DOCKETED

Docket Number:	21-BSTD-02
Project Title:	2022 Energy Code Update CEQA Documentation
TN #:	238766
Document Title:	Holland & Knight LLP Comments - Holland & Knight References (7 of 11)
Description:	N/A
Filer:	System
Organization:	Holland & Knight LLP
Submitter Role:	Public
Submission Date:	7/8/2021 4:59:42 PM
Docketed Date:	7/8/2021

Comment Received From: Holland & Knight LLP
Submitted On: 7/8/2021
Docket Number: 21-BSTD-02

Holland & Knight References (7 of 11)

The attached document is the seventh of 11 separate uploads that contain the references cited in Holland & Knight's DEIR Comment Letter.

Additional submitted attachment is included below.

ENERGY STORAGE

It’s time to get serious about recycling lithium-ion batteries

A projected surge in electric-vehicle sales means that researchers must think about conserving natural resources and addressing battery end-of-life issues

by ***Mitch Jacoby***

July 14, 2019 | A version of this story appeared in **Volume 97, Issue 28**

plant near Vancouver, British Columbia, American Manganese engineers examine shredded aluminum recovered from Li-ion battery cathodes.

A ... vehicles starts to grow explosively, so does the pile of spent lithium-ion batteries that once powered those cars. Industry analysts predict that by 2020, China alone will generate some 500,000 metric tons of used Li-ion batteries and that by 2030, the worldwide number will hit 2 million metric tons per year.

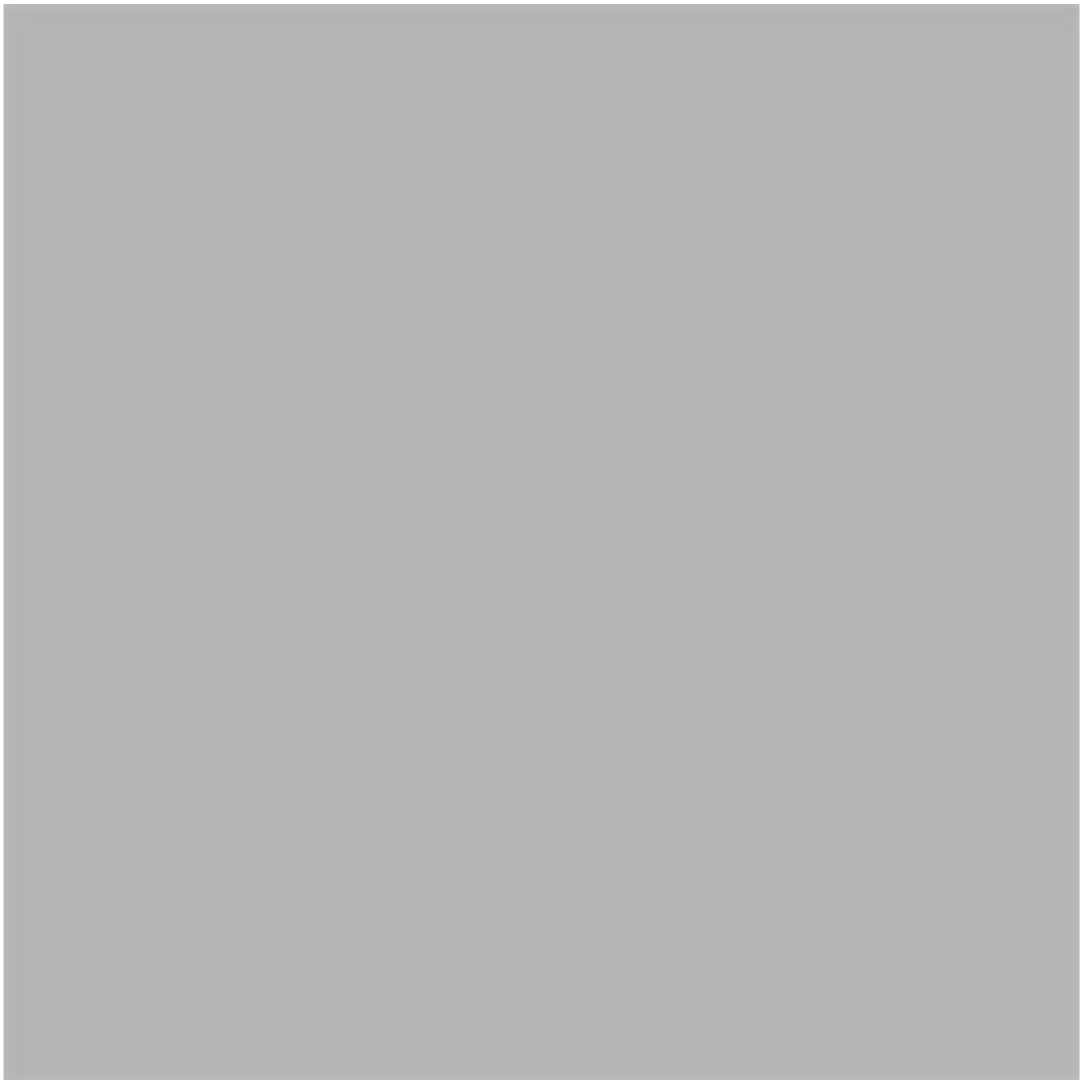
If current trends for handling these spent batteries hold, most of those batteries may end up in landfills even though Li-ion batteries can be recycled. These popular power packs contain valuable metals and other materials that can be recovered, processed, and reused. But very little recycling goes on today. In Australia, for example, only 2–3% of Li-ion batteries are collected and sent offshore for recycling, according to Naomi J. Boxall, an environmental scientist at Australia’s Commonwealth Scientific and Industrial Research Organisation (CSIRO). The recycling rates in the European Union and the US—less than 5%—aren’t much higher.

“There are many reasons why Li-ion battery recycling is not yet a universally well-established practice,” says Linda L. Gaines of Argonne National Laboratory. A specialist in materials and life-cycle analysis, Gaines says the reasons include technical constraints, economic barriers, logistic issues, and regulatory gaps.

IN BRIEF

Lithium-ion batteries have made portable electronics ubiquitous, and they are about to do the same for electric vehicles. That success story is setting the world on track to generate a multimillion-metric-ton heap of used Li-ion batteries that could end up in the trash. The batteries are valuable and recyclable, but because of technical, economic, and other factors, less than 5% are recycled today. The enormousness of the impending spent-battery situation is driving researchers to search for cost-effective, environmentally sustainable strategies for dealing with the vast stockpile of Li-ion batteries looming on the horizon.

All those issues feed into a classic chicken-and-egg problem. Because the Li-ion battery industry lacks a clear path to large-scale economical recycling, battery researchers and manufacturers have traditionally not focused on improving recyclability. Instead, they have worked to lower costs and increase battery longevity and charge capacity. And because researchers have made only modest progress improving recyclability, relatively few Li-ion batteries end up being recycled.



Credit: Mitch Jacoby/C&EN

The large, inverted, T-shaped object that fills this travel case (black) is an approximately 200 kg Chevy Volt battery pack. Propped on top of it, at left, is a postcard-sized pouch battery, 288 of which make up the Volt's battery pack. For scale, a cell phone battery is shown in the center and an iPad battery at right.

Most of the batteries that do get recycled undergo a high-temperature melting-and-extraction, or smelting, process similar to ones used in the mining industry. Those operations, which are carried out in large commercial facilities—for example, in Asia, Europe, and Canada—are energy intensive. The plants are also costly to build and operate and require sophisticated equipment to treat harmful emissions generated by the smelting process. And despite the high costs, these plants don't recover all valuable battery materials.

Until now, most of the effort to improve Li-ion battery recycling has been concentrated in a relatively small number of academic research groups, generally working independently. But things are starting to change. Driven by the enormous quantity of spent Li-ion batteries expected soon from aging electric vehicles and ubiquitous portable electronics, start-up companies are commercializing new battery-recycling technology. And more scientists have started to study the problem, expanding the pool of graduate students and postdocs newly trained in battery recycling. In addition, some battery, manufacturing, and recycling experts have begun forming large, multifaceted collaborations to tackle the impending problem.

In January, for example, US Department of Energy secretary Rick Perry announced the creation of the DOE's first Li-ion battery recycling R&D center, the ReCell Center. According to Jeffrey S. Spangenberger, the program's director, ReCell's key goals include making Li-ion battery recycling competitive and profitable and using recycling to help reduce US dependence on foreign sources of cobalt and other battery materials. Launched with a $15 million investment and headquartered at Argonne National Laboratory, ReCell includes some 50 researchers based at six national laboratories and universities. The program also includes battery and automotive equipment manufacturers, materials suppliers, and other industry partners.

At the same time, the DOE also launched the $5.5 million Battery Recycling Prize. The program's goal is to encourage entrepreneurs to find innovative solutions for collecting and storing discarded Li-ion batteries and transporting them to recycling centers, which are the first steps in turning old batteries into new ones.

And last year, researchers in the UK formed a large consortium dedicated to improving Li-ion battery recycling, specifically from electric vehicles. Led by the University of Birmingham, the Reuse and Recycling of Lithium Ion Batteries (ReLiB) project brings together some 50 scientists and engineers at eight academic institutions, and it includes 14 industry partners.

