEPR, by charter, the analyses supporting it must explicitly address interfuel and intermarket effects to provide a more informed evaluation of potential tradeoffs when developing energy policy across different markets and systems. The IEPR must include an assessment and forecast of system reliability and the need for resource additions, efficiency, and conservation. This assessment must consider all aspects of energy industries and markets that are essential for the state economy, general welfare, public health and safety, energy diversity, and protection of the environment.

The required fuel scenarios analysis should forecast how current and anticipated transportation fuels infrastructure limitations have and will impact energy supply and market dynamics. The CEC and CARB should determine what level of incremental investments will be required by the State of California and/or expected by industry to maintain and build-out needed infrastructure to ensure the provision of adequate, affordable, and reliable energy options for all Californians. Minimizing such market volatility would necessarily include identifying policy changes to support (rather than hinder) critical investments in the maintenance and build-out of infrastructure to support both existing fuels demand and new energy needs. The CEC should also quantify the gap between the forecasted state of current transportation energy infrastructure and the build-out of new infrastructure across the demand forecast scenarios and its impact in terms of potential supply shortfalls.

WSPA agrees with CARB's recognition in the 2022 Scoping Plan Update that a complete phaseout of oil and gas extraction and refining by 2045 is not feasible and would lead to significant "leakage" of California businesses and accompanying GHG emissions to other states, defeating the stated purposes of statewide climate regulation. WSPA expressed repeated concerns with CARB's reliance on a Zero Emission Vehicle (ZEV)-only approach in achieving the state's greenhouse gas (GHG) and air quality goals within the transportation sector. As we commented during the Scoping Plan's development and through the Advanced Clean Trucks, Advanced Clean Cars II, and Advanced Clean Fleets rulemakings, CARB's analyses failed to evaluate cost-effective air quality and GHG reduction benefits that other technology options, such as near-zero emissions vehicles and low-carbon and renewable fuels, could deliver. WSPA requests that the Fuels Transition Study called for in SB X1-2 analyze and consider the benefits of utilizing alternative pathways, including using renewable and other low carbon fuels, that can dramatically reduce transportation sector carbon emissions without simply forcing emitting activities and associated businesses out of state, and without ZEV mandates for achieving carbon neutrality and improving air quality in highly impacted communities.

Assembly Bill 32 (2006) requires CARB to minimize "leakage" of GHG emissions from California's economy. As WSPA raised in comment letters to CARB, the significant potential for leakage of emissions due to technology forcing mandates in the 2022 Scoping Plan Update ignores the life cycle emissions of “zero emission” vehicles. Importantly, life cycle GHG emissions associated with ZEVs are not zero, but include all the GHG emissions created from mining materials for batteries to disposing of ZEVs at the end of their useful lives. The 2022 Scoping Plan Update did not assess the leakage of these life cycle emissions that would be caused by increased mining activities, battery production, recycling, and disposal under the proposed light-duty vehicle and medium-duty vehicle/heavy-duty vehicle ZEV mandates. It also did not consider the life cycle emissions and other environmental impacts that would be caused by a dramatic development of electric infrastructure, including solar panels, wind turbines, and grid-scale battery production impacts. All of these have considerable embedded GHG emissions and would largely be produced outside California. Further, actions to phase down California’s oil and gas extraction and refining would cause increased production and refining of liquid fuels outside of California from operations with higher GHG intensities. All of these unconsidered impacts would represent emissions leakage.

Technology-neutral, performance-based standards could be an affordable alternative to ZEV mandates and would more completely characterize the potential life cycle GHG emissions impacts of a ZEV option versus other options. Performance-based standards also have the significant advantage of not requiring the replacement of California’s entire transportation infrastructure system and requiring the wholesale transformation of the electric energy production and distribution infrastructure on an unprecedented time scale without full evaluation of the totality of other environmental impacts. This would maintain equitable emission reductions across the transportation sector while significantly abating the technological and economic concerns surrounding the proposed ZEV mandates. We continue to ask CARB to fairly evaluate a plan that allows for this alternative pathway to achieve carbon neutrality with fewer feasibility challenges and lower costs.

SB X1-2 states in part that the Transition Plan “shall be prepared in consultation with the state’s fuel producers and refiners” and “shall include, at a minimum, a discussion of how to ensure that the supply of petroleum and alternative transportation fuels is affordable, reliable, equitable, and adequate.” WSPA looks forward to working closely with the CEC, CARB, and the new Division of Petroleum Market Oversight to inform the Transition Plan’s development – including the analysis of multiple demand case and price scenarios. Equity must be a central part of this study to help inform policies under the base assumption that internal combustion engine vehicles (including hybrid vehicles) will be used and needed by Californians for decades to come, and that fuel affordability be a guiding tenet.

TRANSPORTATION FUELS ASSESSMENT REPORT

WSPA looks forward to working with the CEC to inform its development of the first triennial Fuels Assessment Report. The statute is clear in requiring CEC to identify methods to ensure a reliable supply of affordable and safe transportation fuels while evaluating prices, supply and employment conditions and potential refinery closure impacts, and the cost and cost-effectiveness of any proposal.

In addition to the points raised above for the Transportation Fuels Transition Study, the CEC must analyze the existing state of California’s legacy oil and gas infrastructure that is substantially supporting our energy economy. This must be inclusive of the entire supply chain – upstream, midstream, downstream, and retail/marketing – and should include an analysis of the root causes of the infrastructure challenges and related supply issues. WSPA recommends that CEC utilize CalGEM production data to assess the differential in what CARB has assumed (approximately 3% annual production decline in the 2022 Scoping Plan) versus what CalGEM data has shown (approximately 10-15% decline depending on the data set used).[4] We also recommend CEC evaluate regulatory barriers preventing needed maintenance activities, policies and processes that challenge infrastructure from being repurposed, and policies and processes preventing significant new infrastructure investments by creating long-term uncertainties. It continues to be a pressing issue for California gasoline supply that most refineries outside of California cannot produce fuels that meet California's strict specifications for gasoline.

WSPA encourages CEC to closely evaluate how existing state policies have impacted the in-state production and refining of petroleum fuels as part of this assessment. Given that CARB's 2022 Scoping Plan Update seeks to marry demand with supply, we believe such an evaluation will show that the state has taken numerous steps to artificially reduce production (and therefore constrained supply) of petroleum fuels needed by refineries to meet California's ongoing and high demand. California produces and refines the cleanest hydrocarbons available – under the strictest environmental policies in the world – and any artificial constraint that reduces in-state supply and production must be compensated for by refineries elsewhere around the world that are outside the jurisdiction of California's strict environmental policies.

SUMMARY

In addition to commencing the recommended formal rulemaking process, WSPA also encourages CEC to ensure that compliance be phased in as additional information is gathered about regulated entities, priorities are determined, staff are hired and IT resources deployed. It is only as additional information is identified and understood that CEC will get a clear picture of how to efficiently and effectively structure reporting and data gathering requirements. With the multitude of outstanding issues and questions and such a short window of time before reporting commences, a phased-in approach is truly required.

Thank you for considering our comments. We look forward to working with the CEC to provide ongoing input to ensure regulated entities have the instructions and materials needed to properly comply, to ensure that the data submitted is responsive and consistent across the industry, and that the information is well-protected. Please do not hesitate to contact me at (916) 498-7752 or cathy@wspa.org with any questions, or Tanya DeRivi on my staff, who can be reached at (916) 325-3088 or at tderivi@wspa.org.

Sincerely,

cc: The Honorable David Hochschild, California Energy Commission, Chair
The Honorable Siva Gunda, California Energy Commission, Vice Chair
Shant Apekian, WSPA

[4] California Department of Conservation, WellSTAR monthly production data reports, 2018-2023, https://www.conservation.ca.gov/calgem/Online_Data/Pages/WellSTAR-Data-Dashboard.aspx

ATTACHMENT A – REVISED 5/30/2023

SB X1-2 Items Requiring Clarification Through Rulemaking
The bulleted categories and sections below describe areas of the statutes at issue that still require additional clarity and would benefit from the rulemaking process. WSPA and its members are still evaluating the statute for additional items that require clarification so that the legislature's intent for transparency and clarity can be achieved. We expect to complete that process and convey such information to CEC prior to or during the rulemaking process.

- **Definitional Terms**
  - In **Section 25354(a)**, the use of the word "existing" is confusing; it is unclear if it is intended to mean changes to reporting that is occurring today.
  - In **Section 25354(a)(1)** the term "price" may not be available or able to be calculated. The term lacks specificity in application to receipts, inventories, and exports.
  - In **Section 25354(a)(1)** the "entity receiving those exports" may not be knowable if they are the final recipient. This is possibly infeasible for foreign exports, especially marine cargos with multiple deliveries and marine cargos that are sold to another entity prior to delivery to its final destination.
  - **Section 25354(a)(1)** requires refiners to report "all current inventories of refined and unrefined petroleum products." The term "unrefined petroleum products" is undefined and could have multiple meanings.
  - In **Section 25354(b)**, the use of the word "existing" is confusing; it is unclear if it is intended to mean changes to reporting that is occurring today.
  - **Section 25354(b)(6)** introduces "Pipeline Operator" as a new party without defining this term.
  - **Section 25354(h)(2)** requires refiners to report monthly on "weighted average prices and sales volumes for residential sales, commercial and institutional sales, industrial sales, sales through company operated retail outlets, sales to other end users, and wholesales of No. 2 diesel fuel, No. 2 fuel oil, and any renewable fuel." The new term added "renewable fuel," which is not listed on the EIA form and provides no specificity as to the different types of renewable fuels that would be reported. Clarity is needed to determine the feasibility of reporting these types of fuels as they are typically blended into gasoline, and ultra-low sulfur diesel fuels.
  - **Section 25354(i)(2)(F)** may require reporting of "copies of all contracts or agreements entered into, or amendments to contracts or agreements, with other oil refiners, oil producers, petroleum product transporters, petroleum product marketers, petroleum product pipeline operators, terminal operators, or any other entity that trades in petroleum products whether or not those entities take possession of petroleum products, as designated by the commission, during the monthly reporting period, along with records of every transaction made under those contracts or agreements and the prices charged for those transactions." This section could be widely interpreted and may result in multiple submissions of the same documents, in addition to the questionable necessity of these contracts having to be submitted each week.

- **Section 25354(j)** uses the term “importers.” It is unclear if this means the owner of the cargo, the importer of record prior to transfer of title at the point of discharge at the marine terminal, the owner of the vessel, or the company that chartered the vessel.
- **Section 25354(j)** states reporting must happen “at least 96 hours before the arrival.” This 96-hour rule may impact supply of “refined products and renewable fuels” if ships must sit out at sea waiting for the 96 hours to pass before “delivery to California.” If 96 hours is the requirement, sometimes what is planned can be provided – which may be different from what actually happens.
- **Section 25354(j)** uses the term “imports,” but it is unclear if this means imports from foreign countries or imports from domestic resources as well (e.g., the United States Gulf Coast and Pacific Northwest).
- **Section 25354(j)(2)** may be challenging to provide the information sought; sometimes purchases are “as delivered” and the source is not necessarily known.
- **Section 25354(j)(4)** uses the term “landed cost,” which may not be knowable for many imported cargoes since an importer transfers ownership at the berth and can be on a floating basis against different benchmarks. This information may be challenging to provide as it does not link costs to every purchase.
- **Section 25354(j)(5)** may be challenging to provide the information sought; as transportation fuel is not tracked by molecules, so there is no way to apply the volumes to specific sales or marketing contracts.
- **Section 25354(l)** may need to be limited to the data “if applicable,” as all of the information required for each transaction may not apply to each such transaction. Daily reporting of this information is expected to be extremely cumbersome, even if it can be achieved at all. Given the complexity and size of data requested, there should be more time allowed to collect the requested data. There is no indication that this information is needed or will be actioned on an urgent basis, so there would be little benefit to regulators for a slightly longer period to collect and validate the vast amount of information requested. WSPA suggests that this requirement be changed to a daily report that reports out three business days after each transaction given the need for reconciliation of information, where a longer lag period would be beneficial. Further, it is unclear how reporting would be conducted on a Saturday, Sunday, holidays or during emergency events when resources are limited.
- **Section 25354(l)(1)** refers to the term “spot market.” This does not specify which spot markets are to be included under this provision. It is unclear if this could include the San Francisco Bay Area or Los Angeles, or Pacific Northwest, Gulf Coast, Atlantic Coast or Midwest. There should be clarity on which spot market transactions would need to be reported under this subsection.
- **Section 25354(l)(8), (9), (11)** <u>requires the name, or nonanonymized identification, of the broker, as well as the executing and counterparty trader for transactions. Collection of international personal data under the General Data Protections Regulation (GDPR) has specific guidelines for processing data that CEC must consider and develop transparent privacy safeguards per GDPR requirements.</u>
- **Section 25354(l)(14)** requires reporting of the volume of each transaction in thousands of barrels, or other unit of measurement, if unable to be indicated in thousands of barrels; however, this information may only be known as an estimate.

