A New California Oil Boom?

Drilling the Monterey Shale

Part 4: Monterey Shale: Twice as polluting as Keystone XL?

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Editor's note: In Part 1 of our series on the Monterey Shale, Next Generation researcher Robert Collier outlined the technical challenges of developing the Monterey Shale oil field – and how a technique known as "matrix acidizing," which uses hydrofluoric acid to dissolve underground rock formations, may be the key to its development. In Part 2 we explored the risks of widespread HF use and in Part 3 we took a look at the potential impacts of Monterey Shale development on California's emissions goals.

As California decision makers ponder how to plan for a potential new oil boom in the Monterey Shale, they are faced with the daunting task of calculating many complex factors – not only a wide range of oil development scenarios, but also the potential increase in fracking and acidizing, the implications for state budgets, possible impacts on in-state consumption and refinery activities, and serious gaps in understanding of the geologic and environmental issues that may arise with a boom.

Much of California's current petroleum output is categorized as heavy or extra-heavy oil, meaning it is more viscous and requires more energy and time to refine into fuel than lighter grades of crude. In many ways, it is similar to the thick "bitumen" petroleum that comprises Alberta's tar sands. Lighter grades, such as those found in Texas and North Dakota, have lower carbon emissions footprints because they require less energy to extract and refine.

All heavy and extra-heavy grades require a variety of energy-intensive methods to liquefy, extract from the ground, and refine into gasoline, diesel and other transportation fuels. As a result, many California oilfields have greenhouse gas emissions per barrel similar to the Alberta tar sands crudes, according to the California Air Resources Board. In 2007, 70 percent of California's active wells produced extra-heavy or heavy crude, and 56 percent of new wells drilled were extra-heavy or heavy.[1]

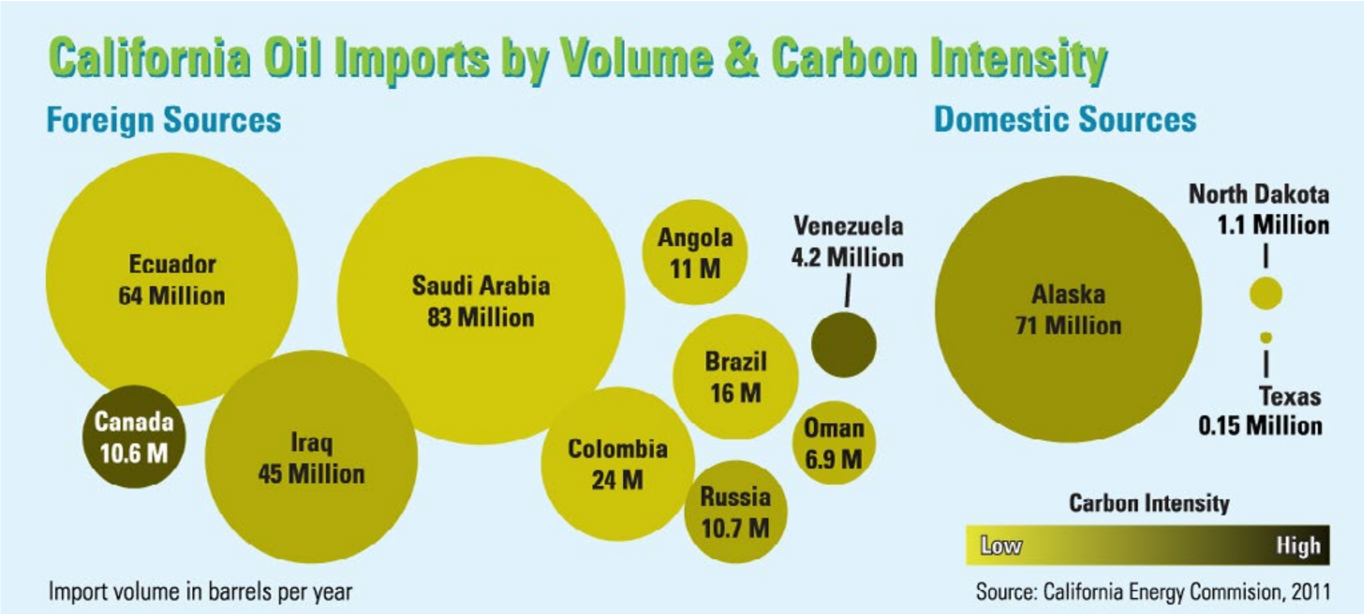
Carbon Intensity of Existing Oil Fields

Top Oil Fields Ranked by Carbon Intensity

1	Round Mtn.	8	Belridge, S.	15	Point Pedernales
2	San Ardo	9	Lost Hills	16	Belridge, N.
3	Coalinga	10	Point Arguello	17	Hondo
4	Poso Creek	11	Inglewood	18	Ventura
5	Kern Front	12	Kern River	19	Pescado
6	Midway-Sunset	13	Elk Hills	20	Sacate
7	Cymric	14	Wilmington		

As a rule of thumb, California's inland oilfields tend to have heavier crude, while coastal and offshore oilfields have lighter varieties. For example, the carbon intensity of the state's largest oilfield, Kern County's Midway-Sunset, and its eighth and ninth largest, San Ardo in Monterey County and Coalinga in Fresno County, are as high or higher than those of the Alberta tar sands. Most oilfields in the San Joaquin Valley are heavy or extra heavy.