Related: Lowering the cost of grid-storage batteries

RECYCLING'S BENEFITS

Battery specialists and environmentalists give a long list of reasons to recycle Li-ion batteries. The materials recovered could be used to make new batteries, lowering manufacturing costs. Currently, those materials account for more than half of a battery's cost. The prices of two common cathode metals, **cobalt** and nickel, the most expensive components, have fluctuated substantially in recent years. Current market prices for cobalt and nickel stand at roughly $27,500 per metric ton and $12,600 per metric ton, respectively. In 2018, cobalt's price exceeded $90,000 per metric ton.

In many types of Li-ion batteries, the concentrations of these metals, along with those of lithium and manganese, exceed the concentrations in natural ores, making spent batteries akin to highly enriched ore. If those metals can be recovered from used batteries at a large scale and more economically than from natural ore, the price of batteries and electric vehicles should drop.

In addition to potential economic benefits, recycling could reduce the quantity of material going into landfills. Cobalt, nickel, manganese, and other metals found in batteries can readily leak from the casing of buried batteries and contaminate soil and groundwater, threatening ecosystems and human health, says Zhi Sun, a specialist in pollution control at the Chinese

BY THE NUMBERS

140 million: The number of electric vehicles predicted to be on the road worldwide by 2030

11 million: Metric tons of Li-ion batteries expected to reach the end of their service lives between now and 2030

30–40%: The percentage of a Li-ion battery's weight that comes from valuable cathode material

<5%: The percentage of Li-ion batteries that are recycled currently

~100%: The percentage of the lead in common lead-acid car batteries that gets recycled into new batteries

~$70 billion: The value of the Li-ion battery market projected for 2022

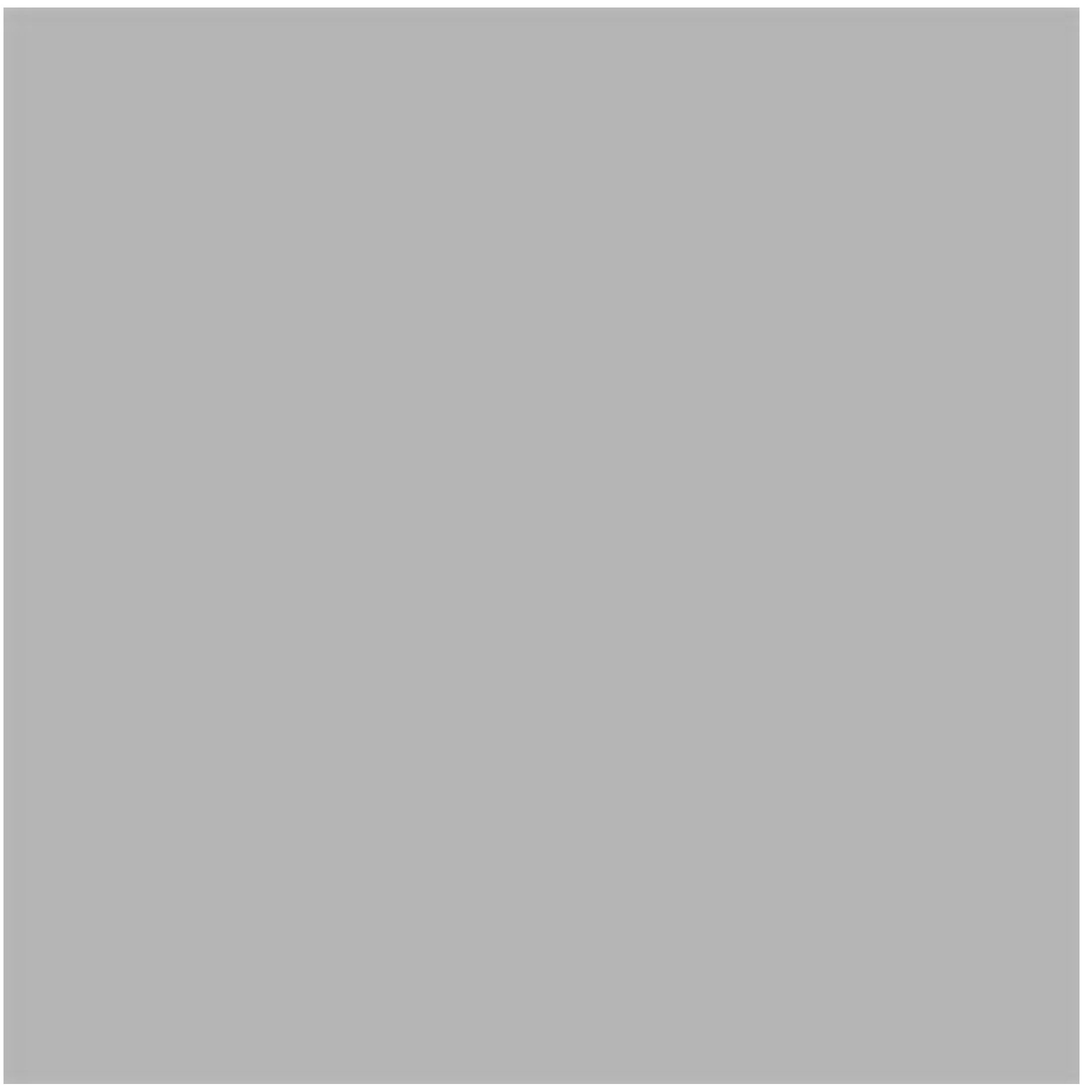
Academy of Sciences. The same is true of the solution of lithium fluoride salts ($LiPF_6$ is common) in organic solvents that are used in a battery's electrolyte.

Sources: International Energy Agency, US Department of Energy.

Batteries can have negative environmental effects not just at the end of their lives but also long before they are manufactured. As Argonne's Gaines points out, more recycling means less mining of virgin material and less of the associated environmental harm. For example, mining for some battery metals requires processing metal-sulfide ore, which is energy intensive and emits SO_x that can lead to acid rain.

Less reliance on mining for battery materials could also slow the depletion of these raw materials. Gaines and Argonne coworkers studied this issue using computational methods to model how growing battery production could affect the geological reserves of a number of metals through 2050. Acknowledging that these predictions are "complicated and uncertain," the researchers found that world reserves of lithium and nickel are adequate to sustain rapid growth of battery production. But battery manufacturing could decrease global cobalt reserves by more than 10%.

There are also political costs and downsides that recycling Li-ion batteries could help address. According to **a CSIRO report**, 50% of the world's production of cobalt comes from the Democratic Republic of the Congo and is tied to armed conflict, illegal mining, human rights abuses, and harmful environmental practices. Recycling batteries and formulating cathodes with a reduced concentration of cobalt could help lower the dependence on such problematic foreign sources and raise the security of the supply chain.



Credit: Mitch Jacoby/C&EN

Argonne National Laboratory's Dohyeun Kim prepares pouch-type Li-ion batteries to study battery recycling.

CHALLENGES IN RECYCLING LI-ION BATTERIES

Just as economic factors can make the case for recycling batteries, they also make the case against it. Large fluctuations in the prices of raw battery materials, for example, cast uncertainty on the economics of recycling. In particular, the recent large drop in cobalt's price raises questions about whether recycling Li-ion batteries or repurposing them is a good business choice compared with manufacturing new batteries with fresh materials. Basically, if the price of cobalt drops, recycled cobalt would struggle to compete with mined cobalt in terms of price, and manufacturers would choose mined material over recycled, forcing recyclers out of business. Another long-term financial concern for companies considering stepping into battery recycling is whether a different type of battery, such as **Li air**, or a different vehicle propulsion system, like **hydrogen-powered fuel cells**, will gain a major foothold on the electric-vehicle market in coming years, lowering the demand for recycling Li-ion batteries.

Battery chemistry also complicates recycling. Since the early 1990s when Sony commercialized Li-ion batteries, researchers have repeatedly tailored the cathode's composition to reduce cost and to enhance charge capacity, longevity, recharge time, and other performance parameters.

Some Li-ion batteries use cathodes made of lithium cobalt oxide (LCO). Others use lithium nickel manganese cobalt oxide (NMC), lithium nickel cobalt aluminum oxide, lithium iron phosphate, or other materials. And the proportions of the components within one type of cathode—for example, NMC—can vary substantially among manufacturers. The upshot is that Li-ion batteries contain "a wide diversity of ever-evolving materials, which makes recycling challenging," says Liang An, a battery-recycling specialist at Hong Kong Polytechnic University. Recyclers may need to sort and separate batteries by composition to meet the specifications of people buying the recycled materials, making the process more complicated and raising costs.

Battery structure further complicates recycling efforts. Li-ion batteries are compact, complex devices, come in a variety of sizes and shapes, and are not designed to be disassembled. Each cell contains a cathode, anode, separator, and electrolyte.

Cathodes generally consist of an electrochemically active powder (LCO, NMC, etc.) mixed with carbon black and glued to an aluminum-foil current collector with a polymeric compound such as poly(vinylidene fluoride) (PVDF). Anodes usually contain graphite, PVDF, and copper foil. Separators, which insulate the electrodes to prevent short circuiting, are thin, porous plastic films, often polyethylene or polypropylene. The electrolyte is typically a solution of $LiPF_6$ dissolved in a mixture of ethylene carbonate and dimethyl carbonate. The components are tightly wound or stacked and packed securely in a plastic or aluminum case.