- **Section 25354(l)(15)** requires reporting of the invoiced volume of each transaction in thousands of barrels, or other unit of measurement, if unable to be indicated in thousands of barrels; however, there may be a lag in providing this information if not known until invoiced given a wide range of payment terms.
- **Section 25354(l)(19)** requires the actual title transfer date; however, this may not be known until after the fact.
- **Section 25354(l)(16)** requires the "time and date" of a transaction. Spot mark transaction published each business day by OPIS for the West Coast identify pipeline cycles, rather than specific dates and times.
- **Section 25354(l)(18)** requires reporting of methods of transportation such as pipeline, marine vessel, or truck. Spot market transactions published each business day by OPIS for the West Coast are only for pipeline delivery.
- **Section 25354(l)(19)** requires reporting of "the actual title transfer date." The actual title transfer usually takes place upon transfer from one party to another. Since spot pipeline transactions reported by OPIS are for future delivery, it could be infeasible to know what date transfer will occur when reporting spot transaction each day.
- **Section 25354(m)** and **(n)** requires further clarification regarding whether this section applies only to maintenance at producing units at a refinery and excludes storage or pipelines inside the refinery gate.
- **Section 25354(m)(1)(C)** refers to "return-to-service date." This should be properly defined to clarify how to treat circumstances of gradual ramp-ups for processing units to return to full service.
- **Section 25354(m)(1)(E)** refers to "operational capacity." This should be further defined to clarify either barrels per stream day or barrels per calendar day.
- **Section 2535 (m)(1)(G)** refers to "finished gasoline." Decreased output of gasoline component from process units associated with either planned or unplanned work are not "finished gasoline" that contains ethanol at a concentration of 10% by volume. This needs to be clarified to properly compare reported declines in process unit output to the contractual supply obligations.
- **Section 25354(m)(1)(K)** refers to "noncontracted sales of gasoline." This requires clarification.
- **Section 25354(m)(4)(A)(iv)** requires "a description of the season for the unplanned maintenance or outage." This may not be known with 48 hours of the unplanned outage due to restricted access to the damaged unit and/or equipment.
- **Section 25354(m)(4)(A)(v)** requires "a projected duration of production reduction." This may not be known with 48 hours of the unplanned outage due to restricted access to the damaged unit and/or equipment.
- **Section 25354(o)** requires refiners to "report annually to the commission their planned production levels and schedule for turnarounds and planned maintenance for the following 12 months, by month and by finished product." No clarity or direction exists to identify the optimal submittal date each year that would be properly sequenced to be aligned with the refinery information provided to the Division of Industrial Relations.
- **Section 23555(8)** is unclear if operational costs are intended to include on the costs associated with refining or also include the distribution, marketing costs associated with bringing product to spot pipelines sales, unbranded, branded wholesale rack

and DTW sales. Net margin will also artificially inflate the appearance of profits if distribution costs outside the refinery are excluded. Furthermore, costs do not include the purchased gas costs that may be needed to be consistent with Section 25355.5(a)(1) definition of Gross gasoline refining margin excluding state program costs. In addition, purchase gasoline gas costs need to be included to match corresponding revenue generated in associated spot pipeline sales, unbranded, branded wholesale rack and DTW sales.

- **Section 25355.5(l)** and **Section 25355(a)(2)** have a definitional mismatch. The definition of "gross gasoline refining margin" as currently defined in Section equals the difference, expressed in dollars per barrel, between the average price of wholesale gasoline sold by a refiner in the state and the average price of crude oil received by the refinery. SB X1-2 does not propose changing this definition. Rather, SB X1-2 adds a second definition, the "gross gasoline refining margin excluding state program costs" which equals the difference, expressed in dollars per barrel, between the average price of wholesale gasoline sold by a refiner in the state and the average price of crude oil received and refined gasoline imported by the refinery, less state program costs (low carbon fuel standard and cap-at-the-rack costs). The first measure of "gross gasoline refining margin" is reported to the CEC by refineries; while the second is calculated by the CEC monthly based on data received. It is unclear why imported gasoline costs are part of the equation for the CEC calculation of "gross gasoline refining margin," but not the value as reported by the refiners. Such a difference feels easily resolvable, but without clean-up or clarification could lead to confusion – especially since both gross gasoline refining margins, as reported by the refineries and the one calculated by the CEC are required pursuant to SB X1-2 to be published on the CEC's website within 45 days of the end of each calendar month. Without adjusting these definitions, the two values may be inaccurately represented as divergent.

- **Information Technology (IT)/Security and Confidential Business Information**
  - Regulated entities must know if the CEC will have specific data output formatting requirements to inform software design parameters.
  - Regulated entities will need to know how soon any dedicated data reporting portal will come live or what alternative methods will be available for reporting purposes.
  - Regulated entities must know if there will be dedicated staff and/or a dedicated email address to address questions regarding the reports to be filed.
  - Will CEC have a notification process for regulated entities who do not submit complete data and, if so, what form will that process take? A grace period should be factored into such a process to allow for compliance.
  - Is the CEC confident, and how so, in the capabilities of its IT system to handle the market sensitive data and other reporting data to be collected under SBX1-2?
  - How will the CEC ensure confidentiality of the sensitive data provided to the Commission under SBX1-2?
  - What steps will CEC take to identify and mitigate any breach of security?
  - Would the CEC be willing to engage a third party to monitor and ensure stringent IT security measures to protect data reported?

- Regulated entities must be apprised of the technical specifications and parameters of the IT security system, process and protocols that will be employed to protect confidential business information prior to uploading such data into the system that is ultimately deployed.
- Regulated entities must ensure that the IT Security System/Technology that is implemented is implemented across all agencies that will have access to the information.
- Regulated entities need clarity around which agencies and third parties will have access to Confidential Business Information.

- **Stakeholders**
  - **Section 25354(b)(6)** introduces new obligated reporting entities of "port operators" and "pipeline operators," to report their capacities for all pipelines and ports used to transport refined gasoline. It is unclear whether port operators and pipeline operators possess this information.
  - **Section 25354(i)(2)(F)** may create a new obligation for "oil refiner, oil producer, petroleum product transporter, petroleum product marketer, petroleum product pipeline operator, and terminal operator" to report each week "copies of all contracts or agreements entered into, or amendments to contracts or agreements, with other oil refiners, oil producers, petroleum product transporters, petroleum product marketers, petroleum product pipeline operators, terminal operators, or any other entity that trades in petroleum products whether or not those entities take possession of petroleum products, as designated by the commission, during the monthly reporting period, along with records of every transaction made under those contracts or agreements and the prices charged for those transactions." It is unclear whether all entities required to report would be able to adequately comply with reporting likely thousands of contracts that will likely vary in length.
  - **Section 25354(k)** introduces new reporting entities of "nonrefiners, such as proprietary storage companies, that commercially trade in gasoline, gasoline blending components, diesel fuel, or renewable diesel fuel not subject to contractual supply obligations". It is unclear who these "nonrefiners" are. The term "refiner" is also vague as it is unclear if this means only someone who owns storage and then would report what it holds in its storage facilities.

SB 1322 Items Requiring Clarification Through Rulemaking
The bulleted sections below describe areas of statute that still require additional clarity and would benefit from a rulemaking process:

- First, the term "gross gasoline refining margin" is itself unclear. If the term is meant to be the summation of Section 25355 (b)(1)-(4), then certain compliance issues must be considered.
- Alternatively, if "gross gasoline refining margin" is intended to mean something different than the summation of Section 25355 (b)(1)-(4), refiners will need additional clarity before attempting to quantify associated costs for Low Carbon Fuel Standard and Cap-and-Trade programs compliance in dollars per barrel as initially requested. An agreed-upon benchmark derived during the rulemaking could be a better approach.
- Section 25355 (b)(3) references the "quantity of wholesale gasoline sales." If this term is not adequately defined or is inconsistently applied, such as by some refiners including spot

pipeline sales, the result could be the improper "double counting" of these volumes because such volumes could be resold.

- Section 25355 (b)(1) and (2) reference both "received" crude oil volumes and "received and intended to be refined during that month" crude oil volumes which can have different interpretations. First, these two characterizations of crude oil volumes are not the same due to timing differences between purchasing and processing. Second, it is unclear whether "received" volumes include or exclude purchased crude oil that has not yet arrived at a refinery.
- Section 25355 (b)(4) is unclear as to whether stationary refinery Cap-and-Trade obligation costs should be included.
- It is unclear if the margin cap will apply to a regulated company's margins in California or a company's margins overall and how a company's wholistic profit and loss statement and financial position fits into the formula used for determining appropriate profit margins in California.
- The formula that will be utilized to analyze the data being provided and to make the determination that a margin cap should be imposed is unclear and lacks specificity.

Additionally, it is important to note that the components included in SB 1322 that appear to be used to calculate a "gross gasoline refining margin" fail to accurately represent refining profits, because they exclude significant costs incurred by refiners including, but not limited to: federal renewable identification numbers (RIN) obligation costs, other refinery costs (e.g., electricity, natural gas, chemicals, maintenance, hydrogen, other intermediate oil products), capital investments, logistics costs, additive costs, and gasoline purchases. In other words, the use of gross margin, particularly on one product line in a complex operation, artificially inflates profits, rather than reflecting actual profit margins. This runs counter to providing the public with facts.

The list above excludes other concerns (such as regulatory compliance costs) – but is a sampling of the multitude of SB 1322 issues that still needs clarification, which should be addressed through a formal rulemaking. That would be the best mechanism through which all stakeholders will have an opportunity to provide input on SB 1322 implementation. It will allow for discussion on what new data is needed to comply with the law and which can be provided by the parties under antitrust laws with the proper protections, and how the required data will be used and to who it will be made available. Other considerations include avoiding any future misunderstandings or misuse of publicly available data. We want to ensure a consistent interpretation of SB 1322 by privately held, competing companies subject to SB 1322 that each have different assets and market positions and by CEC staff.

ATTACHMENT B

ITSP Risk Questionnaire for CEC

1. Has an information security governance framework been established, maintained and monitored? Which industry standard information security framework is this based on (e.g., ISO/IEC, NIST, CIS)?

2. Is a review or audit of framework controls performed regularly? Please provide an example audit report (a redacted report is acceptable).

3. Is a rigorous information risk analysis undertaken for each critical information system? Which industry standard risk analysis framework is this based on (e.g., ISO/IEC, NIST, CIS)?

4. Is an information security review or audit of all third-party service providers performed? Please describe the process.

5. Have third party penetration tests been performed? Please provide an executive summary or report of the results (a redacted report is acceptable).

6. Are key information security performance indicators (such as patch status, results of risk assessments, internal audits, and incident documentation) or metrics reported on a regular (e.g. monthly) basis? Please provide sample information security management status report (a redacted report is acceptable).

7. How long does the CEC intend to keep the data provided? Will all provided data be purged when it is no longer needed and will companies be notified when it has been removed or shared beyond the scope of the law requirements?

8. Are systems and networks which host the repository monitored continuously and IDS/IPS systems employed to detect/prevent security events?

9. Do you have a Security Operations Center or alert on-call staff 24/7?

10. Is an approved method for identifying, maintaining and protecting Personally Identifiable Information (PII) applied to ensure that information about individuals is used in compliance with legal and regulatory requirements for information privacy?

11. What methods(s) are used to transfer data into the repository? (e.g., API, FTP, other?)

12. Is all data encrypted both at rest and in transit? What encryption algorithms will be used? Who will generate and hold the encryption keys?

13. What restrictions will be in place to prevent downloading or copying of data to unauthorized devices and users? Will users be able to access the information using mobile devices?

14. Are backups of the repository taken (or is it replicated to another repository)? Where are they stored and how are they protected?

15. Describe the breach notification process? Would notifications to customers in the event of a breach be within 24 hours or less?

16. Is there a patch management process in place? Please provide patching timelines for 0-day, critical, high, and medium vulnerabilities.

17. Do the administrators of the repository have malware prevention process in place (e.g. antivirus)? What is the timeline for definition updates? “

18. Are wireless networks secured according to an industry best practice including segmentation of guest and corporate wireless networks and encryption?

19. Is multi-factor authentication required for all users who will have access to the data (including cloud administrators)? Is just-in-time privilege elevation enforced for cloud administrators? What authentication protocols are used?

20. Are all user activities continuously logged, monitored, and reviewed on a regular basis? Are logs aggregated into a centralized Security information and event management, (SIEM)?

21. Are secure coding best practices employed by the developers of the portal/repository? What best practice standards are used? Are static and dynamic code tests performed on the portal/repository?

22. Describe in detail how each company’s data is separated from other companies’ data. Will separate encryption keys be used for each company’s repository?

23. Describe your access control policies and procedures in detail (both for reading and writing to the repository) Is access restricted to authorized locations and users? If so, how often is the access reviewed?

24. Describe in detail what controls are in place to prevent exfiltration of Company’s data from your systems.

Catherine H. Reheis-Boyd
President and CEO

September 11, 2023

California Energy Commission
Docket Unit, MS-4
Docket No. 23-SB-02
715 P Street
Sacramento, California 95814

Submitted via email to docket@energy.ca.gov

RE: WSPA Comments Regarding SB X1-2 Transportation Fuels Assessment Workshop [Docket #23-SB-02]

Thank you for providing an opportunity to comment on the California Energy Commission's (CEC or Commission) August 17, 2023, workshop to inform implementation of the Senate Bill (SB) X1-2 (2023) Transportation Fuels Assessment report to the California State Legislature. The Western States Petroleum Association (WSPA) is a non-profit trade association representing companies that import and export, explore, produce, refine, transport and market petroleum, petroleum products, natural gas, renewable natural gas and renewable diesel, hydrogen, and other energy supplies for California.

WSPA offers comments on issues presented for, or discussed during, the workshop. Underpinning these are, ***first***, the need to recognize that California has evolved into a "fuel island" – the State is effectively disconnected from the national fuels market while continuing to adopt policies that compound the issues SB X1-2 seeks to address: ensuring the adequate, affordable, reliable, safe, and equitable supply of petroleum and alternative transportation fuel supplies for all Californians. What follows is a more detailed explanation of this situation and, ***second***, comments on market-related issues; ***third***, comments on the Lead Commissioner's opening remarks regarding the possible imposition of a gross margin cap and penalty; ***fourth***, comments on how best to frame the Transportation Fuels Assessment; and, ***finally***, preliminary responses to the workshop questions. Our responses to potential policy options represent an initial commentary on what we think these could mean for California's petroleum market based on the limited information presented by the CEC and should not be construed as an endorsement of any option. We look forward to providing additional information to the CEC as implementation of SB X1-2 moves forward.

I. CALIFORNIA IS AN ISOLATED FUELS MARKET

California is a "fuel island" due to decades of constraining land use and permitting decisions paired with policies explicitly intended to reduce the State's supply and consumption of fossil fuels (*e.g.*, in-State oil production bans, internal combustion engine bans) – even as these fuels remain in high demand. Policies such as requiring a specialized CARBOB gasoline formulation, federal Jones Act maritime requirements, and strict seasonal transition standards create even more operational complexity, creating an extremely challenging California fuels market for in-State, out-of-State, and international suppliers. When coupled with California's isolated infrastructure, there are strong *dis*incentives for companies to make the long-term investments necessary to maintain California's current level of refining capacity.

This was not always the case. California was once a domestic gasoline manufacturing hub with abundant local production capacity to affordably supply in-State demand, as well as the demand of adjacent states. The reduction of in-State refining capacity has happened while the State's own policies artificially constrain in-State production and refining to meet demand and *without* having the benefit of ready access to additional domestic supplies.

California is now unable to supply all its own gasoline to meet demand and is more dependent on the global market. The CEC's 2005 Independent Energy Policy Report (IEPR) – a report that is now nearly 20 years old – identified even then that, "California's petroleum infrastructure operates at near capacity. Breakdowns and outages at in-State refinery and pipeline facilities quickly tighten gasoline and diesel fuel supplies and create market volatility. Since California is not directly connected by pipeline to other domestic refining centers, in-State refiners cannot readily procure gasoline, diesel, and other blending components when outages do occur. This contributes to higher and more prolonged price spikes."