In contrast, the oil along the coast tends to be lighter. Many fields in the Los Angeles Basin, Ventura Basin and offshore Santa Barbara produce cleaner burning, light, sweet grades of crude that are as coveted by refiners as the light, sweet blends from Saudi Arabia and Ecuador, California's two leading sources of foreign imported oil.



Legacy of the 1969 spill

Given the disparity in oil types, worries have arisen that the state's climate policies could cause a paradox – pushing the Monterey Shale's coming oil boom into the lighter, cleaner crudes along the coast, rather than into the dirtier, heavier deposits under the badlands of Kern County.

California's oil lobby has warned that, if strict carbon regulations are applied to California crude oil production and refining, they will be forced to conduct a process known as "shuffling," in which California refiners would export the state's heavy, high-carbon oil to other countries, and then import lighter, lower-carbon oil from abroad. They note that only 39 percent of the crude oil refined in California is produced in the state. The remaining 61 percent comes from Alaska or foreign imports via oil tankers, or from western U.S. states by rail. Under shuffling, oil executives say, California oil would likely be replaced by imported sources of light, sweet oil.

Political realities suggest this will not happen. Oil industry lobbyists have recently backtracked on earlier suggestions that they would shuffle their oil supplies. They now say they will go where the political going is easiest – which means staying away from cities and the coast, where memories of the 1969 Santa Barbara offshore oil spill are still vivid and public opposition to oil drilling is strong.

"I don't really expect that there will be much work in the Monterey outside of the San Joaquin Valley, at least for quite a while," said Tupper Hull of the Western States Petroleum Association.[2] "As you know, Los Angeles and the coast is a very strict regulatory environment. The San Joaquin is where most of the resource is."

What's more, the state's complex climate policies may not allow shuffling. Adam Brandt, an assistant professor of Energy Resources Engineering at Stanford University and the state Air Resources Board's chief expert on the climate impact of transportation fuels, says that the state's cap and trade system, which is now in operation, and the Low Carbon Fuel Standard, which is now under court challenge, prohibit shuffling. All in-state sources of crude are averaged in a single basket for greenhouse gas intensity, with no differentiation between companies' individual sources of in-state supply.

"This issue is confusing, I'll admit," said Brandt. "But despite the real disparity in carbon intensity of California crudes, or because of it, the state has deliberately designed its rules to prevent that kind of shuffling."[3]

The upshot of all this is that the dirtiest portions of the Monterey Shale are likely to be developed first, making the overall prospect for an oil boom a distinctly carbon-intensive affair.

Production methods: a primer

Predictions for California's oil industry emissions are also complicated by the lack of clarity about which production methods will be used, and at what depth. Some of these variables could make the Monterey Shale output cleaner than current California crudes, while others would make it dirtier. Here is a summary:

- **Depth.** While oil is found less than 2,000 feet deep in fields like Midway-Sunset, companies must drill to between 6,000 feet and 15,000 feet to tap shale oil in the Monterey. The additional depth requires extra energy for drilling, well completion, pumping and all other activities, all adding up to an approximately 1.3 percent increase in total carbon intensity per 1,000 feet. However, deeper oil tends to be somewhat lighter and less viscous than shallower oil, as explained by Richard Behl, a geologist at CSU Long Beach. "What controls the gravity of oil is what type of organisms were buried there before oil formed …. whether the oil was collecting in reservoir rocks that over geological times was exposed to bacteria and degraded its composition," Behl said. "A lot of shallower deposits are very heavy, but much of the Monterey Shale deposits are more deeply buried, so it probably will be lighter. It's too speculative to say by how much, however."[4]

- **Fracking.** Fracking has long been used in California oil production, with the first occurrence in the Whittier oilfield in 1953. However, oil industry officials say that because of the complex nature of the Monterey Shale, fracking may be ineffective in many areas and other techniques such as acidizing may be more effective. However, no information is available about energy intensity of the fracking process. Stanford's Adam Brandt says he is only now starting the months-long process of crunching that data for the ARB. Because fracking is currently unregulated and no reporting of the practice is required, state regulators do not know what proportion of the state's oil is produced through fracking.