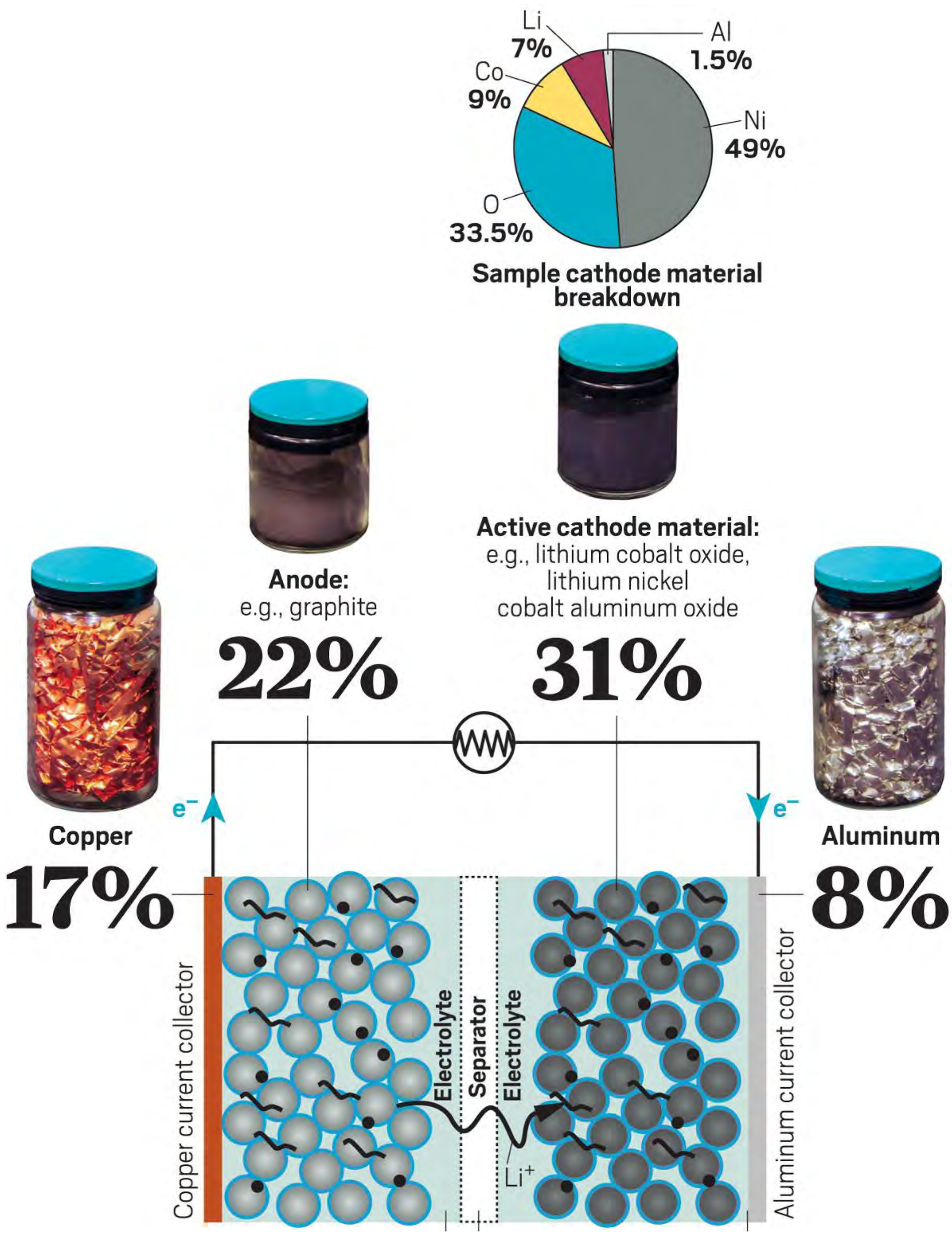
Related: Making lithium-ion batteries more environmentally friendly

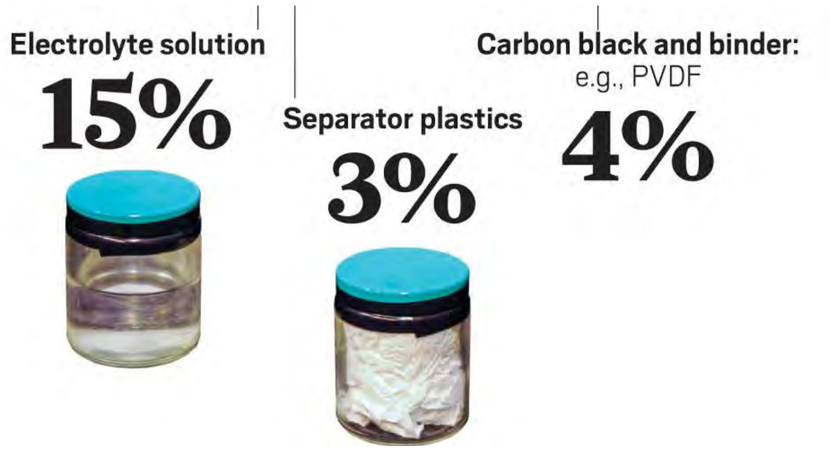
Large battery packs that power electric vehicles may contain several thousand cells grouped in modules. The packs also include sensors, safety devices, and circuitry that controls battery operation, all of which add yet another layer of complexity and additional costs to dismantling and recycling.

All these battery components and materials need to be dealt with by a recycler to get at the valuable metals and other materials. In stark contrast, lead-acid car batteries are easily disassembled, and the lead, which accounts for about 60% of a battery's weight, can be separated quickly from the other components. As a result, **nearly 100% of the lead** in these batteries is recycled in the US, far surpassing **recycling rates for glass**, paper, and other materials.

Inside a Li-ion battery

All the components of a Li-ion battery have value and can be recovered and reused. Currently, most recyclers recover just the metals. The pie chart describes a cathode material known as NCA, which is made of lithium nickel cobalt aluminum oxide.





Credit: Mitch Jacoby/C&EN

Source: Argonne National Laboratory.

IMPROVING RECYCLING METHODS

Several large pyrometallurgy, or smelting, facilities recycle Li-ion batteries today. These units, which often run near 1,500 °C, recover cobalt, nickel, and copper but not lithium, aluminum, or any organic compounds, which get burned. The facilities are capital intensive, in part because of the need to treat the emission of toxic fluorine compounds released during smelting.

Hydrometallurgy processing, or chemical leaching, which is practiced commercially in China, for example, offers a less energy-intensive alternative and lower capital costs. These processes for extracting and separating cathode metals generally run below 100 °C and can recover lithium and copper in addition to the other transition metals. One downside of traditional leaching methods is the need for caustic reagents such as hydrochloric, nitric, and sulfuric acids and hydrogen peroxide.

Researchers running bench-scale studies have identified potential improvements to these recycling methods, but only a handful of companies run recycling tests on the methods at the pilot-plant scale. In the Vancouver, British Columbia, area, an American Manganese facility converts 1 kg/h of cathode scrap to a precursor that manufacturers can use to synthesize fresh cathode material. Scrap refers to off-spec cathode powder, trimmings, and other waste collected from battery manufacturing.

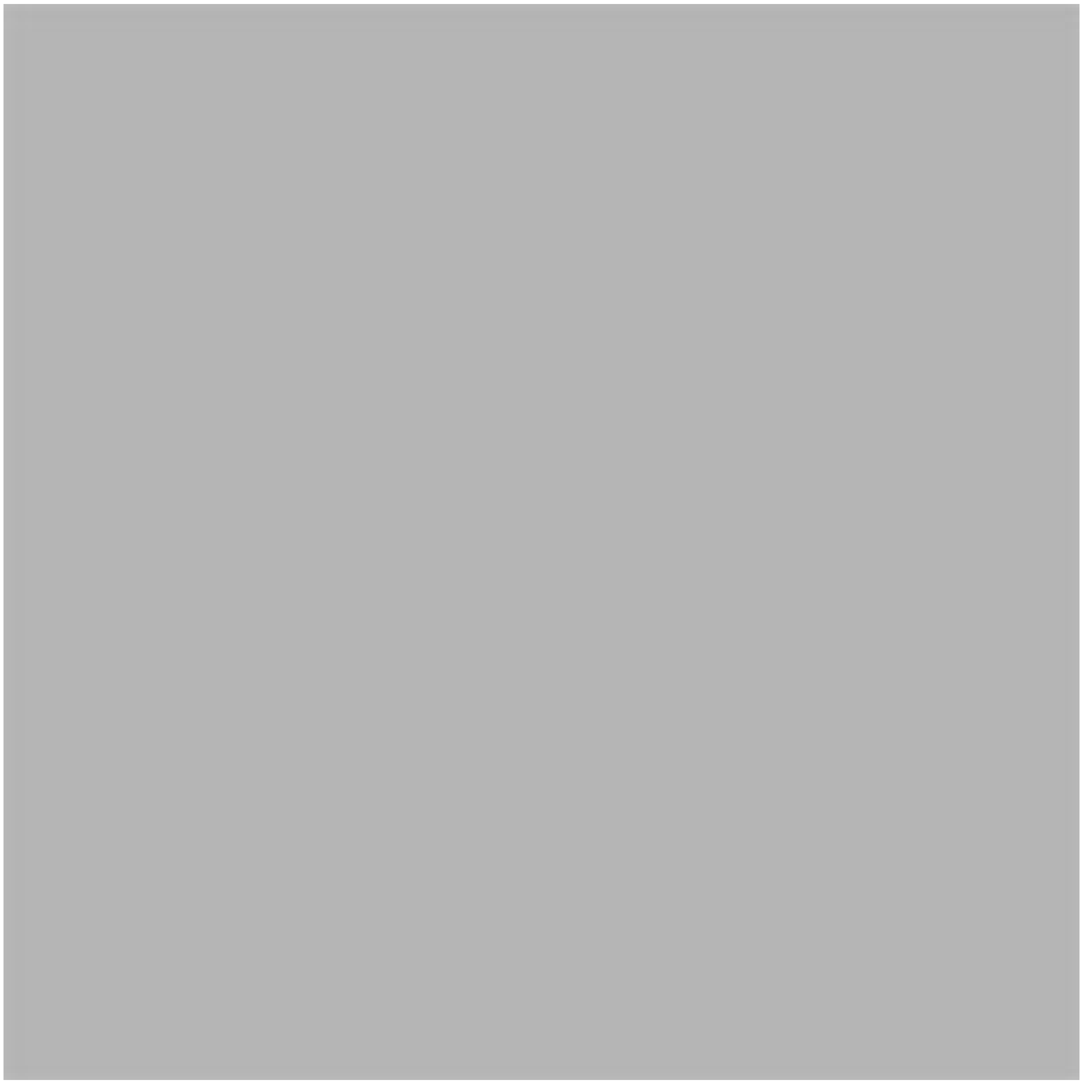
Zarko Meseldzija, the company's chief technical officer, describes the scrap as "low-hanging fruit," a convenient material to use for experiments before boosting the scale of operations and moving on to actual spent batteries. He explains that the company's process relies on sulfur dioxide for leaching cathode metals and does not use hydrochloric acid or hydrogen peroxide.