While there is a *domestic* gasoline manufacturing hub – specifically along the Gulf of Mexico – there are no economical means of transporting enough gasoline from the Gulf Coast to California. Nor is there a pipeline to move gasoline from that major refining hub to the West Coast. The other very expensive and inefficient alternative to move domestic product to California, via marine transportation, is constrained given limits with efficiently moving very large tankers through the Panama Canal. And it is normally economically prohibitive for new U.S. vessels to supply California from the Gulf Coast due to federal Jones Act and Panama Canal restrictions; California's seaborne trade must therefore be sourced from *foreign* refineries, typically in Asia, thousands of oceanic miles farther away than otherwise readily available domestic supplies.

It now takes West Coast suppliers, on average, 30-45 days (for imports from Asia) to import alternative fuel sources overseas following significant refinery outages. For example, global shipping markets (*e.g.*, availability and freight rates) continue to be dramatically disrupted because of the Russian invasion of Ukraine. Such an unforeseen global event – the largest European land war since World War II – has had a significant effect on the global crude oil commodity market; California consumers, due to the "fuel island" effect outlined here, were especially susceptible to the resulting supply disruptions and price swings.

California's challenging regulatory environment continues to send a strong signal to both refining and production companies that their future in the State is very limited. The overall expense of doing business in California – including operating, capital, and labor expenses – is far higher than in most other states. For example, the California Air Resources Board's (CARB) new "At-Berth" Regulation will further limit the number of calls and/or availability of tankers that can call on California's ports beginning in 2025 – the very same facilities that will need to absorb the delivery of increasing imports due to artificially constrained in-State production and refining policies. The growing costs of California's climate policies and programs are further compounded by multiple layers of federal, regional, and local regulations; that add costs and do impact a fragile, volatile, and constrained California fuels market. We are concerned, for instance, that SB X1-2 compliance obligations appear to be discouraging finished product and component imports into California because counterparties may be unwilling to complete the additional requirements to comply with California's unique new regulation – including to obtain information that could be used to potentially cap gross revenues. Consequently, supplying

California remains difficult, making the State further at risk of future market volatility that will only worsen as additional restrictive State policies take effect or are approved.

All of this contributes to making California an extremely difficult State in which to operate – and, therefore, invest. As some State agencies and legislators continue to champion the closure of refineries, companies that own and operate these refineries could become reluctant to make long-term investments required to operate these needed facilities because the State's own policies disincentivize doing so. It is therefore challenging for California's upstream and downstream assets to compete for investments. *Dis*incentivizing investments in California further constrains our fuels market.

A simple fix to California's supply and demand imbalance is highly unlikely as a series of actions would be needed to resolve California's "fuel island" effect. Because of the complex nature of these issues, we believe longer-term solutions will be challenging, but WSPA would like to work with you to evaluate options for reliably increasing the supply of affordable fuels to California.

II. NEED TO IMPROVE MARKET STABILITY AND ADDRESS MARKET VOLATILITY

The transportation fuels market is global and dynamic. And California's boutique fuels market, as described above, is fragile and more sensitive to market volatility. We agree with the CEC that price spikes are predominantly caused by California's geographic isolation, regulatory bottlenecks, and refinery outages – which are made more acute by regulations and policies that disincentivize capital investments. Indeed, the CEC had identified global supply issues, refinery outages, and taxes and regulations as the causes of price spikes during fall 2022.[1] That conclusion is consistent with the CEC's research dating back nearly 20 years.[2]

Multiple actions and collaborative efforts between policymakers and the industry are necessary to resolve California's long-standing "fuel island" effect. For each energy transition policy implemented, policymakers should ask if the action will encourage longer term investments in gasoline production, distribution, and retail services that Californians will still need for decades to come. If the answer is "No," the State should work with industry stakeholders to determine reasonable solutions to avoid unintended consequences. Because of the complex nature of these issues, we are willing to work with the CEC to evaluate options for increasing the supply of fuels to California, such as:

1) **Choosing policies that encourage investments in adequate, affordable, reliable, safe and equitable transportation liquid fuel supplies.** This would require clear and consistent policies that support resource development, streamline permitting processes for upstream and downstream facilities, support liquid fuel infrastructure development and protect in-State refining, distribution, and retail investments.
2) **Exploring what regulatory barriers can be mitigated during market volatility.** This could include utilizing waivers to allow for the early seasonal transition of CARBOB standards or working with the Federal government to lift Jones Act requirements during exceptional events (*e.g.*, weather, geopolitical, etc.). Please note these actions are

[1] California Energy Commission, *California Gas Prices*, Presentation at November 23, 2022 California Energy Commission Hearing, at 43.
[2] See generally California Energy Commission, 2005 Integrated Energy Policy Report.

levers that may help mitigate temporary supply constraints caused by such volatility, rather than prevent market volatility.

However, some actions can make California's gasoline market ***even more*** susceptible to market volatility, such as:

1) **Imposing a vague, arbitrary maximum gross gasoline refining margin and a subsequent penalty.** Doing so would likely have immediate harmful impacts on gasoline prices and economic activity throughout the State. It may likely lead to more severe gasoline shortages by disincentivizing California production (since refiners may choose not to sell finished product in California to avoid exceeding the cap), and likely create shortages of *other fuels* refiners produce – such as jet, diesel, and other transportation fuels – as these fuels are produced as part of the same refining process as gasoline. Because refiners cannot feasibly reduce the amount of CARBOB gasoline produced without *also* reducing the production of these other fuels, a cap could reduce those fuel supplies too. This could likely mean less available refined transportation fuel and more market volatility for California consumers. Moreover, with less capital on hand to maintain and modernize California's refining infrastructure, including requirements to meet emission reduction projects – we are concerned that this could lead to less reliable operations and potentially reduced refinery capacity, thus exacerbating the supply situation. In addition, if the gross gasoline refining margin is calculated, the amount must be evaluated on an annualized average basis to account for market volatility and periods when margins turn negative.

2) **Increasing California's susceptibility to market volatility.** The State is especially sensitive to market disruptions because of its isolated infrastructure and unique fuel blend. As CEC has recognized, temporary changes in fuel costs result from the forces of supply and demand – not market manipulation or price gouging. But, as we have historically seen, the market corrects itself; as higher prices attract more fuel supply into the State, costs naturally drop. However, a margin cap could tend to decrease the amount of gasoline sold in California and prevent this natural correction, and thus could increase the frequency and length of cost increases due to supply disruptions. This is historically because price spikes tend to reduce demand and subsequently increase supply (from imports). Eliminating the market's natural ability to restore equilibrium could result in widespread supply outages (which have been avoided to this point).

3) **Further increasing reliance on gasoline imports.** SB X1-2 would encourage increased reliance on imported gasoline. Although California's marine terminal infrastructure is already near capacity today, and the ability to import additional product into the State will likely be further reduced if refinery capacity diminishes. Furthermore, not all marine facilities are connected to the pipeline distribution systems; gasoline imports into California would come from overseas, not from the United States, due to the lack of Jones Act vessels and Panama Canal constraints. Relying on overseas imports, if they are available in sufficient quantity and quality, would likely result in higher transportation costs and increase the length of supply shortages due to transit times. In addition, importers will need to cover the cost of crude refining, transportation and throughput expenses likely resulting in higher – rather than lower – costs to Californians.

4) **Not accounting for the cyclical nature of the refining industry.** On average, returns on capital employed in the refining industry are lower than the returns in many other industries. In 2020 and 2021, California's refiners lost billions of dollars as prices plummeted due to the COVID pandemic. In contrast, periods with higher margin allow refiners to make necessary maintenance and regulatory-driven investments to operate refineries safely and reliably, to reduce emissions, and to improve efficiency. These activities can cost hundreds of millions of dollars annually for a single refinery. However, SB X1-2 threatens to impose a penalty on *gross*, rather than *net* margins – thereby undercounting the cost of these investments and potentially reducing the amount of capital available for maintenance and improvements. If that capital decreases, refineries may not be able to operate reliably.

5) **Not accounting for product availability and jobs impacts.** These are other important ramifications to consider. Refineries are not designed to make a single product from each barrel of oil. To be efficient and functional, refineries produce a variety of different products demanded by the market, which are determined by each crude's content. While a margin cap on gasoline could mean that refineries would produce less gasoline for California to avoid penalties, this would also necessarily mean a reduction in production of the jet and diesel fuels needed in California. Furthermore, most jobs at most California refineries are union labor, and there are typically hundreds of additional contract workers onsite helping to maintain a given refinery. To the extent a margin cap discourages refining production and investment in California, it also threatens the long-term job security of thousands of Californians.

6) **Not accounting for impacts in other states.** California is the main hub for oil and gas flowing to Arizona and Nevada. Decreasing the incentive to invest in California's oil and gas infrastructure through a margin cap could increase long-term prices in California, as well as in Arizona and Nevada. SB X1-2 directs the State to defray these increased costs for *California* consumers, but consumers in Arizona and Nevada would be left to bear the full cost of the policy.

III. WSPA RESPONSE TO CEC VICE CHAIR SIVA GUNDA'S COMMENTS REGARDING SETTING A MAXIMUM GROSS GASOLINE REFINING MARGIN

The CEC has been directed to investigate if there is a need for a maximum gross gasoline margin and penalty. Based on years of refining experience, and decades of real-world evidence of how California's transportation fuels market has consistently reacted to fuel supply constraints, WSPA believes a cap on gross margin will likely further decrease California's gasoline supply and increase gasoline costs due to an even tighter market. This could place an even larger burden on Californians – especially upon those least able to afford increased costs.

WSPA is concerned that the imposition of a gross refining margin cap and penalty would likely reduce the supply of transportation fuels for Californians as refiners could seek to stay below knowingly incurring (and publicly reporting) a State-imposed penalty. This should be avoided given the already constrained state of California's fuels market. With the substantial new market data now being collected by the CEC, we encourage the Commission to carefully consider how a margin cap would impact the availability of an adequate, affordable, equitable, reliable, and safe supply of needed transportation fuels for Californians as directed by SB X1-2.

Neither the CEC nor California consumers are served by an incomplete or inaccurate picture of the State's petroleum market. Unfortunately, in the absence of any guiding rulemaking on the subject to date, the collection of information so far under SBX1-2 has resulted in an inconsistent and incomplete patchwork of information. Some information the State requested from the industry to date is easily open to disparate interpretation, reflects data not directly relevant to the market or consumer prices, presents an unreliable representation of industry revenue, or fails to capture the true costs of supplying the California market. We continue to strongly encourage the CEC to conduct the formal rulemaking necessary to solicit clarifications on what information should be collected to best inform its decisions not only about the wisdom of a margin cap, but also about how best to ensure equitable and affordable transportation fuel supplies for all Californians.

Without a rulemaking to resolve data consistency issues, setting an arbitrary – and potentially too low – maximum gross refining margin could *decrease* the availability of refined gasoline for California consumption to the detriment of all Californians. Contrary to some policymakers' belief that refiners can adjust prices to manage a margin cap, there is no straightforward formula for how to adjust ***daily*** prices to keep them within a ***monthly*** profit cap. A SB X1-2 margin cap regime would be extremely difficult to comply with, with refiners potentially penalized for factors beyond their control. In addition, levers available to manage margins may be to reduce not *price* but rather *supply*; as a result, retailers could be forced to either increase prices or run the risk of running out of gasoline. It is also possible that, as a result of a penalty, refiners may end up producing gasoline at a loss in some months.

It is therefore critical that CEC evaluate the potential impacts and unintended consequences of adopting such a cap and assess whether the actual market evidence indicates that such a cap will do anything to help California consumers. The lesson of the past 30 years in California is that lasting consumer relief can only be achieved by addressing the underlying fundamental market variables. Even third-party and the State's *own* experts have concluded that a cap on refinery margins has the potential to *harm consumers and drive prices up* by aggravating California's increasingly structural supply constraint issues – leading to the extreme gasoline price spikes the CEC is tasked with preventing and mitigating. The CEC's own Petroleum Market Advisory Committee, in 2016, had dedicated meetings to supply issues facing the California market and how supply constraints appeared to be getting worse. The Committee also discussed the need to be careful with State regulations to *not* unnecessarily decrease refining capacity, as well as a concern more generally to minimize unintended consequences of any new policy mechanism.[3,4]

To the extent that the Commission is considering a maximum gross gasoline refining margin and penalty under California Public Resources Code (PRC) section 25355.5, WSPA believes that it either does not have adequate information to assess a cap's impact on Californians or may be relying on incomplete, inconsistent, and therefore likely inaccurate information. Despite industry's best efforts to comply, CEC's information requests to date have been ad hoc, do not explain how to interpret new terms introduced by SB X1-2, and have not been informed by the CEC's institutional experience in defining and administering specific reporting obligations. For example, under PRC section 25355, the "[g]ross gasoline refining margin" does not accurately

[3] February 8, 2016 Petroleum Market Advisory Committee (PMAC) meeting transcript (page 203) https://www.energy.ca.gov/data-reports/planning-and-forecasting/petroleum-market-advisory-committee.
[4] PMAC Final Report, November 2014 to November 2016

reflect real-world refinery costs and profit margins, and any penalty based on it would be poorly targeted and could have unintended consequences. These issues necessarily limit how useful CEC's information requests can be. WSPA has advised the CEC that rulemaking is required to provide guidance to industry on the types of information required; to ensure the data the agency receives is consistent, reliable, and useful in shaping California's energy future; and to properly inform the Commission on the potential consequences of a maximum gross gasoline refining margin.

SB X1-2 did not resolve the ambiguities that existed in section 25355, but rather added additional ambiguous terms to a statute that already contained novel and open-ended reporting requirements and terms. For example, SB X1-2 added the term "Net gasoline refining margin" as a separate figure required to be reported, defined as "gross gasoline refining margin minus the refinery's operational costs.[5]" The statute includes a nonexclusive list of "operational costs," but does not suggest what other categories of costs may or may not fit the definition of or indicate how to allocate these "operational costs" among different categories of finished product.[6] Refiners make several products with the same feedstocks and crude oil – such as jet fuel, diesel, heating oils, and the different grades and blends of gasoline (including gasoline that meets California's standards). Many "operational costs" – such as the costs of refinery maintenance, employee salaries, and marketing costs – cannot be easily allocated among those products, and the statute does not provide a consistent, accurate method for doing so. As WSPA has previously stated, those original terms can be reasonably interpreted in multiple ways and thus will likely not produce consistent results across refiners.