- **Steam injection.** This method – the injection of hot water vapor downhole – is a common way of melting extra-heavy crude that is too tar-like to be easily extracted through conventional drilling. Steam injection is by far the most energy-intensive and water intensive method used in California oil extraction. In 2007, 23 of the state's 153 oilfields used steam injection, according to ARB data. A similar method is hot water flooding, which injects hot water instead of steam. Steam generation represents 41 percent of the California oil and gas industry's GHG emissions, while combined heat and power (which includes hot water heating and other drilling-related electricity use) causes another 22 percent, according to the ARB.

"When you see high values for carbon intensity at California oilfields, it's almost always due in large part to steam injection or waterflooding," said Brandt.[5] He said the methods for extracting the Monterey Shale's crude will be similar to anyone following the national debate over the Keystone XL pipeline. "You have extra-heavy crude, and the only way to get it out is via a process very similar to the 'in situ' production of the tar sands," he said, referring to the Canadian practice of pumping steam down into the oil-bearing strata and waiting for the heat to melt the tar-like, compacted sands into a liquid that can be pumped up to the surface.

For the most part, Brandt noted, steam injection and hot waterflooding currently are used in relatively shallow depths in California, to a maximum of approximately 5,000 feet. While it is likely these methods will be adapted to the Monterey Shale, there is no guarantee they will be used at a greater rate than currently.

- **Acidizing.** As discussed in Next Generation's two-part report about acidizing, oil companies operating in California say that many areas of the Monterey Shale do not respond well to fracking and instead give better results through the process of acidizing, which includes matrix acidizing and acid fracking. In these methods, large volumes of hydrofluoric acid are injected into the substrata to dissolve the rock and open up fractures so that the oil can flow. As with fracking, this practice is largely unregulated, so no information is available about what proportion of the state's oil is extracted via acidizing, and no research has been carried out about the carbon intensity of acidizing.

- **Clean tech.** State regulators have created a system of incentives to support the use of "clean distributed generation technologies" to replace the natural gas that fires the steam flooding process and other oil well activities. These include a complex variety of low-carbon technologies – microturbines, fuel cells, and a thermal oxidizer integrated with a microturbine. One especially promising method is solar thermal enhanced oil recovery, with two test projects currently underway – Berry Petroleum with GlassPoint Solar in McKittrick, Kern County, and Chevron's partnership with BrightSource Energy near Coalinga. In both cases, an array of solar concentrating mirrors tracks the sun, captures rays, then shines the concentrated light to heat the water into steam, which is then pumped down into the oil reservoir. This method is estimated to cut CO_2 emissions of oil extraction by up to 80 percent. All these projects are experimental, with no guarantee that they will prove successful or be used widely in the Monterey – or in other shale formations around the country or world.

A USA worth of emissions? Or two Keystones?

There are two ways of comparing greenhouse gas emissions for the California oil industry: A broader scope, known as the "well-to-wheel lifecycle" approach, which adds the cumulative total of emissions from the oil's production and final consumption, regardless of where the oil is eventually used, over the project's entire lifetime; and a narrower scope that measures the annual rate of in-state emissions from the "upstream" process of drilling, extracting and transporting the oil but does not measure refining or consumption.

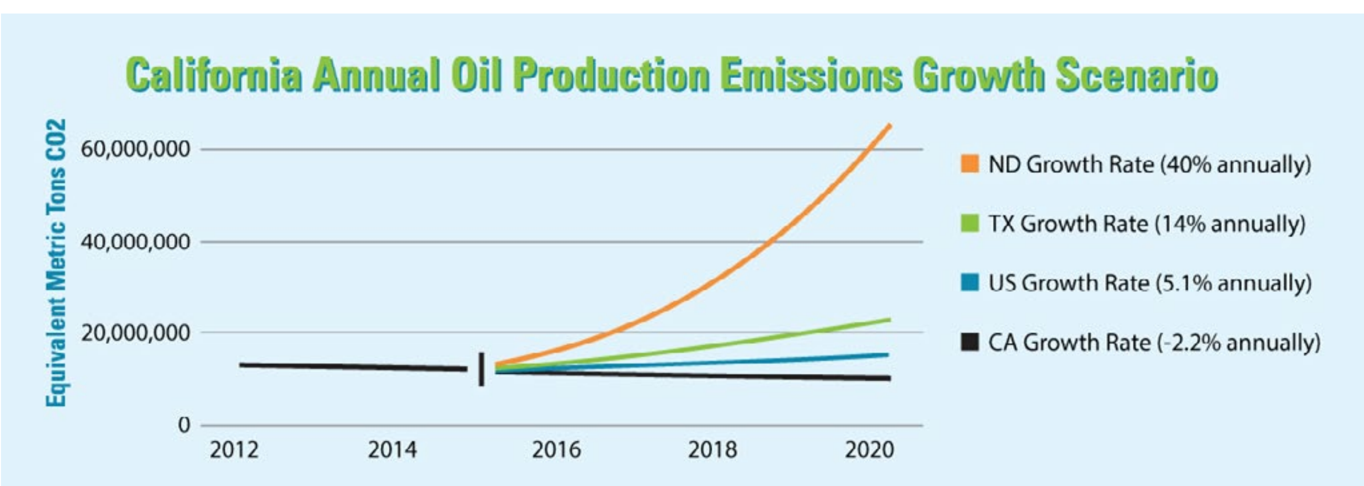
Both yardsticks have their weaknesses. The well-to-wheel lifecycle approach might exaggerate the net carbon impact if Monterey Shale oil simply displaces imported sources of oil, and if it does not increase end-use consumption by the state's transportation sector. The upstream-only approach does not show the overall impact on global greenhouse gas emissions of an up-or-down decision to develop the oil or instead leave all of it in the ground.