Battery Resourcers in Worcester, Massachusetts, runs a pilot plant that processes Li-ion batteries at a rate of up to roughly 0.5 metric tons per day and is actively working to increase capacity by a factor of 10, according to CEO Eric Gratz. Many current recycling methods yield multiple single-metal compounds that must be combined to make new cathode material. Battery Resourcers' process precipitates a mixture of nickel, manganese, and cobalt hydroxides. This mixed-metal cathode precursor simplifies battery preparation and could lower manufacturing costs.

Related: Recycling renewables

Meanwhile, the DOE's ReCell team is pursuing so-called direct recycling methods for recovering and reusing battery materials without costly processing. One approach calls for removing the electrolyte with supercritical carbon dioxide, then crushing the cell and separating the components physically—for example, on the basis of density differences.

In principle, nearly all the components can be reused after this simple processing. In particular, because the method does not use acids or other harsh reagents, the morphology and crystal structure of the cathode materials remain intact, and the materials retain the electrochemical properties that make them valuable. Gaines says more work is needed to implement this cost-saving approach.



Credit: Alireza Rastegarpanah and Rustam Stolkin/Extreme Robotics Lab

At the University of Birmingham, ReLib team member Alireza Rastegarpanah develops robotic methods for safe, automated processing of spent Li-ion batteries.

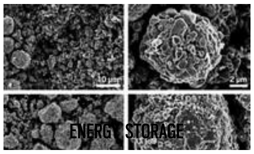
At the University of Birmingham's ReLiB project, principal investigator Paul Anderson says the team sees a clear opportunity to boost the economic efficiency of battery recycling through automation. To that end, the team is developing robotic procedures for sorting, disassembling, and recovering valuable materials from Li-ion batteries. Birmingham's Allan Walton, a coinvestigator, adds that using robotic devices to disassemble batteries could eliminate human workers' risk of electrical and chemical injury. Automation could also lead to enhanced separation of battery components, increasing their purity and value, he says.

Although most of these strategies remain at an early stage of development, the need for them is growing. Currently, the number of end-of-life electric-vehicle batteries is low, but it's about to skyrocket. Numerous impediments stand in the way of large-scale recycling, but "opportunities always coexist with challenges," says An of Hong Kong Polytechnic. It's time to take the bull by the horns and get serious about recycling Li-ion batteries.

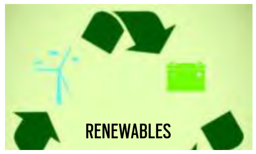
Chemical & Engineering News
ISSN 0009-2347

YOU MIGHT ALSO LIKE...

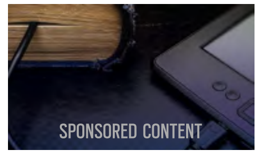
Lowering the cost of grid-storage batteries



Making lithium-ion batteries more environmentally friendly



Recycling renewables



COMMENTS

TITO CALOI
(November 6, 2019 3:47 PM)
It'ld be better to recover the battery instead of recover the materials there is inside.

Tim Moss
(December 27, 2019 3:59 AM)
Totally agree with what's written above. We need to find a way of recycling the lithium ion batteries. We have a mass problem on our hands with the introduction of electric vehicles into the automotive industry. My hope would be to reuse them in areas such as manufacturing and engineering to power machine tools.

JOIN THE CONVERSATION

Contact the reporter

Submit a Letter to the Editor for publication

Engage with us on Twitter

The cobalt pipeline

washingtonpost.com/graphics/business/batteries/congo-cobalt-mining-for-lithium-ion-battery

×

Tracing the path from deadly hand-dug mines in Congo to consumers' phones and laptops

Story by Todd C. Frankel Photos by Michael Robinson Chavez Video editing by Jorge Ribas
September 30, 2016

Africa

S. SUDAN

REP. OF

CONGO

CONGO

Kinshasa

TANZ.

Kolwezi

ANGOLA

Lubumbashi

The sun was rising over one of the richest mineral deposits on Earth, in one of the poorest countries, as Sidiki Mayamba got ready for work.

Mayamba is a cobalt miner. And the red-dirt savanna stretching outside his door contains such an astonishing wealth of cobalt and other minerals that a geologist once described it as a “scandale geologique.”

This remote landscape in southern Africa lies at the heart of the world’s mad scramble for cheap cobalt, a mineral essential to the rechargeable lithium-ion batteries that power smartphones, laptops and electric vehicles made by companies such as Apple, Samsung and major automakers.

But Mayamba, 35, knew nothing about his role in this sprawling global supply chain. He grabbed his metal shovel and broken-headed hammer from a corner of the room he shares with his wife and child. He pulled on a dust-stained jacket. A proud man, he likes to wear a button-down shirt even to mine. And he planned to mine by hand all day and through the night. He would nap in the underground tunnels. No industrial tools. Not even a hard hat. The risk of a cave-in is constant.

“Do you have enough money to buy flour today?” he asked his wife.

She did. But now a debt collector stood at the door. The family owed money for salt. Flour would have to wait.

Mayamba tried to reassure his wife. He said goodbye to his son. Then he slung his shovel over his shoulder. It was time.

The world’s soaring demand for cobalt is at times met by workers, including children, who labor in harsh and dangerous conditions. An estimated 100,000 cobalt miners in Congo use hand tools to dig hundreds of feet underground with little oversight and few safety measures, according to workers, government officials and evidence found by The Washington Post during visits to remote mines. Deaths and injuries are common. And the mining activity exposes local communities to levels of toxic metals that appear to be linked to ailments that include breathing problems and birth defects, health officials say.

A “creuseur,” or digger, climbs through a cobalt and copper mine in Kawama, Congo, in June.

The Post traced this cobalt pipeline and, for the first time, showed how cobalt mined in these harsh conditions ends up in popular consumer products. It moves from small-scale Congolese mines to a single Chinese company — Congo DongFang International Mining, part of one of the world’s biggest cobalt producers, Zhejiang Huayou Cobalt — that for years has supplied some of the world’s largest battery makers. They, in turn, have produced the batteries found inside products such as Apple’s iPhones — a finding that calls into question corporate assertions that they are capable of monitoring their supply chains for human rights abuses or child labor.

Mobile power, human toll

The world has grown reliant on lithium-ion batteries that power smartphones, laptops and electric cars. But the desperate search for the ingredients carries a steep cost.

More in this series: Graphite in China and Lithium in Argentina

Apple, in response to questions from The Post, acknowledged that this cobalt has made its way into its batteries. The Cupertino, Calif.-based tech giant said that an estimated 20 percent of the cobalt it uses comes from Huayou Cobalt. Paula Pyers, a senior director at Apple in charge of supply-chain social responsibility, said the company plans to increase scrutiny of how all its cobalt is obtained. Pyers also said Apple is committed to working with Huayou Cobalt to clean up the supply chain and to addressing the underlying issues, such as extreme poverty, that result in harsh work conditions and child labor.

Another Huayou customer, LG Chem, one of the world's leading battery makers, told The Post it stopped buying Congo-sourced minerals late last year. Samsung SDI, another large battery maker, said that it is conducting an internal investigation but that "to the best of our knowledge," while the company does use cobalt mined in Congo, it does not come from Huayou.

Few companies regularly track where their cobalt comes from. Following the path from mine to finished product is difficult but possible, The Post discovered. Armed guards block access to many of Congo's mines. The cobalt then passes through several companies and travels thousands of miles.

Yet 60 percent of the world's cobalt originates in Congo — a chaotic country rife with corruption and a long history of foreign exploitation of its natural resources. A century ago, companies plundered Congo's rubber sap and elephant tusks while the country was a Belgian colony. Today, more than five decades after Congo gained its independence, it is minerals that attract foreign companies.