There are other issues with the statute that should be addressed before considering the imposition of a margin cap. Even though the "net gasoline refining margin" is a better (albeit still misleading) estimate of refinery profits, section 25355.5(b) instructs the Commission to consider a cap based on the "gross gasoline refining margin." In other words, while the statute reflects legislative recognition that the "gross gasoline refining margin" is flawed and can be improved by accounting for operational costs, it still authorizes punishment of refiners based on this less accurate number. Any process by the Commission to determine whether to penalize refiners under section 25355.5 must account for this discrepancy. Too low of a cap for refiners on the "gross gasoline refining margin" could effectively mandate that a refiner take a loss to avoid a penalty, and/or result in the penalty dipping into operational costs – or worse, determining that these draconian market restrictions do not justify continued operation in California.

Additionally, SB X1-2 does not account for the critical differences in configuration, production, operations, distribution, and marketing between refiners. For example, the statute treats refiners differently based on their distribution models; i.e., refiners that sell wholesale gas to affiliated stations may see a higher "volume-weighted average price of wholesale gasoline" than other refiners, and thus, higher gross and net margins for reporting purposes – all simply by virtue of their distribution model. But differences between distribution models do not accurately reflect real-world differences in profitability of refinery operations, and it makes little sense to unfairly penalize (or reward) refiners for distribution models formed decades before, in a statutory regime supposedly aimed at addressing excessive profits from refining, not from distribution. Indeed, refiners' profits and losses shift over time and are based on a multitude of factors, many of which are not fairly captured or mentioned in the statutory definitions.

[5] PRC § 25355(a)(2), (b)(9)
[6] *Id.* § 25355(a)(3)

In the absence of CEC guidance, refiners are likely to employ different methods, resulting in inconsistent reporting. Moreover, looking at data for an isolated period can provide an unrepresentative and inaccurate view of refinery profitability. The Commission, in collaboration with the industry and other stakeholders, should create a single accounting process that addresses the full slate of products refiners make and the costs related to producing that slate. And it should not rule on the propriety of a profit cap until it clarifies this critical informational input.

The CEC should not move forward with any margin cap before it can fully analyze and account for these discrepancies. The Commission will otherwise not receive fairly comparable information necessary to fulfill its statutory mandate to determine whether a margin cap can benefit California consumers. So far, the Commission has not determined conclusively how to navigate these issues. WSPA asked the Commission to initiate a rulemaking regarding the statute, as amended, because "key terms lack clarity, are contradictory, and/or may have multiple interpretations, which could thereby render reporting inaccurate, inconsistent, and open to misinterpretation."[7] Other industry groups joined in asking the Commission for guidance too.[8] The Commission did not provide clarity, and instead instructed industry participants to refer to other regulatory definitions and "language otherwise commonly understood in the industry."[9] The Commission also denied the requests for rulemaking on June 1, claiming that SB X1-2's "terms . . . are clear as written, and, accordingly, may be implemented without delay."[10] For all the reasons stated above, this is not the case.

IV. INPUT ON THE TRANSPORTATION FUELS ASSESSMENT REPORT

WSPA appreciates the opportunity to inform development of the first triennial Fuels Assessment Report. The statute is clear in requiring the CEC to identify methods to ensure a reliable supply of affordable and safe transportation fuels while evaluating costs, supply and employment conditions, and potential refinery closure impacts, as well as costs and cost-effectiveness. As a basis for the report, we recommend that the CEC use the following set of guiding questions to frame and guide this report:

- How will California ensure the production and delivery of reliable *and affordable* transportation fuels for all Californians that need them?
- How does California plan to address the serious and continuing structural supply constraints for crude oil and gasoline in the world's third largest fuels market?
- How will California continue to meet demand if refining capacity diminishes, given that few out-of-State refineries can produce fuels that meet California's strict specifications (and those that can generally require more than a 30-day waterborne transit time to reach marine terminals that are already at capacity)?
- How is California going to encourage ongoing capital and operational investments to keep our existing transportation fuels system working as the proposed energy transition evolves?

[7] Catherine H. Reheis-Boyd, Western States Petroleum Association, Petition for Formal Rulemaking—Implementation of SBX1-2 & SB 1322 at 2, 8–9 (May 11, 2023)
[8] See Elizabeth Graham & Alessandra Magnasco, California Fuels & Convenience Alliance, Petition for Formal Rulemaking—Implementation of SB X1-2 (May 18, 2023); Michelle Orrock, bp America Inc., Petition for Formal Rulemaking—Implementation of SB X 1-2 (May 30, 2023).
[9] Letter from Drew Bohan, Executive Director, California Energy Commission, to Petroleum Industry Representatives (May 30, 2023).
[10] Order 23-0531-11, California Energy Commission (June 1, 2023)

- How will the State reconcile artificially constrained in-State crude oil production (due to State policies) that outstrips CARB's assumed crude oil production decline rate in the 2022 Scoping Plan Update?[11]
- How do California's policies impact fuel costs to all segments of the population under each scenario?

WSPA recommends that – before evaluating new policies to layer on top of existing ones – the CEC first quantify the relative impact of current regulations on California's fuel supply. This includes identifying infrastructure bottlenecks in our ports, pipeline systems, and elsewhere within the supply chain to determine where there are capacity constraints. By first evaluating these systemic issues, the CEC may then be able to identify important fixes and any unintended consequences of policies intended to reduce the State's fossil fuel consumption. These are strong *dis*incentives to make the required investments needed to maintain California's remaining refining capacity, which should be evaluated to assess their potential drawbacks on the fuels market.

The CEC should also include multiple fuel demand and cost scenarios that incorporate low-, medium-, and high-demand scenarios for ongoing fuel consumption, under multiple time horizons, given the known transportation electrification uncertainties already identified by CARB in the 2022 Scoping Plan Update's uncertainty analysis.[12] This will help ensure the CEC begins with a strong base of knowledge to build from as it works through developing solutions to address California's daily fuel constraint.

Next, we recommend that serious attention be given to the negative impacts the imposition of a maximum gross gasoline refining margin and a subsequent penalty could have on the market. The prior section offered a more detailed explanation of the potential impacts and unintended consequences of adopting such a cap and whether the actual market evidence indicates that such a cap will do anything to help California consumers.

Equity and fuel affordability also must be a central part of the CEC's analysis. As CARB and the CEC itself has recognized, millions of internal combustion engine vehicles (including hybrid vehicles) – and therefore, petroleum-based fuels – will be used and needed by Californians for decades to come. Predicting the market is impossible, but regardless of where actual market demand ultimately settles, there should be little disagreement that California needs to ensure adequate fuel supply for those citizens who will continue to rely on internal combustion engine vehicles. Not doing so could force economic harm on some of California's most vulnerable citizens, those who cannot afford advanced electric vehicles, and for whom gas price increases or supply shortages can have a devastating effect. WSPA urges the CEC to not be bound only by scenarios that "must meet" ambitious climate policies while failing to plan for scenarios that do not anticipate material factors in California's transportation market (e.g., lower than expected Zero Emission Vehicle (ZEV) adoption rates, pressing affordability issues that worsen inequity issues, energy infrastructure constraints, delays or failures, and critical mineral and other supply chain shortages).

During the workshop, CEC staff presented multiple policy concepts for mitigating volatility in California's fuels market. Because California requires a boutique blend of fuel, along with

[11] https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents
[12] https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-appendix-j-uncertainty-analysis.pdf

meeting a multitude of regulatory requirements while navigating infrastructure constraints, the State has an extraordinarily constrained market. We therefore recommend that, before evaluating any new policies, CEC first conduct an analysis to quantify the relative impact of current regulations on California's fuel supply. This should further include identifying infrastructure bottlenecks (e.g., in ports and pipeline systems) to determine capacity constraints. By first evaluating these systemic issues, CEC may be able to identify important fixes and any unintended consequences of policies that impact the fuels market. By first conducting analysis of existing issues, CEC will start with a strong base of knowledge to build from as the state works its way through the development of solutions to this long-standing problem.

We appreciate that the CEC seeks policy options towards ensuring "a reliable supply of affordable and safe transportation fuels in California." WSPA believes that California policymakers must ensure that the transportation fuels sector avoids a "Diablo Canyon moment," as we have seen in the electricity sector. There, the State has had to make significant policy reversals to ensure the reliable operation of California's electric grid, following multiple years of rolling blackouts. We have an opportunity here to avoid repeating that mistake.

As part of this assessment, the CEC should include multiple demand and cost scenarios for ongoing fuel requirements, given the uncertainties outlined above. In WSPA's comment letters[13,14] to CARB in developing the 2022 Scoping Plan Update, WSPA repeatedly expressed concerns with CARB's reliance on a ZEV-only approach in pursuing California's greenhouse gas and air quality goals within the transportation sector because it failed to evaluate more cost-effective air quality and emissions reduction benefits that other technology options, such as near-zero emissions vehicles and low-carbon and renewable fuels, could deliver. For example, Ramboll's case studies of the heavy-heavy duty truck fleet[15] and the light duty automobile fleet[16] demonstrate that there are alternate pathways using renewable and other low carbon fuels that can dramatically reduce transportation sector carbon emissions without ZEV mandates. We request the CEC undertake this analysis and consider the benefits of utilizing these technologies for improving air quality while providing more affordable and technically feasible transportation fuel options – options that the State acknowledges will be needed for decades to come.

Stillwater Associates has also studied projected fuel demand based on CARB's work on the Mobile Source Strategy.[17] That analysis showed that, if California's fleet changes as projected, "the fuel projections developed by CARB show gasoline demand to be reduced by 66% and 92% below recent levels by 2035 and 2050, respectively and liquid diesel demand to be reduced by 24% and 60% below recent levels by 2035 and 2050, respectively. By contrast, the fuel projections developed in Stillwater's Scenario show gasoline demand to be reduced by 17% and 24% below recent levels by 2035 and 2050, respectively and liquid diesel demand to

[13] WSPA. 2022. Comments on the Draft 2022 Scoping Plan Update. June 24. Available at: https://www.arb.ca.gov/lists/com-attach/4416-scopingplan2022-BnEAdVQlBTdRCAZn.pdf. Accessed: June 2023.
[14] WSPA. 2022. Comments on the Final 2022 Scoping Plan Update and Appendices. December 15.
[15] The Ramboll HHDT study is available here: https://www.arb.ca.gov/lists/com-attach/78-sp22-kickoffws-B2oFdgBtUnUAbwAt.pdf.
[16] Ramboll. 2022. Multi-Technology Pathways To Achieve California's Greenhouse Gas Goals: Light-Duty Auto Case Study. Available as Attachment D at: https://www.arb.ca.gov/lists/comattach/477-accii2022-AHcAdQBxBDZSeVc2.pdf.
[17] "Possible Market Implications of California's Efforts to Ban Internal Combustion Engines (ICE)," Stillwater Associates LLC, December 31, 2021

increase by 15% and 28% above recent levels by 2035 and 2050, respectively. The gasoline demand reduction is about four times greater for CARB's [Internal Combustion Engine] Ban Case than Stillwater's Case. The diesel demand decrease for CARB's [Internal Combustion Engine] Ban Case is about double the increase projected by Stillwater's Case. These starkly different results have dramatically different impacts on California's fuel value chain and fuel costs over the next thirty years, which are discussed in the rest of this section." The CEC should evaluate options for meeting that fuels demand scenario as part of this assessment.

The CEC must also analyze the current state of California's existing oil and gas infrastructure that is substantially supporting the State's existing energy economy. This analysis must be inclusive of the entire supply chain – upstream, midstream, downstream, and retail/marketing – and should include an analysis of the root causes of infrastructure challenges and related supply issues. WSPA recommends that the CEC utilize CalGEM production data to assess the differential in what CARB has assumed (approximately 3% annual production decline in the 2022 Scoping Plan[18]) versus what CalGEM data has shown (approximately 10-15% decline depending on the data set used).[19] We also recommend the CEC evaluate regulatory barriers preventing needed oil and gas facility maintenance activities, policies and processes that create long-term uncertainties in California's oil and gas industry. It continues to be a critical issue for California gasoline supply that most refineries outside of California cannot produce fuels that meet California's strict specifications.

California produces and refines hydrocarbons available under the strictest environmental policies in the world. Thus, any artificial constraint that reduces in-State supply and production will require that crude oil, intermediates and gasoline be procured from refineries out-of-State and around the world – all facilities outside the jurisdiction of California's strict environmental policies.

We are committed to working constructively and collaboratively to try to identify the factors driving California's high energy costs and how this industry, and our people, can help drive down energy costs for Californians. We must disrupt entrenched beliefs, encourage investment in state-of-the-art lower carbon crude oil production, enhance in-State refinery capacity and critical supply infrastructure, eliminate unnecessary burdens on businesses and, most importantly, create a foundation of mutual respect and collaboration that allows us to work together to help all Californians figure out what needs to be done to ensure that this critically important – and complex – transportation fuels system works for every Californian.

V. WSPA RESPONSES TO INDUSTRY PANEL WORKSHOP QUESTIONS

"What is the leading contributor to price spike risk for transportation fuels in the State?"

As the CEC explained, price spikes are caused predominantly by California's geographical isolation, regulatory bottlenecks, and refinery maintenance issues – which are made more acute by regulations and policies that disincentivize new infrastructure investments. For example, the CEC identified global supply issues, refinery outages, and taxes and regulations as the causes

[18] CARB. 2022 Scoping Plan for Achieving Carbon Neutrality, Page 103. Available at: https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf. Accessed: August 2023.
[19] California Department of Conservation, WellSTAR monthly production data reports, 2018-2023, https://www.conservation.ca.gov/calgem/Online_Data/Pages/WellSTAR-Data-Dashboard.aspx

of price spikes during fall 2022.[20] That conclusion is consistent with the CEC's research going back nearly 20 years, which shows that California's geographic isolation and aging infrastructure are the primary contributors to price spikes.[21]

The markets are still stretched, years later. This means that resupplying California remains difficult, leaving the State further at risk of future price spikes that will likely only worsen as more new restrictive State policies take effect or are pending approvals. For example, CARB's new At-Berth regulation will limit the number of calls and/or the availability of tankers that can call on California's ports beginning in 2025 – the very same facilities that will need to absorb the delivery of increasing imports due to artificially constrained in-State production and refining policies. The growing costs of California's climate policies and programs are only compounded by multiple layers of federal, regional, and local regulations.