Well to wheel lifecycle approach. According to calculations by Argonne National Laboratory using data from ARB, the lifecycle emissions – extracting, transporting, refining and consuming – of the average barrel of California oil are equivalent to 0.5 metric tons of carbon dioxide.[6] As a result, production of the Monterey Shale's entire 15.4 billion barrels would release 7.7 billion metric tons of carbon dioxide, equivalent to 17 years of California's total greenhouse gas emissions at 2010 levels, or about one year of total emissions for the United States.

This approach essentially measures the carbon cost of extracting the oil rather than leaving all of it untapped. Of course, there is no guarantee that the Monterey's 15.4 billion barrels could actually be extracted. Given the current technical difficulties in accessing the oil amid its jumbled formations, there is a real possibility that a significantly lower proportion of that resource will be used. Nor is the speed of this process at all clear – over a few decades, or stretched out over a century? Another difficulty with this approach is that it does not recognize the likelihood that the Monterey's production would displace imported supplies of crude, making little measurable impact on the in-state emissions of California's own transportation sector. All these caveats suggest some caution in drawing conclusions.

Upstream only. It's possible to construct a range of possible emissions scenarios by taking three potential rates of growth for the Monterey Shale, based on output rates in other states from 2007 to 2012 – the North Dakota rate of 40 percent annual increase, the Texas rate of 14 percent, and the nationwide U.S. rate of 5.1 percent. Based on these scenarios, the California oil and gas industry's annual output of greenhouse gases would rise by the following amounts from approximately 12.5 million metric tons of CO2 equivalent in 2015.

The policy implications of the above scenarios vary wildly. The state's climate plan mandates that 80 million metric tons must be cut from the state's overall annual emissions by 2020. If the state's oil output were to grow by the U.S. rate, the impact on the climate plan's goals would be moderate – still a step backward, but not unmanageable. If it



were to grow by the North Dakota rate, however, the impact would be severe, forcing more drastic cuts in emissions elsewhere.

Another point of comparison is the projected annual rate of emissions from the oil transported by the Keystone XL pipeline, which the U.S. Environmental Protection Agency has estimated at 27 million metric tons. If the California oil industry's output were to grow at the North Dakota rate, its emissions would be twice as large as the Keystone XL emissions.

The above growth scenarios do not include significant increases in refinery emissions.[7] The state's 18 refineries have a total capacity of about 2 million barrels per day, of which California's current oil production supplies only about one-quarter. Federal law strictly limits crude oil exports from the United States to foreign nations; given the lack of any major oil pipelines that could send California crude to other states, it seems likely that most, if not all, Monterey Shale oil will remain in-state and will merely replace supplies of crude that are currently imported.

In addition, California's refining capacity is configured for a wide range of oil viscosity, including heavy imported crude. So a switch to local supplies would have little net effect on refineries' energy use and emissions – leaving no basis to assume any substantial change of the refinery sector's emissions under any of these scenarios.

For now, the Monterey Shale remains a mirage waiting to become reality. The wide gamut of possible scenarios – boom, mini-boom or bust? – means that the jury is still out on the possible climate impact of a net increase in oil production. As with other facets of the national and global debates over climate change, much remains unknown.

But the success of California's landmark climate policies are clearly at stake. Time will tell if the state's leaders will remain as committed to existing climate goals when – and if – the black gold starts flowing from the Monterey Shale.

Notes

1 With API under 10 and 20, respectively.

2 Interview, May 14, 2013.

3 Interview, May 24, 2013.

4 Telephone interview, May 13, 2013

5 Interview, May 24, 2013.

6 Email to author, July 25, 2013, from Amgad Elgowainy, Principal Energy Systems Analyst of the Argonne National Laboratory's Center for Transportation Research.

7 In recent months, the Western States Petroleum Association and researchers at UC Davis have engaged in a vigorous back-and-forth debate over the effects of AB 32 on the refining sector. These important issues are separate from the subject matter at hand.