Scrutiny is heightened for a few of these minerals. A 2010 U.S. law requires American companies to attempt to verify that any tin, tungsten, tantalum and gold they use is obtained from mines free of militia control in the Congo region. The result is a system widely seen as preventing human rights abuses. Some say cobalt should be added to the conflict-minerals list, even if cobalt mines are not thought to be funding war. Apple told The Post that it now supports including cobalt in the law.

Congo's cobalt trade has been the target of criticism for nearly a decade, mostly from advocacy groups. Even U.S. trade groups have acknowledged the problem. The Electronic Industry Citizenship Coalition — whose members include companies such as Apple — raised concerns in 2010 about the potential for human rights abuses in the mining of minerals, including cobalt, and the difficulty in tracking supply chains. The U.S. Labor Department lists Congolese cobalt as a product it has reason to think is produced by child labor.

Concern about how cobalt is mined "comes to the fore every now and again," said Guy Darby, a veteran cobalt analyst with Darton Commodities in London. "And it's met with much muttering and shaking of the head and tuttering — and goes away again."

In the past year, a Dutch advocacy group called the Center for Research on Multinational Corporations, known as SOMO, and Amnesty International have put out reports alleging improprieties including forced relocations of villages and water pollution. Amnesty's report, which accused Congo DongFang of buying materials mined by children, prompted a fresh wave of companies to promise that their cobalt connections were being vetted.

But the problems remained starkly evident when Post journalists visited mining operations in Congo this summer.

Digger Sidiki Mayamba, left, puts on his shoes in the room he shares with wife Ivette Mujombo Tshatela and their 2-year-old son, Harold Muhiya Mwehu, in Kolwezi, Congo, in June. "Creuseurs," or diggers, work in the mine at Kawama. The cobalt that is extracted is sold to a Chinese company, Congo DongFang Mining. A man pushes a bicycle laden with charcoal, which is used for cooking and heating, past Musompo, a mineral market outside Kolwezi. A boy carries a bag used to transport cobalt-laden dirt and rock at the Musompo market.

In September, Chen Hongliang, the president of Congo DongFang parent Huayou Cobalt, told The Post that his company had never questioned how its minerals were obtained, despite operating in Congo and cities such as Kolwezi for a decade.

"That is our shortcoming," Chen said in an interview in Seattle, in his first public comments on the topic. "We didn't realize."

Chen said Huayou planned to change how it buys cobalt, had hired an outside company to oversee the process and was working with customers such as Apple to create a system for preventing abuse.

But how such serious problems could persist for so long — despite frequent warning signs — illustrates what can happen in hard-to-decipher supply chains when they are mostly unregulated, low price is paramount and the trouble occurs in a distant, tumultuous part of the world.

Amount of cobalt in different devices

Smartphone

5 to 10 grams

(as heavy as 2 to 4 pennies)

Laptop

1 ounce

(a slice of bread)

Typical electric car

10 to 20 pounds

(2 to 3 gallons of milk)

Lithium-ion batteries were supposed to be different from the dirty, toxic technologies of the past. Lighter and packing more energy than conventional lead-acid batteries, these cobalt-rich batteries are seen as “green.” They are essential to plans for one day moving beyond smog-belching gasoline engines. Already these batteries have defined the world’s tech devices.

Smartphones would not fit in pockets without them. Laptops would not fit on laps. Electric vehicles would be impractical. In many ways, the current Silicon Valley gold rush — from mobile devices to driverless cars — is built on the power of lithium-ion batteries.

But this comes at an exceptional cost.

“It is true, there are children in these mines,” provincial governor Richard Muyej, the highest-ranking government official in Kolwezi, said in an interview. He also acknowledged problems with mining-related deaths and pollution.

But, he said, his government is too poor to tackle these issues alone.

“The government is not a beggar,” Muyej said. “These companies have an obligation to create wealth in the area where they operate.”

Companies are unlikely to abandon Congo, for a simple reason: The world needs what Congo has.

Chen said he expected controversy surrounding how cobalt is mined in Congo to ripple far beyond Huayou Cobalt.

“This issue, I believe, we are not the only ones,” he said. “We believe there are many companies in similar situations as us.”

‘Lungs of the Congo’

The worst conditions affect Congo’s “artisanal” miners — a too-quaint name for the impoverished workers who mine without pneumatic drills or diesel draglines.

This informal army is big business, responsible for an estimated 10 to 25 percent of the world’s cobalt production and about 17 to 40 percent of production in Congo. Artisanal miners alone are responsible for more cobalt than any nation other than Congo, ranking behind only Congo’s industrial mines.

The industry should be a boon for a country that the United Nations ranks among the least developed. But it hasn’t worked out that way.

“We are challenged by the paradox of having so many resource riches, but the population is very poor,” Muyej said.

Kolwezi is a remote city steeped in cobalt and copper, which are often found together. It is sometimes called the “Lungs of the Congo” because of its economic importance.

The city sits along a two-lane highway best known for carrying tractor-trailers laden with minerals as they hurtle for the border with Zambia 250 miles away.

Then it’s on to seaports in Tanzania or South Africa.

From there, most of the cobalt floats by ship to Asia, home to the vast majority of the world’s lithium-ion battery manufacturing.

About 90 percent of China’s cobalt originates in Congo, where Chinese firms dominate the mining industry.

The cobalt begins its journey at a mine such as Tilwezembe, a former industrial site turned artisanal operation on the outskirts of Kolwezi where hundreds of men scour the earth with hand tools.

These men call themselves “creuseurs,” French for “diggers.” They toil inside dozens of holes pockmarking the mine’s moonscape-like bottom. The tunnels are dug by hand and burrow deep underground, illuminated only by the toylike plastic lamps strapped to the miners’ heads.

During a visit in June, the scene looked preindustrial. Dozens of diggers were at work, but the only sound was the occasional muffled clink of metal on stone.

“We are suffering,” said one digger, Nathan Muyamba, 29. “And our suffering is for what?”

‘La fleur du cobalt’

0:00 / 2:25

Diggers don't have mining maps or exploratory drills.

Instead, they rely on intuition.

"You travel with the faith believing that one day you can find good production," said digger Andre Kabwita, 49.

Nature is said to be one guide. Yellow wildflowers are considered a sign of copper. A plant with tiny green flowers carries the telling name "la fleur du cobalt."

With few formal sites to claim for themselves, artisanal miners dig anywhere they can. Along roads. Under railroad tracks. In back yards. When a major cobalt deposit was discovered a few years ago in the dense neighborhood of Kasulo, diggers tunneled right through their homes' dirt floors, creating a labyrinth of underground caves.

Other diggers wait until dark to invade land owned by private mining companies, leading to deadly clashes with security guards and police.

The diggers are desperate, said Papy Nsenga, a digger and president of a fledgling diggers union.

Pay is based on what they find. No minerals, no money. And the money is meager — the equivalent of $2 to $3 on a good day, Nsenga said.

Diggers gather at the Tilwezembe cobalt mine outside Kolwezi. Miners make an average of $2 or $3 a day. A fistful of cobalt-laden dirt is held up at the Musompo mineral market, where diggers sell their cobalt at small shops known as "comptoirs."

"We shouldn't have to live like this," he said.

And when accidents occur, diggers are on their own.

Last year, after one digger's leg was crushed and another suffered a head wound in a mine collapse, Nsenga was left to raise the hundreds of dollars for treatment from other diggers. The companies that buy the minerals rarely help, Nsenga and other diggers said.

Deaths happen with regularity, too, diggers said. But only mass casualties seem to filter out to the scant local media, such as the U.N.-funded Radio Okapi. Thirteen cobalt miners were killed in September 2015 when a dirt tunnel collapsed in Mabaya, near the Zambia border. Two years ago, 16 diggers were killed by landslides in Kawama, followed months later by the deaths of 15 diggers in an underground fire in Kolwezi.

In Kolwezi, a provincial mine inspector frustrated by a recent run of accidents agreed to talk to The Post on the condition that he not be identified, because he was not permitted to talk to the media.

He met the journalists in a minibus — jumping in, closing the door and taking a seat in the middle, far from the tinted windows so no one on the street could see him.

That morning, he said, he had helped rescue four artisanal miners nearly overcome by fumes from an underground fire in Kolwezi. The day before, two men had died in a mining tunnel collapse, he said.

He said he had personally pulled 36 bodies from local artisanal mines in the past several years. The Post was not able to independently verify his claims, but they echoed stories from diggers about the frequency of mining accidents.

The inspector blamed companies such as Congo DongFang that buy the artisanal cobalt and ship it overseas.

"They don't care," he said. "To them, if you bring them minerals and you're sick or hurt, they don't care."

Congo DongFang responded that it had incorrectly assumed that these issues were the concern of its trading partners, who buy the cobalt from the miners and pass it on to the mining company.

Child labor

No one knows exactly how many children work in Congo's mining industry. UNICEF in 2012 estimated that 40,000 boys and girls do so in the country's south. A 2007 study funded by the U.S. Agency for International Development found 4,000 children worked at mining sites in Kolwezi alone.

Local government officials say they lack the resources to address the problem.

"We have a big challenge with the children, because it is difficult to take them out of the mines when there are no schools for these children to go to," said Muyej, the provincial governor. "We have to find a solution for this."

0:00 / 1:21

While officials and diggers acknowledge the problem of child labor, it remains a sensitive topic. Children work not just in underground mines, in violation of Congo's mining code, but also on the fringes of the cobalt trade.