Due to these factors, and the relative inelasticity of Californians' demand for gasoline, even relatively small disruptions in supply can have large impacts on fuel costs. As economist R. Preston McAfee explained to the United States Senate, "A 10% shortfall in quantity, which might arise due to a fire in a refinery or a pipeline break, might require a 40% increase in price to clear the market – because consumers continue to drive almost as much, and the refineries cannot produce much more gasoline than they already do. The inelasticity of demand implies that large price swings are normal – small supply disruptions create large price swings. The oil companies do not create such price changes – they are primarily a consequence of factors outside the control of the industry."[22] Similarly, the CEC concluded in 2019 that "refinery outages have an impact on prices" but that apart from "outage-driven spikes, there has been little to no growth in the difference between the United States and California refinery margin."[23]

Compounding these challenges is the overall expense of doing business in California; operating, capital, and labor expenses are much more expensive in California than in most other states.

This contributes to make California an extremely difficult State in which to operate – and, therefore, invest. As some State agencies and legislators continue to champion the closure of refineries, companies that own and operate those same refineries could become reluctant to make long-term investments required to operate these needed facilities because the State's own policies disincentivize doing so.

WSPA reiterates here that nearly three decades of real-world experience, expert analyses, agency inquiries and various court proceedings have yielded no evidence that California's refiners engage in price-gouging, or that price-gouging is the cause of market volatility. Analyzing gas price spikes during the summer of 2022, the CEC concluded that "Refinery Cost & Profit" added up to only 64 cents each gallon – a number that accounted for the *entire* cost of

[20] California Energy Commission, *California Gas Prices*, Presentation at November 23, 2022 California Energy Commission Hearing, at 43.
[21] See generally California Energy Commission, 2005 Integrated Energy Policy Report.
[22] Congressional testimony of R. Preston McAfee, Murray S. Johnson Professor of Economics and former Chair of the Department of Economics at the University of Texas at Austin. May 2, 2002.
[23] California Energy Commission, *Additional Analysis on Gasoline Prices in California* 1–2 (Oct. 21, 2019), https://www.energy.ca.gov/sites/default/files/2019-11/Gas_Price_Report.pdf

the refining process and margins for refiners, meaning *profits* alone were much less than that.[24] Purported market manipulation by refiners has been studied and investigated repeatedly by multiple California Attorneys General, and the result has been that there is simply no evidence that refiners manipulate the supply of fuel to cause price spikes. In 2019, the CEC categorically concluded that alleged “market manipulation” by refiners was not the reason for California’s high gas prices.[25] In addition, a federal court recently rejected a class action lawsuit alleging manipulation of the fuel supply market.[26]

“How do you view the various policy options presented to help mitigate price spike risk? Which do you see as more effective, and why? Are there other options that should be considered?”

It is too soon to opine on the potential effectiveness of the various policy options presented – some of which lack detail or are not readily understood – to mitigate the risks of price spikes. But one recommendation is clear. WSPA urges State policymakers to evaluate ways to incentivize infrastructure investments to maintain a safe, reliable, and affordable California transportation fuels system that will be needed for decades to come. This could be done by modifying policies and regulations that make doing business in California increasingly more difficult – including the permitting process, the Low Carbon Fuel Standard (LCFS), and the Cap-and-Trade program – and instead encourage and expedite projects needed to produce, refine and deliver to market the fuels Californians demand while reducing emissions. Currently, some California policymakers are sending a clear signal that refiners are simply not wanted in the world’s third largest fuels market – even as Californians continue to rely heavily on the products, fuels expertise, and extensive infrastructure that the petroleum industry provides. We encourage the CEC to reject this invitation to remake California’s fuels market into a more emissive, more carbon intensive, and less reliable import-only market.

Below are more detailed responses, where applicable, to the short- and long-term policy options presented at the workshop. We would appreciate the opportunity to work with CEC staff to better assess the policy options being considered prior to presentation of the draft Transportation Fuels Assessment report.

Potential Short-term Policy Options

- *RVP specifications* – This could be done, when conditions warrant, as has been done in the recent past; while this will not prevent or “fix” all market volatility – and it does come with an emissions impact – the early change could be helpful to alleviate short gasoline supply challenges. When the State sees “risk” to supply in heavy shutdown periods that coincide with low Petroleum Administration for Defense Districts (PADD) inventory levels, policymakers could look to partner with refiners to look for potential temporary regulatory waivers or RVP waivers when applicable.
    - If this is intended to mean some type of cost pressure relief valve, to allow Federal Reformulated Gasoline or conventional gasoline to be sold (presumably with an

[24] California Energy Commission, *What Drives California’s Gasoline Prices* (September 2022), https://www.energy.ca.gov/data-reports/energy-insights/what-drives-californias-gasoline-prices#:~:text=Gasoline%20price%20changes%20in%20California,and%20significant%20unplanned%20refinery%20outages
[25] Additional Analysis on Gasoline Prices in California, CEC, October 2019 https://www.energy.ca.gov/sites/default/files/2019-11/Gas_Price_Report.pdf
[26] Persian Gulf Inc., v. BP West Coast Products, et al.

emissions offset mechanism), we encourage the CEC to examine how these gasoline supplies could be quickly delivered to the isolated California market and what challenges may be presented by introducing non-CARB compliant gasoline into the fuels distribution system. The CEC would also need to evaluate how this would affect the integrity of the CARBOB gasoline system.

- *Insurance policies for imports* – WSPA is unclear what this policy option means.
    - If this is intended to mean that importers of gasoline and blending components (e.g., alkylate) would be provided a guaranteed landed price weeks after they depart Asia to remove any potential risk of spot gasoline prices collapsing by the time the cargo arrives, this would presumably incur a significant cost for the State.
    - Further, this concept could result in importers sending cargoes whenever the local spot prices were sufficiently high enough to cover their costs, resulting in even more imports that would potentially create an oversupply of gasoline.
    - The State would also have to ensure that there would be marine infrastructure and on-shore tankage sufficient to handle the influx; WSPA questions the feasibility and availability of such import capacity given existing conditions and forthcoming regulations, including the recently adopted At-Berth Regulation, which currently does not provide a viable long-term compliance path for tanker vessels calling on California ports and terminals.
    - This concept may not prevent market volatility from occurring.
    - If this proposal is intended to mean that the State would "forward purchase" gasoline to reduce import risks, a concept that had previously been presented in August 2016 to the Petroleum Market Advisory Committee,[27] the CEC would need to re-evaluate how this gasoline would be sourced, transported, and delivered. This concept had also been studied for the CEC in April 2003 and found that it would be "unlikely to transform the market" and, "[y]et more problematic, all the state's procedures for procurement and inventory control exemplify the rigidity opposite to the flexibility needed for sophisticated trading in forward markets."[28]
    - U.C. Davis academics Jeffrey Williams and Jennifer Thompson previously studied price spikes and California's forward market for the CEC, concluding that "the forward market for wholesale gasoline in California proves to be sufficiently sensible to attract imports during local refinery outages. California prices spike principally because of the time needed to ship California-grade gasoline, about one month, which, not coincidentally, is the time frame in the forward market." The study revealed that "no quick fix is possible because the state itself cannot provide a fix, and more fundamentally, because the forward market is not broken...Our study of gasoline forward markets further revealed a false premise behind this concern over price spikes. Many point to periods when the price of gasoline was much higher in California than elsewhere, much higher than the known costs of transportation, and imagined that such violations of arbitrage indicate a failure on the part of the marketing system. The comparison of spot spatial prices rests on the false premise that gasoline can move from far away to California within a day. The forward market's prices, which allow for the necessary time for shipments, have

[27] "Market-based Policy Concepts Overview & Issues" CEC staff presentation to the Petroleum Market Advisory Committee, August 16, 2016.
[28] "Price Spikes and Forward Markets for Gasoline," Jeffrey Williams and Jennifer Thompson, U.C. Davis

accorded with arbitrage: The marketing system has been mitigating prices spikes by attracting imports into California."[29]

- *Export coordination* – WSPA is also unclear what this policy option means.
  - If the CEC is implying an option to cease deliveries to Nevada and Arizona in response to market volatility, it should be noted that gasoline exported to those states is not the same quality as California's Reformulated Gasoline. Because the California refineries cannot feasibly make 100% CARB gasoline, any non-CARB gasoline would have to be exported, or refiners would have to reduce crude oil processing – which would also reduce jet and diesel supplies as well. California refiners produce enough CARB gasoline to meet their contractual commitments (local demand) and produce the less capital-intensive products for Arizona and Nevada. Even in times of market volatility, gasoline would still need to be imported to Arizona and Nevada and would still likely have to come through a California port and then be transported through the same pipelines. The State should also examine whether a policy requiring gasoline to be preferentially delivered in California rather than in other states would violate the Interstate Commerce Clause of the U.S. Constitution, and what harms would occur in our neighboring states (including increasing fuel costs).
  - Feedstocks are purchased based on forecasted demands. If these export outlets are closed off, the feedstocks are not procured and there is no quick handle to help in the event of market volatility (e.g., backing exports into the local market quickly by sourcing them from other out-of-State producers). There are also "demand constraints" on industry producing more gasoline – like limitations on the ability to manage oil outside California's jurisdiction. If industry does not have an outlet, this could result in constraints for the oil within California's demand.
  - Private industry is incentivized to be efficient and to minimize potential air emission sources. This results in little capacity to produce or maintain excess fuel supplies. Because of California's administrative processes and approvals to obtain a permit and build a tank, export outlets are critical to help manage the refineries reliability as demands change for fuel.

- *Short-term demand-side management* – WSPA does not believe "flex alerts" would work as intended in the fuels market, versus how they have worked in the electricity sector (i.e., temporary voluntary reductions in consumer demand to ease strain on the electric grid during periods of anticipated electricity shortage). From past real-world experience,[30] we know that consumers' belief that a fuel shortage is coming (even when incorrect) often results in "panic buying" – both to purchase *and store* gasoline – only exacerbating a problem this policy option intends to solve while potentially creating or furthering supply/demand imbalances in an already tight fuels market.
  - The concept of "transit support" is also unclear and potentially could be very expensive. It also would not prevent a price spike.
  - Reducing Vehicle Miles Travelled (VMT) and increasing ZEV penetration, while certainly longer-term policies being pursued by other State agencies, will likely do little to prevent short-term acute periods of market volatility. In considering such policy options, WSPA encourages the CEC to evaluate associated cost shifts; reducing VMTs by shifting

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[29] "Price Spikes and Forward Markets for Gasoline," by Jeffrey Williams and Jennifer Thompson, U.C. Davis Giannini Foundation of Agricultural Economics, CEC Publication Number 2003-04-21_600-03-007D
[30] https://www.npr.org/2021/05/11/996044288/panic-drives-gas-shortages-after-colonial-pipeline-ransomware-attack

consumers from internal combustion engine vehicles to public transit is a policy the State already pursues but that necessitates the mass availability of affordable and safe transit options that conveniently meet consumer expectations. Despite the aggressive VMT reduction targets in the 2022 Scoping Plan Update, CARB's most recent SB 150 (2017) Progress Report has clearly indicated that VMT in California is not declining.[31] Reducing VMT is by no means a practical short-term measure on fuel demand management, due to the various planning and infrastructure challenges identified by the SB 150 Report. Dramatically increasing the fleet of new ZEVs on California roadways necessitates a prohibitively massive investment by the State to rapidly incentivize and deploy affordable ZEV options, and to conduct an extensive buildout of new charging/refueling infrastructure statewide – all while also maintaining affordable electric rates. Even CARB has acknowledged that the State does not currently have the electric generation capacity to supply a massive influx of ZEVs, and will need significant buildout and upgrade of California's statewide electrical generation, transmission and distribution infrastructure over the next decade to meet such electricity demand. Moreover, the State already struggles with some of the highest electricity prices in the nation. According to the most recent July 2023 data[32] from the U.S. Bureau of Labor Statistics, Los Angeles households paid 65.7% more for electricity (28 cents per kilowatt hour (kWh)) than the nationwide average (16.9 cents/kWh). For the past five years, Los Angeles area consumers paid 36.5% more for electricity than the U.S. average in the month of July. In the Bay Area, households paid 106.5% more for electricity (34.9 cents/kWh) than the national average – and 58.6% more for electricity in the past five years than the national average for the month of July.[33] A widespread shift to electric vehicles, as envisioned by California's policy leaders, would simultaneously require the delivery of a significant amount of new affordable and reliable electricity service – something California clearly lacks the capacity to do today. Indeed, the California State Auditor recently reported that California's electricity rates have increased by more than 50% during the last seven years according to data from the California Public Utilities Commission.[34]

- *Temporary pause on taxes and fees*
  - WSPA encourages the State to consider how potential amendments to the Cap-and-Trade program and LCFS regulations to dramatically *increase* their stringency may impact gasoline costs in California. WSPA is concerned that proposed amendments to both policies could further compromise the supply reliability and affordability of critical transportation fuels.
  - Temporarily waiving taxes and/or fees may reduce consumer costs but is not likely to reduce consumer demand, which remains highly price-inelastic in California. It also does nothing to alleviate periods of limited fuel supply, nor does it serve to provide the funding necessary to pay for roadway maintenance and improvements. Fiscal policy should include fair and equitable policies that do not disadvantage specific industries or categories of taxpayers.

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[31] CARB (2023). 2022 Progress Report on California's Sustainable Communities and Climate Protection Act. Available at: https://ww2.arb.ca.gov/sites/default/files/2023-05/2022-SB150-MainReport-FINAL-ADA.pdf. Accessed: August 2023.
[32] https://www.bls.gov/regions/west/news-release/averageenergyprices_losangeles.htm
[33] https://www.bls.gov/regions/west/news-release/averageenergyprices_sanfrancisco.htm
[34] "Electricity and Natural Gas Rates: The California Public Utilities Commission and Cal Advocates Can Better Ensure That Rate Increases are Necessary," August 2023 http://auditor.ca.gov/pdfs/reports/2022-115.pdf

- Conversely, a new penalty/tax on margins would only reduce the potential capital available to California refineries over time and make it more difficult to recover significant capital expenditures in a reasonable amount of time to make the investment worthwhile. Less investment may impact the ability to produce quality fuels over time, which could further exacerbate existing supply challenges. WSPA further urges the CEC to consider the market implications (including to supply) for a publicly-traded company to knowingly violate a State-imposed margin cap.

Potential Long-term Policy Options

- *State-run storage* – The industry currently operates an extensive storage system; WSPA recognizes that the State would likely face several challenges with implementing and utilizing any State-run storage system in an effort to address complex inventory scenarios. The CEC previously evaluated the feasibility of this concept in 2003 and determined that State leaders should ***not*** proceed with a Strategic Fuel Reserve concept due to several unintended consequences that "could limit its effectiveness as a tool to moderate gasoline price spikes and could reduce the total supply of gasoline in the state" (e.g., displace private inventories, thereby transferring much of the costs of maintaining private inventories to the State without significantly dampening price volatility).[35]
    - The CEC separately focused its attention on the complexity of the tank permitting process. A consultant's report noted, "The possible concerns range from overly complex regulations, to open-ended time frames, to overlapping jurisdictions, and to barriers raised by citizens (known as NIMBY). All of this translates into additional costs that ultimately get passed on to the consumer."[36] That report concluded that, "The permitting process in California is in general detailed and complex. The permitting process for petroleum product storage facilities is particularly challenging for permit applicants and permit writers. The potential benefits of streamlining the permitting process for petroleum product storage facilities include an increase in petroleum storage capacity, which would improve fuel supply reliability throughout the State." They made numerous recommendations, including: additional training and technical assistance services (including for the California Environmental Quality Act), timelines and milestones, independent reviews, and inter- and intra-agency coordination.
    - California would also need to assume pricing risks (just as the Federal government does for the U.S. Strategic Petroleum Reserve); decisions would need to be made of when to buy and when to sell. The challenges will remain in obtaining permits for tanks and maintaining product quality, emission factors, and product stability over time (as fuel cannot simply be left in tanks for years).
    - How California would establish such a program and how it could potentially reduce private storage are key issues that would also need to be reexamined before rendering judgment on whether this could help limit the height and duration of price spikes. Such a program may only have a temporary effect, especially if it serves to reduce or eliminate private storage.
    - If this proposal is intended to mean minimum inventory levels, whereby the State would require each seller to hold a certain amount of inventory, WSPA would be concerned that this could reduce the amount of gasoline available to market participants to address periodic supply imbalances. Minimum inventory levels may also have major drawbacks.

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[35] "Feasibility of a Strategic Fuel Reserve in California," Commission Report, CEC July 2003 P600-03-013CR
[36] "Permit Streamlining for Petroleum Product Storage," Draft Consultation Report, April 2003 P600-03-006D

As the CEC previously identified,[37] limiting the draw-down level for current in-service storage tanks will decrease working storage capacity, impeding the operational capability of refiners and marketers. It may also reduce strategic inventories by traders and non-refiners – a consequence of which should be evaluated by the CEC. Minimum inventory holdings may warrant the construction of new storage tanks, though doing so is already a difficult regulatory endeavor. Further, since reformulated gasoline tends to be more difficult to inventory, firms will tend to avoid inventories of it and could obfuscate the market from running storage efficiently. This may actually serve to increase market volatility. In addition, "Boutique fuels increase the problem of storage by eliminating pooling. By proliferating fuel types, the amount of storage needed to prevent significant price spikes rises. Storage works like insurance: it reduces costs to be large. By dividing the nation into many smaller, separate fuel types, we increase the costs of storage and reduce its effectiveness."[38] It would likely also not prevent market volatility.

- *Increase ethanol blend requirement* – WSPA understands that CARB is still in the process of reviewing the required multimedia analysis. Amongst the factors to consider with this potential option are that:
  - While this proposed policy option could enable an expanded supply of lower-carbon gasoline provided any issues with a "blend wall" can be addressed; once available, it would not prevent market volatility.
  - Ethanol blending supports market-based mechanisms that promote lowering the carbon intensity (CI) of fuels. Feedstock availability is critical to growing the supply of lower-CI biofuels and policies should support the co-processing of traditional and biofeedstocks; any artificial constraint – such as instituting an arbitrary cap on biofuel-based feedstocks in the LCFS program – would also limit ethanol blending in addition to constraining the supply of products like renewable diesel.
  - Increased ethanol blending requirements could also result in compatibility issues at retail sites, such as for piping connections, which should be considered.

- *Regional blends* – WSPA is not sure if this means requiring the sale of CARB reformulated gasoline in Arizona and Nevada, or something entirely different. The different fuel specifications in Arizona and Nevada likely do not create market volatility, as the gasoline delivered here is not the same California reformulated blend sold in California. In any event, we see no evidence that Arizona and Nevada consumers would agree to pay much more for a different gasoline specification that is otherwise not required for air quality compliance in those states, or that those states would allow such a strategy in the first place.

- *Non CARBOB blends* – WSPA is also not sure what this means. If it means that non-CARBOB gasoline should be allowed to be imported into California during market volatility, it fails to address the insufficient capacity in the Pacific Northwest to surge imports into California in the initial days of a market disruption. Further, there is no spare barge or Jones Act vessel capable of moving large quantities of incremental barrels that were not previously planned as part of another supply obligation. This proposed option would likely not prevent or significantly mitigate market volatility. If it implies that non-CARBOB blends would be allowed, WSPA is concerned with how this could impact the integrity of California's gasoline

[37] "Market-based Policy Concepts Overview & Issues" staff presentation to Petroleum Market Advisory Committee, August 16, 2016

[38] Congressional testimony of R. Preston McAfee, May 2, 2002.

system; preventing contamination of tanks, valves and pipelines could be both costly and time consuming.

- *Large-scale shift to a public utility model* – If this potentially means California would take over in-State refineries, this would almost certainly constitute a substantial taking requiring just compensation.
    - Electric and natural gas utilities are natural monopolies that compel a single operator to avoid the deployment of multiple transmission and distribution systems into a single home or business. The transportation fuel market is not a natural monopoly as it allows for separately operated product distribution systems.
    - This would be anti-competitive and signal the State's deliberate acceptance of market monopolies. This is not allowed under existing State statutes and has been proposed (and failed) in the past.
    - California taxpayers may not be amenable to purchasing refineries and taking on all associated liability.
    - Perhaps most significantly, even this radical step would likely not prevent market volatility. A State monopoly on petroleum refining and supply would not address the supply and infrastructure challenges inherent to the California system, nor would it prevent unplanned equipment failures that lead to temporary supply disruptions, nor would it address continued demand by California consumers for petroleum fuel supply for the decades to come. It should also be noted that price controls implemented in other regions have failed to provide lower costs and needed energy investments.[39]
    - Additionally, California's insurance market may provide a cautionary tale regarding price controls. California law requires insurers to have their proposed rates approved by the Insurance Commissioner before they can charge policyholders. Because of rising costs, insurers have applied to charge substantially higher rates and have generally been denied. As a result, some larger insurers recently stated that they would stop insuring new policyholders in California. A cost-controlled model could similarly challenge the viability of the gasoline-refining industry in the State.

- *More imports* – if this potentially means adding more marine terminals, WSPA questions whether this would be achievable given known regulatory constraints and anticipated local opposition. As discussed above, CARB's recent At-Berth Regulation still provides no permanent path to compliance for petroleum tankers, and only incentivizes fewer port visits, not more.
    - If this potentially means more rail shipments, we question whether there is sufficient rail capacity and availability to absorb the additional supplies into California. The CEC's 2009 IEPR recognized the constraints additional imports would place on California's transportation fuels system: "Reliance on foreign oil imports increasingly puts the state's fuel supply at risk, not only because of security and reliability concerns, but also because the marine ports are not expanding to meet expected growth in demand...The Energy Commission forecasts that crude oil imports will continue to increase, requiring expansion of the existing crude oil import infrastructure. This infrastructure is critical in ensuring a continued supply of feedstocks to enable refiners to operate their facilities and maintain a reliable supply of fuel for California and neighboring states." The report continued by focusing on Southern California constraints, noting "To add further strain,

[39] https://www.nbcnews.com/id/wbna12690142

especially in Southern California, staff expects the increased imports of crude oil to result in a greater number of marine vessels arriving in California ports, with 46 to 272 additional arrivals per year by 2030. Additional storage tank capacity beyond that already identified as part of the Berth 408 project must be constructed to handle the incremental imports, and it is unclear where these can be located given the competition for land in and around the ports."

- Whether we are describing imports from other states or overseas – or crude oil, intermediates or finished gasoline components – California would need significant upgrades to infrastructure and outlet logistics to manage the flexibility. This includes increasing options for exports, more pipelines, and adding storage capacity. Pipeline infrastructure is already at-risk given the known permitting, investment, and construction challenges.
- As it works on the SB X1-2 Transportation Fuels Transition Plan, we urge the CEC to consider these infrastructure limitations and how the introduction of renewables places strain on the California supply chain. This supply chain has had decades to optimize the supply of fossil fuels and is now being expected to react at record pace to facilitate the introduction of renewables. Moving too quickly without the infrastructure to support new fuel products, or lacking a reliable supply of existing fuel products, could leave California at risk of more frequent transportation fuel supply shortages.
- *Export pipeline modifications* – WSPA is also unsure what this means. If it means reversing the flow of pipelines to Arizona and Nevada, this would be infeasible.
- *Rail* – If this is intended to capture the development of rail transloading sites in California by the State to enable shorter duration resupply options to refiners and marketers, it may enable market volatility to be alleviated more rapidly compared to resupply from foreign sources via marine vessels. This would also be beneficial to the State for emergency planning purposes in the aftermath of a catastrophic event (e.g., an earthquake that shuts down in-State refining capacity in either Northern or Southern California). However, rail transport would likely require a vapor disruption unit to be able to move the product from one tank to another, which would be quite laborious and resource intensive.
- *Jones Act* – If this concept is suggesting an elimination of the Jones Act, then domestic marine movement costs could be reduced. However, the federal Jones Act is not the cause of California gasoline costs, nor is it within the State's jurisdiction to repeal or amend.
- *Some State-managed imports* – If this concept infers that the Department of General Services starts purchasing fuel from foreign producers to sell to California consumers, WSPA urges that the State consider where that fuel could be off-loaded, into whose storage tanks, and how the fuel would get to retail locations. Again, regardless of whether some fuel imports are managed by the State, we would not expect this step to have any effect on the ongoing fuel supply infrastructure issues discussed above.

Other Policy Options That Should Be Considered

Permit streamlining – Additional transfer, storage and related infrastructure would be needed to accommodate the anticipated growth of imported fuel supplies – particularly if California continues to disincentivize and/or artificially constrain in-State production and refining – as a replacement resource. This would include modifications to, and additions of, marine terminal infrastructure and, potentially, rail infrastructure (for additional renewable fuels and associated feedstocks) for gasoline and jet fuel. We would suggest that the CEC consider supporting streamlining and/or consolidation of the permit processes needed to get the necessary fuel supply infrastructure in place.

The 2005 IEPR called for "improving and expanding petroleum infrastructure to meet California's needs in the next 20 years." It found that "regulatory and permitting coordination among a potpourri of local, state, and federal agencies presented a barrier to infrastructure expansion" and recommended "initiating an effort to identify and develop permitting guidelines for petroleum infrastructure projects, with no reduction in environmental standards." The 2005 IEPR further recognized that regulatory challenges at the State, regional, and local government levels delayed permitting of transportation fuel facilities. However, "[m]ost of the problems can be addressed by 1) clearly and accurately defining the issues and 2) balancing competing interests when designing/maintaining environmentally and technologically robust and safe infrastructure. There is industry and agency acknowledgement that better coordination and information transfer will facilitate permitting."

There is industry and agency acknowledgement that better coordination and information transfer will facilitate permitting. Amongst the recommendations to address permitting challenges from the 2005 IEPR were: 1) identifying key responsible trustee, and cooperating agencies; 2) providing timely CEQA/NEPA documentation consultations and comments to facilitate lead agency decision-making that may expedite the issuance of permits; 3) partnering by agencies and private actors during preparation of environmental documents and project permitting processes; 4) coordinating agency review of projects and/or environmental documents to avoid duplication of effort and expedite decisions; 5) establishing an interagency workgroup group to inform agency staff on the policy implications of particular projects or activities; 6) establishing, coordinating, and adhering to project timelines and milestones; 7) considering expedited agency reviews or permit applications when appropriate and feasible; 8) considering approval and use of master plans, rather than per-improvement requirements; 9) ensuring adequately trained staff (including those trained with energy facility siting experience); 10) clearly identifying a "chain of command;" and 11) creating and using clear criteria for regulatory decisions, amongst others.

Incentives for use of California-produced crude – California policies that push for setbacks and other crude producing restrictions will limit options for local crude and result in the same adverse impacts associated with increased importation of foreign crude and/or refined products. For this reason, we would also recommend that the CEC consider supporting incentives for local crude production here in California. Local production would not only avoid the emissions associated with transport of oil and finished products, but would also continue to support good paying blue-collar jobs in the State.

In conclusion, any proposed intervention that entails an increased regulatory burden on refiners, importers, or other market participants will likely raise barriers to local production and refining here in California, disincentivize investment in needed additional supply infrastructure, discourage additional production and long-term commitment to the California markets, increase reliance on foreign imports and the greater emissions they would cause, fail to address Californians' continuing demand for refined petroleum products over the next several decades, and only worsen the existing negative constraints on transportation fuel supply that will ultimately drive gasoline prices *up*, not down. This has historically been true for the LCFS and gasoline taxes, and it would certainly be the case for any proposed penalty on gasoline margins.

The CEC should partner with the industry to reduce regulatory barriers that keep gasoline prices high and exacerbate natural factors that cause price spikes.

"Have other costs been particularly problematic for stable prices for retailers or producers of fuels?"

First, it is important to note that transportation fuel prices are never "stable" in an openly competitive market. Prices in the California transportation fuels market are influenced by a multitude of global factors beyond the control or influence of any one business, industry, State agency or governmental body. These factors include the global prices of crude oil, levels of crude oil exploration and extraction, international shipping rates, the availability of international fuel supply for importation to California, the number and intensity of competing buyers for the same crude oil supplies and/or refined products, available refining and storage capacity in different regions, global demand for passenger and light/heavy-duty vehicles, the costs of refining or importing fuels meeting the California reformulated gasoline standards, pipeline capacity, weather impacts, and foreign events/conflicts that disrupt commodity supply. Similarly, transportation fuel costs are never "stable" due to numerous local and regional factors, including the availability and prices of marine/rail and pipeline transport, costs of meeting applicable regulatory requirements, applicable taxes and fees, costs and availability of labor, the capacity and durability of fuel supply infrastructure, the degree of isolation of a market from out-of-State markets and their capacity to quickly resupply during local supply disruptions, and individual pricing decisions made by thousands of wholesalers and retailers on a day-to-day basis.