Guards prevented Post journalists from visiting areas where, according to local diggers, children often can be found working. At one point, The Post saw a boy in a red sweatshirt struggling to carry a half-full sack of mineral rocks. Another boy in a black soccer jersey ran up to help. Kabwita, the digger, watched them.

"They are just 10 or 12," he said.

The Post also gave an iPhone to a digger to capture video of how women and children wash cobalt ores together.

One of these children is Delphin Mutela, a quiet boy who looks younger than his 13 years.

When he was about 8, his mother began taking Delphin with her on her trips to the river to clean cobalt ores. Washing minerals is a popular job for women here. At first, Delphin was tasked with keeping an eye on his siblings.

But he learned to distinguish the loose mineral pieces that fell into the water during washing.

Copper carried a hint of green.

Cobalt looked like dark chocolate.

If he could collect enough bits, he could get paid, maybe $1.

"The money I get I use to buy notebooks and so I can pay school fees," Delphin said.

His mother, Omba Kabwiza, said this is normal.

"There are many children there," she said. "That's how we live."

Skyrocketing demand

Cobalt is the most expensive raw material inside a lithium-ion battery.

That has long presented a challenge for the big battery suppliers — and their customers, the computer and carmakers. Engineers have tried for years to craft cobalt-free batteries. But the mineral best known as a blue pigment has a unique ability to boost battery performance.

The price of refined cobalt has fluctuated in the past year from $20,000 to $26,000 a ton.

Video: How lithium-ion batteries work

Lithium-ion batteries work much like other batteries — there's a positive electrode and a negative electrode, and the electrons move from one end to another, creating a charge. The difference is the materials inside, which make them lighter, longer-lasting and rechargeable.

Watch the video

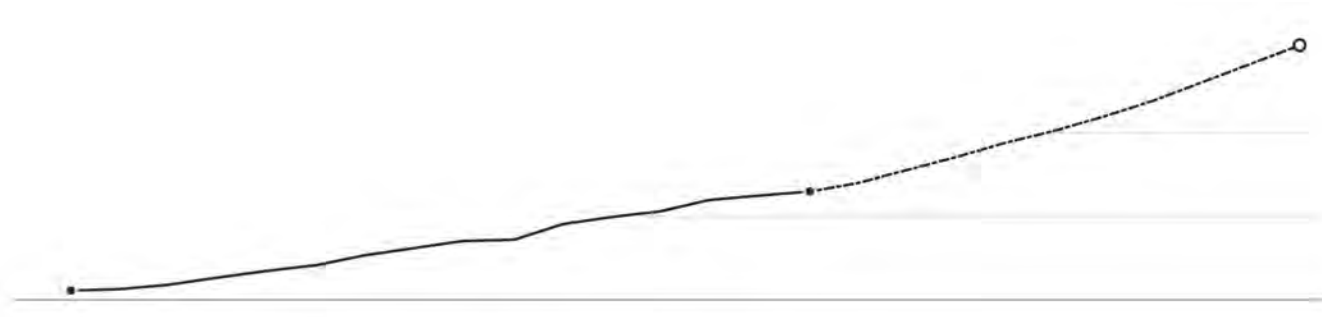
Worldwide, cobalt demand from the battery sector has tripled in the past five years and is projected to at least double again by 2020, according to Benchmark Mineral Intelligence.

This increase has mostly been driven by electric vehicles. Every major automaker is rushing to get its battery-powered car to market. Tesla's $5 billion battery factory in Nevada, known as the Gigafactory, is ramping up production. Daimler aims to open a second battery plant in Germany soon. LG Chem makes batteries for General Motors at a plant in Holland, Mich. Chinese company BYD is working on huge new battery plants in China and Brazil.

While a smartphone battery might contain five to 10 grams of refined cobalt, a single electric-car battery can contain up to 15,000 grams.

As demand has grown, so has artisanal cobalt's importance in global markets. That became clear to everyone in the battery world two years ago, said Kurt Vandeputte, vice president of the rechargeable-battery materials unit at Belgium-based Umicore, one of the world's largest cobalt refiners.

Cobalt demand for lithium-ion batteries is expected to double by 2025



76,525

75,000

tons

50,000

32,657

25,000

2,698

0

2000

2015

2025

Source: Christophe Pillot, Avicenne Energy

The cobalt price was falling, even as battery demand shot up. The price of lithium, another key battery material, was skyrocketing.

“It got so clear that artisanal mining was taking a big place in the supply chain,” Vandeputte said, adding that Umicore buys only from industrial mines, including mines in Congo.

Artisanal cobalt is usually cheaper than product from industrial mines. Companies do not have to pay miners’ salaries or fund the operations of a large-scale mine.

With cheap cobalt flooding the market, some international traders canceled contracts for industrial ores, opting to scoop up artisanal ones.

“Everyone knew something was going on,” said Christophe Pillot, a battery consultant at Avicenne Energy in France.

At the same time, companies face growing scrutiny of their supply chains.

Consumers demand accountability; companies respond with promises of “ethical sourcing” and “supply chain due diligence.”

One result of this increased scrutiny can be found in Congo.

In 2010, the United States passed a conflict-minerals law to stem the flow of money to Congo’s murderous militias, focusing on the artisanal mining of four minerals.

But this same diligence is not required when it comes to cobalt.

Children gather along the principal highway linking Kolwezi and Lubumbashi. Diggers wait to be paid at the Tilwezembe cobalt mine. The prices, based on weight and content, are written on a burlap sign. A digger gets ready to go into a mine shaft in Kawama. Residents stand outside of their homes in impoverished Kawama. Living conditions for miners and their families are harsh, with no electricity or running water.

While cobalt mining is not thought to be funding wars, many activists and some industry analysts say cobalt miners could benefit from the law’s protection from exploitation and human rights abuses. The law forces companies to attempt to trace their supply chains and opens up the entire route to inspection by independent auditors.

But while Congo is a minor supplier of the four designated conflict minerals, the world depends on Congo for cobalt.

Analyst Simon Moores at Benchmark said he thinks this is one reason that cobalt has so far been excluded.

Any crimp in the cobalt supply chain would devastate companies.

‘We sell this to the Chinese’

For most artisanal miners in Kolwezi, the global supply chain begins in a marketplace called Musompo.

The 70 or so small shops, known as “comptoirs,” are stacked cheek by jowl along the highway that leads to the border. Shop names are painted on cement walls: Maison Saha, Depot Grand Tony, Depot Sarah. Each shop has a handwritten board listing the going rate for cobalt and copper.

At a shop named Louis 14, the price list offered the equivalent of $881 for a ton of 16 percent cobalt rock. Rock with 3 percent cobalt was worth $55.

Nearby, minibuses pulled up with white sacks of freshly mined cobalt to sell. More sacks arrived on bicycles loaded down like pack animals.

Each load was tested by a radar-gun-like device called a Metorex, which detects mineral content. Some of the miners said they do not trust the machines, believing them to be rigged, but they have no alternative. Muyej, the governor, said he was looking for funds to buy a Metorex machine so diggers could independently test their minerals. There are many shops in Musompo, but diggers said the shops sold to the same company: Congo DongFang Mining.

“We sell this to the Chinese, and then the Chinese take it to CDM,” said Hubert Mukekwa, a shop worker shoveling cobalt.

An Asian man working at a “comptoir,” or counter, shop calculates a payment as “creuseurs,” or diggers, eagerly look on at the Musompo market.

In Congo, it is illegal for foreigners to own a comptoir. But not a single shop visited by Post journalists appeared to be run by Congolese. Asian men operated the Metorex machines. They punched up the tallies on oversize calculators. They handled the cash — thick wads of Congolese francs. And they often could be seen sitting in the back while Congolese men carried the 120-pound sacks. None of the comptoir bosses would talk to The Post.

Mukekwa finished filling up one sack.

“Once we have enough stock to take it to CDM,” he said, “we take it there.”

He pointed at a large blue-walled compound in the distance.

At a comptoir named Boss Wu, two Congolese workers, in jumpsuits with CDM printed in block letters on the back, stood watching other men loading cobalt sacks onto a truck.

Later, The Post witnessed an orange truck loaded with cobalt sacks pulling away from Musompo and onto the main highway.

“C24” was painted in blue on the truck’s cab. The Post followed C24 two miles up the highway, where it turned onto a dirt road running next to a tall brick wall. The truck continued on the road until it reached an entrance with armed guards and turned inside.