Wholesale fuel cost escalation typically occurs in the aftermath of significant unplanned outages, a reflection of increased supply scarcity, providing a necessary incentive to attract incremental supplies of costlier imports to enable the alleviation of any temporary supply tightness. If fuel prices were set to fixed or artificially capped levels, fuel providers outside the State may have little or no incentive to periodically send transportation fuel to California to take advantage of favorable market prices. Under the free market model, supply and demand result in encouraging investments for more supply and/or reduce demand by lowering consumption. California must recognize that, if policies are implemented to simply eliminate fossil fuels in the State as quickly as possible, *investments are thereby discouraged at all levels of the conventional fuels supply chain.* We are already seeing these policies implemented by multiple local jurisdictions across California that are adopting local ordinances[40,41,42,43,44,45,46] or moratoriums,[47] or considering similar motions,[48] prohibiting the development of new gas stations. Such measures likely only serve to force investment out of the State, thereby artificially reducing competition.

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[40] https://petaluma.granicus.com/MetaViewer.php?view_id=31&clip_id=3218&meta_id=483708
[41] https://napavalleyregister.com/community/calistogan/news/city-of-calistoga-approves-gas-station-ban/article_105c83fd-3b37-51b0-a886-06248936a3d0.html#tncms-source=signup
[42] https://legistarweb-production.s3.amazonaws.com/uploads/attachment/pdf/1292848/6L_Ordinance_Gas_Ban.pdf
[43] https://www.jurupavalley.org/AgendaCenter/ViewFile/Agenda/_08032022-520
[44] http://santa-rosa.legistar.com/gateway.aspx?M=F&ID=c127403c-d5c1-428d-9d38-04b715fff38a.docx
[45] https://legistarweb-production.s3.amazonaws.com/uploads/attachment/pdf/1619091/ord731_Gas_Station_Prohibition.pdf
[46] https://www.marinij.com/2022/11/22/fairfax-bans-new-and-expanded-gas-stations/
[47] https://www.cityofamericancanyon.org/home/showpublisheddocument?id=18832
[48] https://clkrep.lacity.org/onlinedocs/2021/21-0533_mot_05-18-21.pdf

In addition, other costs have increased too. In July 2023, consumers paid 27.2% more for natural gas in the Los Angeles area[49] and 29.7% more in the Bay Area[50] than the national average. The industry has been impacted by a multitude of costs to operate a refinery, supply racks, and stations with long lead times for materials, higher employee costs, higher constructions costs, etc. With the Consumer Price Index for the West consistently experiencing double digit differences between the average for U.S. cities, these costs impact all manufacturing as well as refiners.[51]

"Are refineries expecting any new or exacerbated distribution bottlenecks for logistics outside the refinery gates?"

- Shipping constraints at marine terminals, through the Panama Canal, and the general availability (or unavailability) of specialized ships create logistical bottlenecks as described above. Freight costs have also skyrocketed, creating another barrier for imports (and resulting in high costs on the West Coast for gasoline shipped in from overseas).
- Also, as discussed above, CARB's recent amendments to its At-Berth Regulation provide no permanent compliance path for petroleum tankers in California due to its requirement that tankers install emissions control equipment not yet demonstrated in practice for tankers. As such, many petroleum tankers may be forced to limit their visits to California ports and terminals in an attempt to comply with the amended Regulation as soon as 2025. We are concerned that, until and unless the Regulation is further amended to provide a clear compliance path for tankers that does not artificially limit vessel visits, it will continue to be a barrier to marine imports of crude oil, refined transportation fuels, and renewable fuels into California.
- Finally, as discussed above, we believe the CEC should consider measures to encourage increased domestic production and refining, as this local and lower-cost product competes more effectively and avoids the increased emissions associated with importing crude oil and/or refined product.

"How do local air pollution district rules influence site operations and how are they interacting with other state programs?"

Local air pollution control regulations can yield marginal emissions reductions at facilities, but can also come with exorbitant cost requirements for impacted refiners, and can disincentivize or even punish increased fuel supply into the market. These regulations can directly influence business decisions regarding potential refinery consolidation or relocation outside California, activities that are both counter to the State's statutory charge to ensure "adequate and affordable fuel supplies for California motorists and businesses."

As noted above, refineries compete for internal capital with other refineries that a company owns throughout the country. When an air regulation mandates a rigorous new emission standard, even if it only produces a very tiny reduction in ambient emissions, the investment required to bring facilities into compliance can range into the hundreds of millions of dollars for that marginal reduction. Companies must make internal decisions on whether such massive investments are economically feasible for their California facilities. Further, if the State expects

[49] https://www.bls.gov/regions/west/news-release/averageenergyprices_losangeles.htm
[50] https://www.bls.gov/regions/west/news-release/averageenergyprices_sanfrancisco.htm
[51] Consumer Price Indexes Pacific Cities and U.S. City Average - July 2023 (bls.gov)

to rely on more marine imports, doing so could be extremely difficult in Southern California if the South Coast Air Quality Management District's Indirect Source Rule is approved at year-end. That rule could potentially limit the import (and export) of goods from the ports of Los Angeles and Long Beach in an effort to address mobile source emissions – despite the fact that all port operations-related emissions sources are currently regulated by international treaties, federal law, State regulations, port policies, tariffs and leases.

Permitting delays at local air districts can have a negative impact for improvement projects, and the associated emission reductions, at various facilities as well. The resulting regulatory uncertainty can lead to reduced investments in critical infrastructure projects, hurting progress on achieving air quality goals. This is a significant issue the State should help address.

Local air district rules also affect in-State production. Kern County's drilling permit program includes the highest air quality mitigation fees for drilling a new well (because mitigation requires zero emissions). The San Joaquin Valley Air Pollution Control District's air quality fees for continuous operations and operational equipment also contribute to one of the highest expenses for companies to comply with. This is in addition to the federal Environmental Protection Agency's Title V permit program requirements.

"Alkylate has been brought up as a primary blending component for gasoline production. Please describe the supply chain for obtaining this material and why has it become more valuable in recent years. Are other blending components similarly situated?"

When refineries have unplanned downtime that impacts octane balances, Alkylate can sometimes facilitate additional blending of components into finished CARB fuels that would otherwise need to be exported (i.e., Alkylate can quickly swell the production of gasoline).

Alkylate is a type of gasoline blending component with more desirable properties (such as low sulfur and high octane) that enable refiners to meet stricter CARB reformulated gasoline standards and produce sufficient volumes of premium gasoline to meet consumer demand. Alkylate has increased in value in recent years due to such factors as: growing demand for premium gasoline to meet increased sales of higher-performance vehicles, implementation of the Tier 3 regulations requiring refiners to reduce gasoline sulfur content that has a tradeoff of lower octane values for some blending components, and inadequate U.S. refining capacity to upgrade lower-octane blending components.

Most California refiners operate alkylation units to meet most of their needs to achieve CARB gasoline standards and produce sufficient volumes of premium gasoline. Alkylate is the predominant type of gasoline blending component imported into the State due to its versatility and availability in southeast Asia and India.

The "supply chain" for obtaining imports of blending components, renewable fuels, and refinery feedstocks usually involves marine movements, except for ethanol imports via rail tank car. Consequently, this type of chain is vulnerable to: shipping availability and rates, international competition for more desirable components (such as alkylate), and impediments to California marine infrastructure lease renewals and local opposition for industry attempts to expand said infrastructure to meet changing market needs.

SUMMARY

The comments described above are certainly not an exhaustive list of every issue WSPA members have relating to the SB X1-2 Transportation Fuels Assessment Workshop, or regarding the implementation of SB X1-2 generally. WSPA reserves its right to supplement these comments as additional or different issues arise in the course of implementing SB X1-2 and in the CEC's further consideration of whether a refining margin cap would benefit California consumers or the California transportation fuels market. We would also reserve the right to submit additional comments in the context of any formal rulemaking process CEC decides to conduct as part of its consideration, and we would continue to strongly encourage a formal rulemaking for the benefit of CEC, the stakeholder, and California consumers.

We would like to work with the State to identify ways to encourage investment in state-of-the-art lower carbon crude oil production, enhance in-State refinery capacity and critical supply infrastructure, eliminate unnecessary burdens on businesses and, most importantly, create a foundation of mutual respect and collaboration that allows us to work together to help all Californians figure out what needs to be done to ensure that this critically important and complex transportation fuels system works for every Californian.

Thank you for considering our comments. We look forward to working with the CEC to provide ongoing input. Please do not hesitate to contact me at (916) 835-0450 or creheis@wspa.org with any questions, or Tanya DeRivi on my staff, who can be reached at (916) 325-3088 or at tderivi@wspa.org.

Sincerely,

Catherine H. Reheis-Boyd
President and CEO

cc: The Honorable David Hochschild, California Energy Commission, Chair
The Honorable Siva Gunda, California Energy Commission, Vice Chair
Drew Bohan, California Energy Commission, Executive Director
Shant Apekian, WSPA

SOLOMON

California Refiners’ Cost and Margin Analysis, 2000–2022

Western States Petroleum Association

April 25, 2023

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Key Takeaways

- California (CA) Refiners have faced growing operating cost pressures since 2000
  - Personnel, maintenance, and materials costs have increased by 0.5 → 2x
- CA Refiners' margins – gross and net – have **eroded** since 2000 due to crude price and increased operating cost pressures
  - Crude market pricing impacts both refining margins and, depending on market dynamics, "pump prices" for consumers
- Crude is a global commodity and replacing CA crudes increases costs

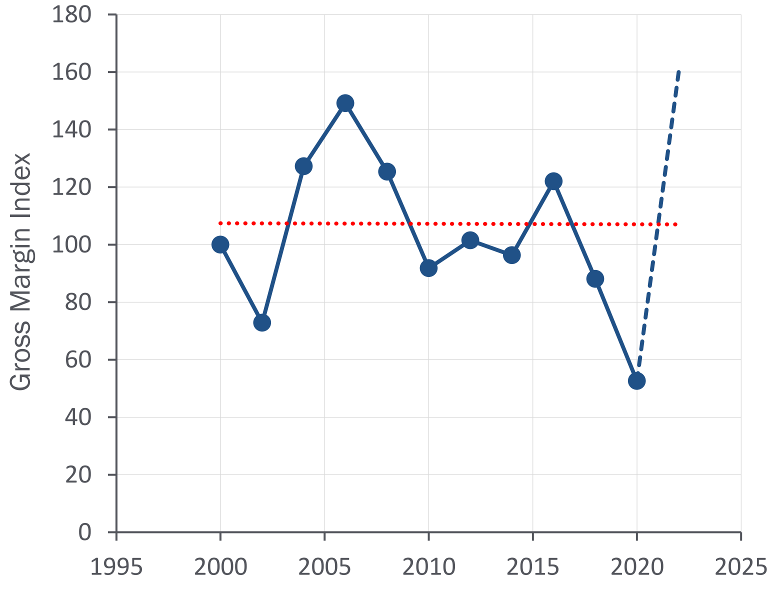
About the Data

- Represents a composite of California refinery data from participants in the Solomon's Fuels Studies*
- "Indexed" data = Composite Actuals in the study year divided by the Composite Actuals in 2000
- "Adjusted for Inflation" = Composite Actuals in each respective study year expressed in 2000 dollars using the US CPI data from:
  - https://www.usinflationcalculator.com/inflation/consumer-price-index-and-annual-percent-changes-from-1913-to-2008/
- Costs for blending ethanol and renewable diesel are not included as most of this blending is done outside the refinery gate
- The cost paid for raw materials includes delivery cost to the refinery
- The value received for products is determined as the products leave the refinery

*Worldwide Fuels Refinery Performance Analysis (Fuels Study)

CA Refiners' Gross Margin

Value of All Products Less Cost of Raw Materials

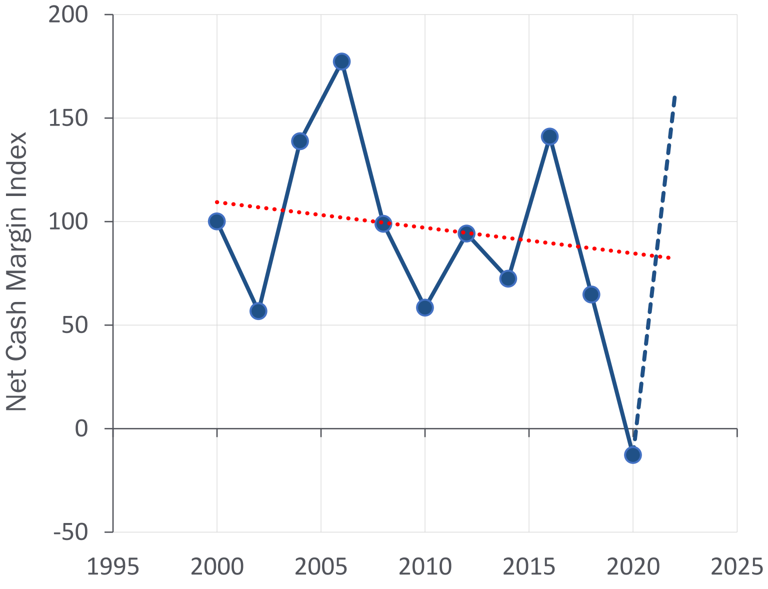


- CA Refiners' Gross Margin trend (red dashed line) is flat from 2000 → 2022
- Benefits in "up years" have been offset in the '10s by lower margins in subsequent years
- Some of the reasons "why" are described in the following slides

Gross Margin Index = Gross Margin in Year/Gross Margin in 2000, adjusted for inflation
Blue Dashed line indicates preliminary 2022 value

CA Refiners’ Net Margin

Revenue Less Raw Materials’ Costs and Total Operating Expense

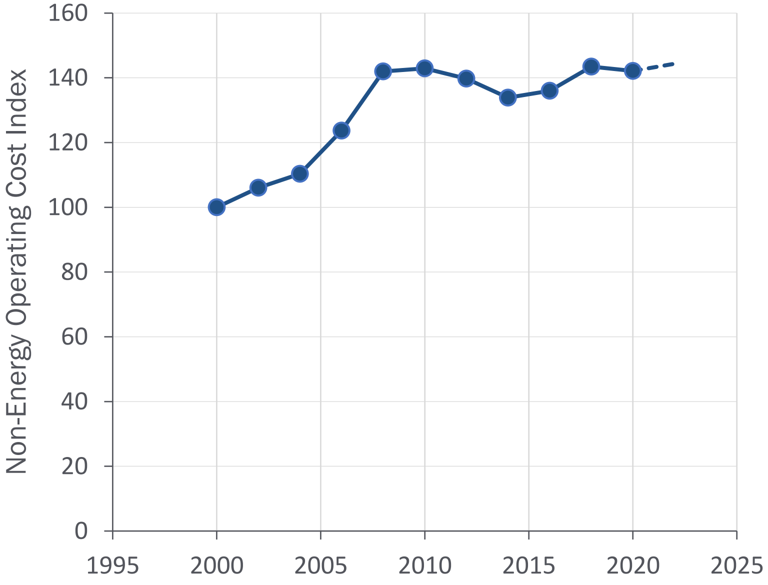


- CA Refiners’ Net Margin trend (red dashed line) has declined from 2000 → 2022
- In 7 of 12 studies since 2000, Net Margin was less than 2000’s Net Margin
- Net Margin was negative in 2020, before rebounding in 2022