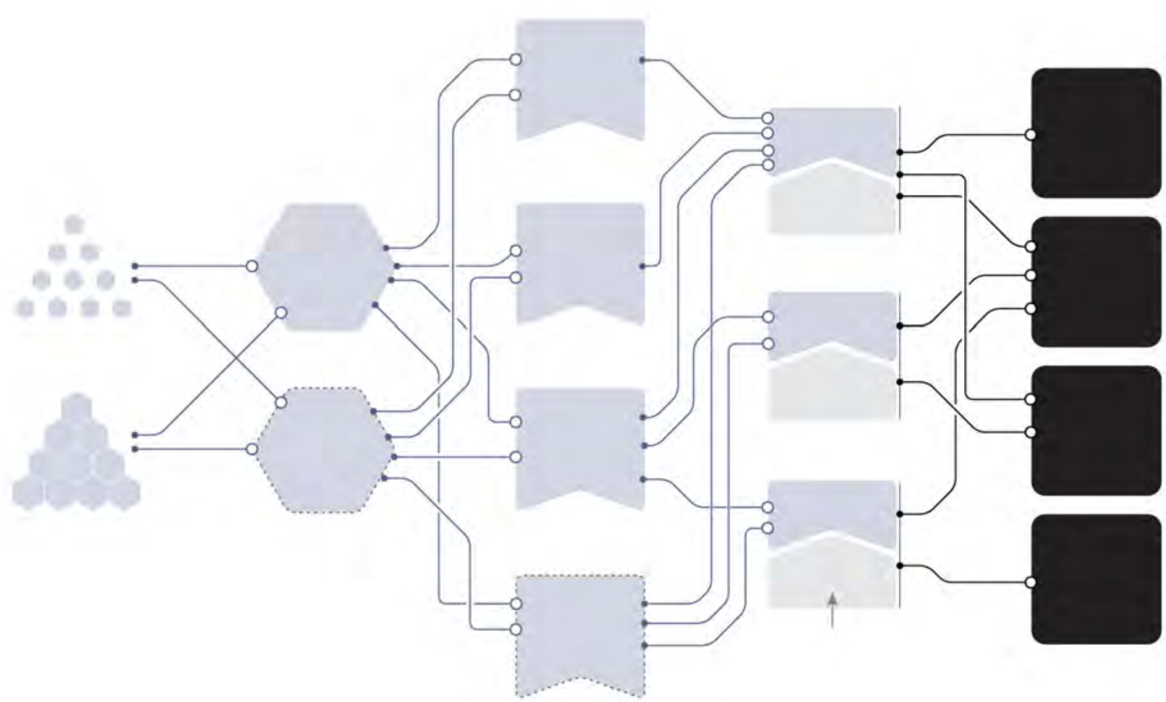
The facility with big blue walls was clearly marked CDM.

It was at these same gates that CDM says its inspection of its supply chain had stopped, never extending to the mines or marketplace, said Chen, the president of Huayou Cobalt, the parent company of CDM.

“We, in fact, didn’t know that much” about who they bought cobalt from, Chen said. “Now, we do due diligence.”

Tracing your battery’s cobalt

The lithium-ion battery industry has a massively complicated supply chain. Each consumer company has dealt with multiple suppliers — and their suppliers have dealt with multiple suppliers. This shows some of the connections within the industry. See companies' responses to Washington Post's investigation.



BATTERY MANUFACTURERS

CATHODE

MANUFACTURERS

They build batteries from cathodes, anodes and electrolyte solutions, all sourced from different companies.

Pulead

CONSUMER

PRODUCT

MAKERS

Amazon

THE COBALT

IS PROCESSED

They use the batteries in cellphones, laptops, tablets and electric vehicles.

ATL

COBALT IS MINED

CDM and

Huayou

Cobalt

Small-scale

mining

by hand

Shanshan

Apple

Samsung

SDI

Other

cobalt

processors

Samsung

L&F

Industrial

mines

LG Chem

LG

Other

cathode

makers

Cobalt is mined all over

the world, but 60 percent

comes from Congo.

Anodes come from

other manufacturers

Sources: Public documents, interviews with company officials and industry analysts.

What the companies say

Companies, in response to The Post's questions, sounded equally uncertain about their cobalt supply chain, illustrating how little is known about the sources of raw materials.

But expectations are different today, said Lara Smith of Johannesburg-based Core Consultants, a firm that helps mining companies with this problem.

“Companies can’t claim ignorance,” Smith said. “Because if they wanted to understand, they could understand. They don’t.”

Last year, CDM reported exporting 72,000 tons of industrial and artisanal cobalt from Congo, making it No. 3 on the list of the country’s largest mining companies, according to Congolese mining statistics.

And CDM is by far Congo’s top exporter of artisanal cobalt, according to analysts and the company.

CDM ships its cobalt to its parent company, Huayou, in China, where the ore is refined. Among Huayou’s largest customers are battery cathode makers Hunan Shanshan, Pulead Technology Industry and L&F Material, according to financial documents and interviews.

Company responses

The Washington Post asked consumer-product companies and battery makers about their cobalt supply chains. Here is what they said:

Congo DongFang Mining/Huayou Cobalt, Apple, LG Chem, LG, Ford, General Motors, Samsung SDI, Samsung, BMW, Amazon.com, Pulead L&F Material, Hunan Shanshan, Amperex Technology Limited (ATL)

These companies — which also buy refined minerals from other companies — make the cobalt-rich battery cathodes that play a critical role in lithium-ion batteries. These cathodes are sold to battery makers, including companies such as Amperex Technology Ltd. (ATL), Samsung SDI and LG Chem.

All of these battery makers supply Apple, providing power for iPhones, iPads and Macs.

Apple said its investigation revealed that its batteries from LG Chem and Samsung SDI contain cathodes from Umicore, which may contain cobalt from Congo but not from CDM. Apple said it thought its suspect cobalt was contained in ATL batteries with Pulead cathodes.

“I think the risks can be managed,” Pulead chief executive Yuan Gao told The Post, adding that he believes “the increased awareness is actually working, as everyone is monitoring everyone else along the supply chain.”

ATL also has supplied battery cells found in some Amazon Kindles, according to analysis by IHS, the global information company. ATL declined to comment.

Amazon.com, the company founded by Post owner Jeffrey P. Bezos, did not directly answer The Post’s questions about potential connections to suspect cobalt. The company issued a statement, reading in part: “We work closely with our suppliers to ensure they meet our standards, and conduct a number of audits every year to ensure our manufacturing partners are in compliance with our policies.”

More from this series

Graphite in China There’s a trace of graphite in many of today’s consumer devices. In these Chinese villages, it’s in their water, inside their homes and on their food.

Lithium in Argentina Indigenous people are left poor as tech world takes lithium from under their feet.

Samsung SDI, which supplies batteries for Samsung, Apple and automakers such as BMW, said that its own ongoing investigation “has not shown any presence” of suspect cobalt, although it does use cobalt from Congo.

Samsung, the phonemaker, provided The Post with a statement saying that it takes supply-chain issues seriously but not addressing a potential connection to CDM. Samsung buys batteries for its phones from Samsung SDI and ATL, among others, according to industry data.

BMW acknowledged that some of the cobalt in its Samsung SDI batteries comes from Congo but said The Post should ask Samsung SDI for more details.

LG Chem, the world’s largest supplier of electric-car batteries, said the company it buys cathodes from, L&F Material, stopped using Congo-sourced cobalt from Huayou last year. Instead, it said, Huayou now supplies L&F Material with cobalt mined from the South Pacific island of New Caledonia. As proof, LG Chem provided a “certificate of origin” for a cobalt shipment in December 2015 for 212 tons.

But two minerals analysts were skeptical that LG Chem’s cathode supplier could switch from Congo cobalt to minerals from New Caledonia — or, at least, do so for long. LG Chem consumes more cobalt than the entire nation of New Caledonia produces, according to analysts and publicly available data. L&F Material did not respond to repeated requests for comment. When The Post asked LG Chem to “respond to claims that the numbers don’t add up,” LG Chem did not answer the question directly, responding that it checks certificates of origin on a routine basis.

LG Chem also runs a Michigan battery plant for one of its biggest customers, GM, which plans to start selling its electric Chevrolet Bolt later this year. LG Chem said the Michigan plant has never received Congolese cobalt.

Another LG Chem customer, Ford Motor, said it has been told by LG Chem that Ford batteries have no history of CDM cobalt.

Most Tesla models use batteries from Panasonic, which buys cobalt from Southeast Asia and Congo. Replacement batteries for Tesla are manufactured by LG Chem. Tesla told The Post it knows LG Chem's Tesla batteries do not contain Congolese cobalt, but it did not say how it knows this.

Tesla, more than any other automaker, has staked its reputation on "ethically sourcing" every piece of its celebrated vehicles.

"It is something we do take very seriously," Kurt Kelty, Tesla's director of battery technology, said in March at a battery conference in Fort Lauderdale, Fla. "And we need to take it even more seriously. So we are going to send one of our guys there."

Six months later, Tesla told The Post it is still working on sending someone to Congo.

Birth defects, illness

In Lubumbashi, another center of Congo's mining industry, 180 miles from Kolwezi, doctors have begun to unravel what has long been a mystery behind a range of health problems for local residents.

Their findings point to the mining industry as the problem.

These doctors at the University of Lubumbashi already know miners and residents are exposed to metals at levels many times higher than what is considered safe.

One of their studies found residents who live near mines or smelters in southern Congo had urinary concentrations of cobalt that were 43 times as high as that of a control group, lead levels five times as high, and cadmium and uranium levels four times as high. The levels were even higher in children.

Another study, published earlier this year, found elevated levels of metals in the mining region's fish. A study of soil samples around mine-heavy Lubumbashi concluded the area was "among the ten most polluted areas in the world."

Now the doctors are working to connect the dots.

"We are trying to draw a line between disease and metals," said Eddy Mbuyu, a university chemist.

But they are cautious about their task.

"The mining business has the money, and that money means power," said Tony Kayembe, an epidemiologist at the university's hospital.

Current studies are looking at thyroid conditions and breathing problems. But doctors are most concerned by possible connections to birth defects. One study the university doctors published in 2012 found preliminary evidence of an increased risk of a baby being born with a visible birth defect if the father worked in Congo's mining industry.

The Lubumbashi doctors also have issued reports on birth defects so rare — one is called Mermaid syndrome — that they are the only cases ever known in Congo. All occurred in children born in heavy mining regions.