Net Margin = NCM Index – NCM in Year/NCM in 2000, adjusted for inflation
Blue Dashed line indicates preliminary 2022 value

CA Refiners' Non-Energy Operating Costs

Total Operating Costs, Excluding Energy

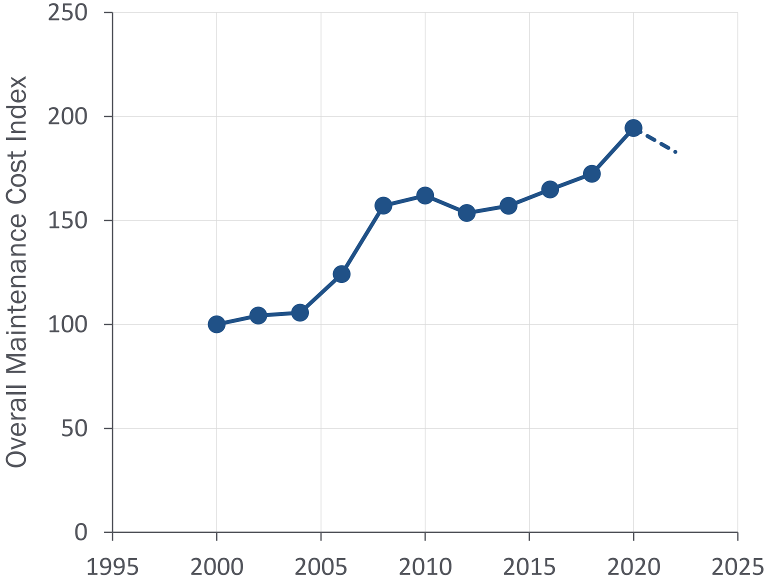


- Even after eliminating inflation, CA Refiners' Non-Energy Operating Costs have increased more than 40% since 2000
- Main cost elements include personnel, maintenance, taxes, chemicals and catalyst

Non-Energy Operating Cost Index = Non-Energy Operating Cost in Year/Non-Energy Operating Cost in 2000, adjusted for inflation
Blue Dashed line indicates preliminary 2022 value

CA Refiners' Maintenance Costs

Maintenance Costs, Personnel and Materials

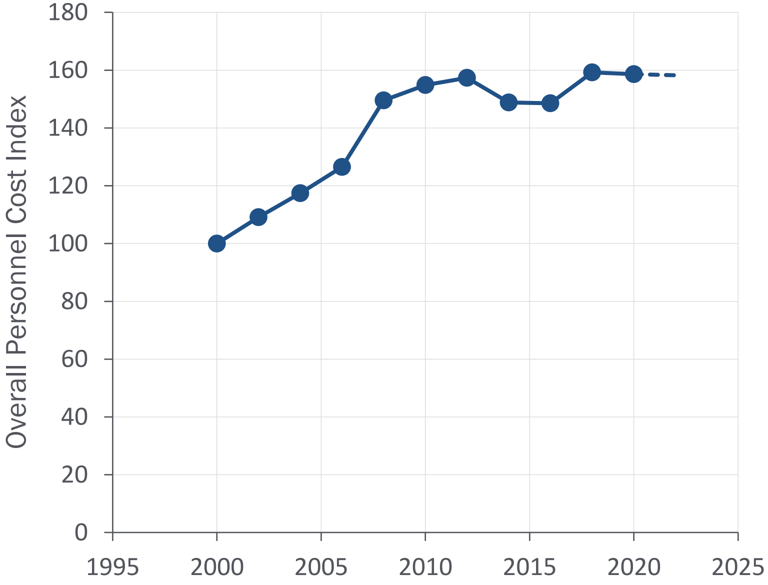


- Maintenance costs are a subset of the prior-slide's Non-Energy Operating Cost
- Even after eliminating inflation, Refinery maintenance costs have nearly doubled since 2000
- This cost includes the personnel and materials needed to inspect, repair, and replace equipment

Overall Maintenance Cost Index = Annualized Maintenance Costs in Year/Annualized Maintenance Cost in 2000, adjusted for inflation
Blue Dashed line indicates preliminary 2022 value

CA Refiners' Personnel Costs

Total Personnel Costs

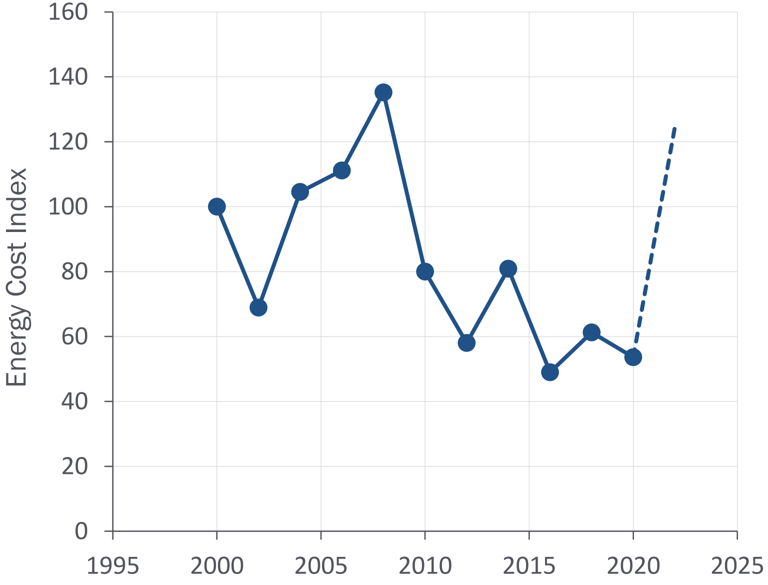


- Personnel costs are also a subset of Non-Energy Operating Cost
- Even after eliminating inflation, refinery personnel costs have increased by ~60% since 2000
- This cost includes company and contract personnel costs

Overall Personnel Cost Index = Personnel Cost in Year/Personnel Cost in 2000, adjusted for inflation
Blue Dashed line indicates preliminary 2022 value

CA Refiners’ Energy Costs

Natural Gas and Electricity Needed to Operate Refineries

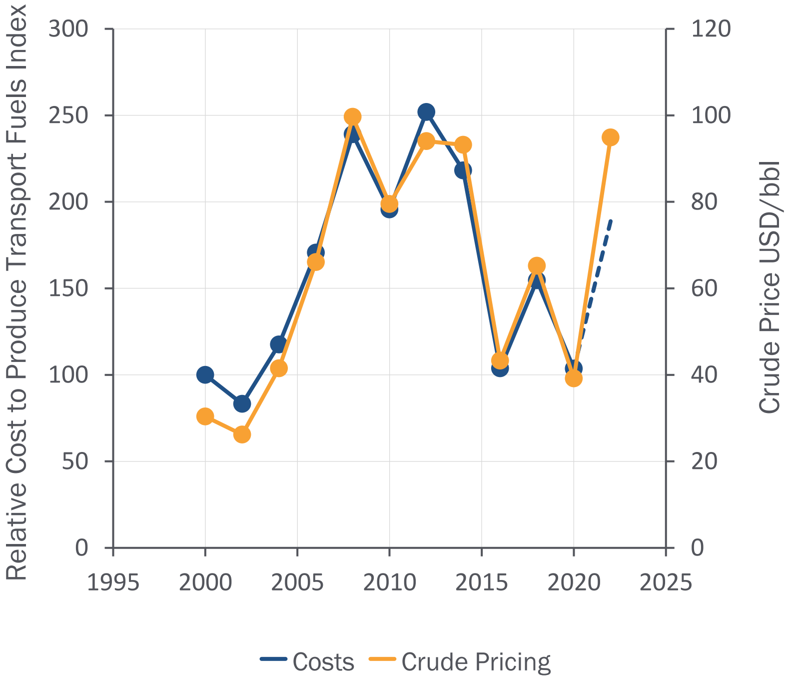


- With inflation’s impacts excluded, energy costs are the one category of refinery operating expense that has not increased since 2000
- Refiners’ have invested to improve energy efficiency
- This investment helped offset a portion of the non-energy cost increases

Energy Cost Index – Total Energy Costs in Year/Total Energy Cost in 2000, adjusted for inflation
Blue Dashed line indicates preliminary 2022 value

CA Refiners’ Costs to Produce Transportation Fuels (Costs)

Costs to Produce Gasoline, Jet & Diesel

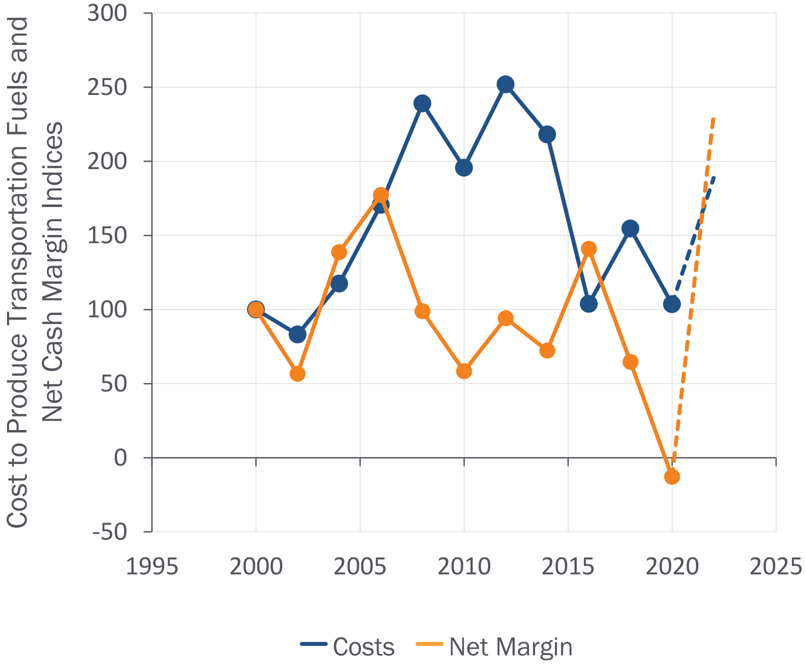


- Both crude pricing and operating costs impact a refiners’ Costs
- This chart compares crude pricing to refiners’ Costs, with inflation’s impacts excluded
- Changes to refiners’ Costs track closely with the industry standard crude pricing

Relative Cost to Produce Transport Fuels Index = Cost to Produce Transport Fuels in year/Cost to Product Transport Fuels in 2000, adjusted for inflation
USD/bbl (United States dollars per barrel)
Crude = West Texas Intermediate
Blue Dashed line indicates preliminary 2022 value

CA Refiners' Inability to Recoup Increases in Costs

Net Margins vs Costs to Produce Transportation Fuels (Costs)

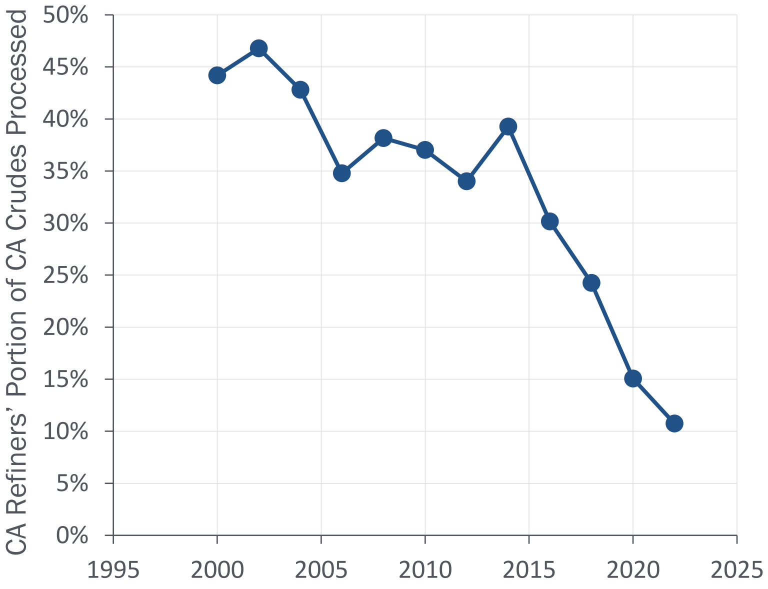


- Refiners are often unable to recoup the increases in their Costs
- For example, margins remained low from 2008–2014 as crude prices were consistently high (prior slide)
- The 2016 margin improvement was linked directly with the steep crude price decline
- 2020's Net Margins were negative despite the Costs being at ~parity with 2000's costs
- Costs and margins rebounded in 2022

Values are indexed to NCM and Costs to Produce Transport Fuels in 2000 and adjusted for inflation

California Crudes' Utilization has Declined

Portion of Crudes Processed that were Produced in California



- The portion of CA crudes processed by CA refiners has declined from ~45% in the early 2000's to ~10% in 2022
- Crude quality impacts aside, Costs will tend to increase when importing more crudes to replace domestic California crude (see next slide for explanation)

Imported Versus California Crudes

- Crude is a global commodity but importing crude increases costs
- For example, a California refiner may be able to source a similar-quality barrel of crude from other parts of the world to replace San Joaquin Valley (SJV)
- While the price of crude in these other locations may be ~ the same as SJV in California, the logistics costs are very different*
  - SJV via pipeline to California refiners is ~1 USD/bbl (lowest costs & risk vs waterborne)
  - Crude from the North Slope of Alaska ~5 USD/bbl
  - Crude from Brazil via ship ~4–5 USD/bbl
  - Crude from the Middle East via ship ~5–6 USD/bbl
- Importing replacement crudes increases inbound logistics costs and generally increases refiners’ costs

* Based on industry general marine freight costs

Key Takeaways

- California (CA) Refiners have faced growing operating cost pressures since 2000
  - Personnel, maintenance, and materials costs have increased by 0.5 → 2x
- CA Refiners' margins – gross and net – have **eroded** since 2000 due to crude price and increased operating cost pressures
  - Crude market pricing impacts both refining margins and, depending on market dynamics, "pump prices" for consumers
- Crude is a global commodity and replacing CA crudes increases costs

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