For Kayembe, the study that stood out most looked at babies born with holoprosencephaly, a usually fatal condition that causes severe, distinctive facial deformities. It is almost unheard of. Entire medical careers pass without seeing one. But last year, doctors in Lubumbashi recorded three cases in three months.

"This is not normal," Kayembe said.

These medical inquiries could bring some relief to residents such as Aimerance Masengo, 15, who has been blaming herself since giving birth last year to a baby boy with severe, fatal birth defects.

In a voice barely above a whisper, Aimerance recalled how she had been so scared when she saw her newborn. The doctor was scared, too, she said.

The doctor told Aimerance it was impossible to know for certain what went wrong. But, he noted, the baby's father worked as a cobalt digger. He told Aimerance he had seen many problems in the children born to diggers.

Aimerance and the baby's father lived in the nearby village of Luiswishi, home to 8,000 people. Everyone there seemed to be connected to artisanal mining. And in the past three years, according to local activists, four newborns from this tiny village have died of severe birth defects.

A child throws a stone into the Kapolowe River outside Lubumbashi. Environmentalists, doctors and activists say that the region's rivers suffer from severe pollution that they think is from the copper and cobalt mining throughout the area. Catfish caught in the Kapolowe River is offered to prospective customers near the river's banks. A study published this year showed elevated levels of metals in the mining region's fish. A digger works at the mine in Kawama. Most of the work is done with manual tools and with virtually no environmental or safety precautions. Diggers wait for their pay at the Musompo market.

The ‘creuseurs’ wait

For diggers such as Sidiki Mayamba, worried about affording flour for his family, the greatest concern is not safety or potential health problems. It is money. He needs the work. But he doesn’t want his 2-year-old son, Harold, to follow him into the mines.

“A digger is a hard job with many risks,” Mayamba said. “I cannot wish for my child to have this kind of job.”

Cleaning up the cobalt supply chain will not be easy for Huayou Cobalt, even with the support of a powerful company such as Apple.

But Chen, Huayou’s president, said it is the proper action, not only for the company but also for the Congolese miners.

“Some companies just want to get away from the problem,” Chen said. “But Congo’s problem is still there. The poverty is still there.”

The question is whether Huayou’s other customers, after years of buying cheap cobalt with no questions, will be supportive.

Pyers, the Apple senior director, said the company does not want to take steps aimed at just “making the supply chain look pretty.”

“If we all cut and run from the Democratic Republic of Congo, it would leave the Congolese people in a devastating position,” Pyers said. “And we will not be a party to that here.”

Starting next year, Apple will internally treat cobalt like a conflict mineral, requiring all cobalt refiners to agree to outside supply-chain audits and conduct risk assessments.

Apple’s action could have major repercussions throughout the battery world. But change will be slow. Apple spent five years working to certify that its supply chain was free of conflict minerals — and that action was enforced by law.

None of these efforts change the fate of diggers such as Kandolo Mboma.

At the Tilwezembe mine this summer, Mboma sat on a boulder, seemingly catatonic, his blue jeans stained black, his bare feet dangling just above the red dirt. His eyes failed to register the other diggers filing past.

“He was working all night, and he has not eaten,” a fellow digger said.

Mboma, 35 and a father of three, was waiting for his cobalt to be weighed. Then, he hoped, he would get paid.

He sat next to a series of small food stalls, stout squares of discarded mining sacks stretched over sticks, where a digger could buy a bread roll for 100 Congolese francs, equal to about 10 cents. The bread came with a free cup of water.

“You eat what you make,” Mboma said finally.

And eating would have to wait.

A “creuseur” descends into a tunnel at the mine in Kawama. The tunnels are dug with hand tools and burrow deep underground.

Peter Whoriskey in Washington contributed to this report.

More stories

Companies respond to questions about their cobalt supply chains

As part of the investigation, The Washington Post asked consumer-product companies and battery makers about their cobalt supply chains. See what they had to say.

The batteries in your favorite devices are literally covering Chinese villages in black soot

There’s a trace of graphite in many of today’s consumer devices. In these Chinese villages near the factories that produce it, it’s everywhere — in their water, inside their homes and on their food.

Companies are making billions in lithium mining. But these indigenous people are being left out.

Hunt for the mineral known as ‘white gold’ intensifies in the Andes, but those who live on the land say they are being tossed aside.

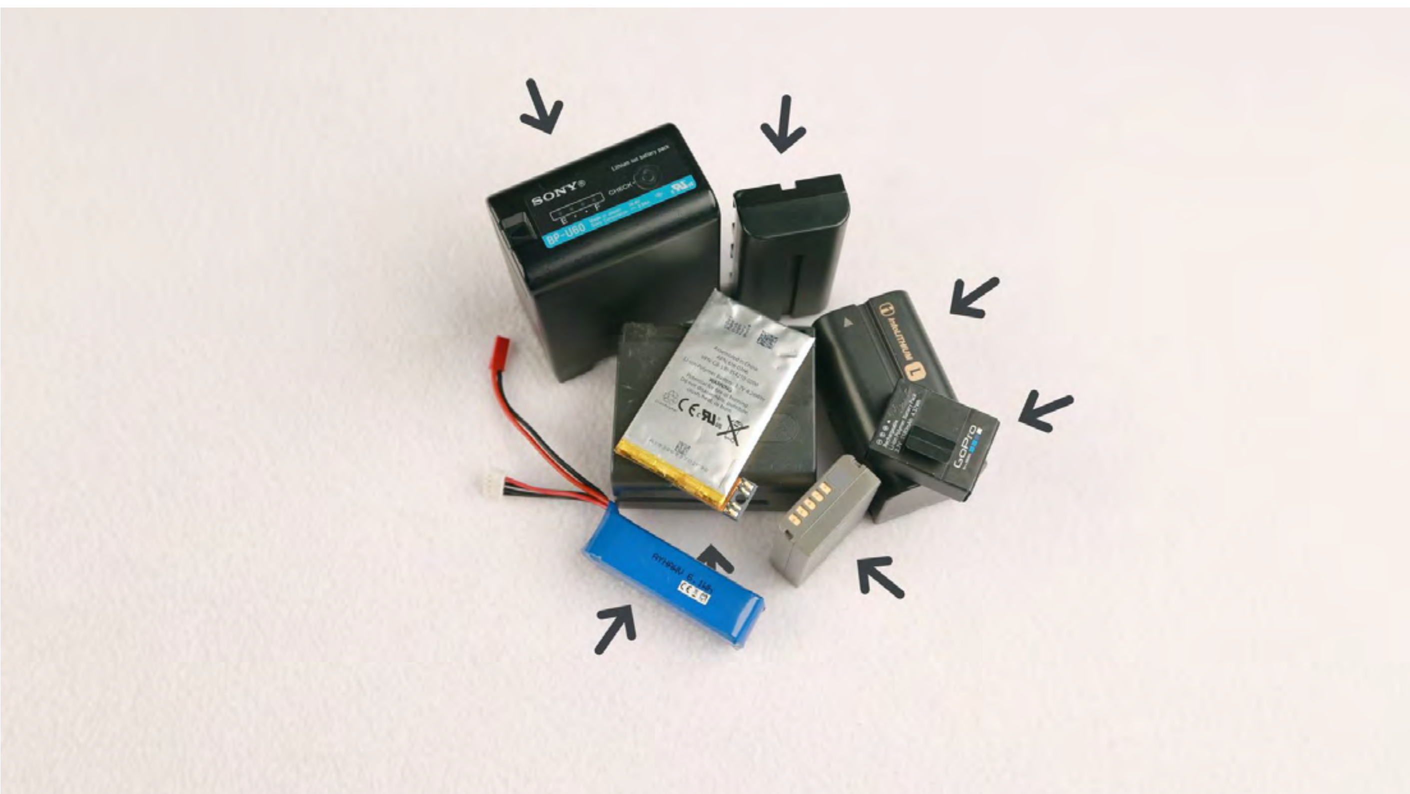
How a lithium-ion battery works

Lithium-ion batteries work much like other batteries — there’s a positive electrode and a negative electrode, and the electrons move from one end to another, creating a charge. The difference is the materials inside, which make them lighter, longer-lasting and rechargeable.


The Washington Post


MOBILE POWER,
HUMAN TOLL
IN YOUR
PHONE, IN
THEIR AIR


MOBILE POWER,
HUMAN TOLL
TOSSED
ASIDE
IN THE
'WHITE GOLD' RUSH


SONY
BP-U60
GoPro

August 19, 2020

Governor Gavin Newsom

1303 10th Street, Suite 1173

Sacramento, CA 95814

Dear Governor Newsom,

We write in response to your letter from earlier this week regarding the power outages of August 14 and 15 that were triggered due to insufficient resources.

We agree that the power outages experienced by Californians this week are unacceptable and unbefitting of our state and the people we serve. We understand the critical importance of providing reliable energy to Californians at all times, but especially now, as the state faces a prolonged heat wave and continues to deal with impacts from the COVID-19 pandemic.

Californians have always responded to great disruptions with courage, determination, and creativity. This week was no exception. But it is unfair to make Californians endure disruptions that are within our reach to avoid. We, as individuals, and the organizations we lead, share in the responsibility for what many Californians unnecessarily endured. We also share in the commitment to pinpoint the causes and ensure they do not reoccur.

Your letter requests that our organizations provide information to understand the causes of the recent supply deficiencies and the actions that can be taken in the near and longer-terms to minimize power outages. These questions deserve a more thorough review and response from us in the coming days, but in the sections below we provide responses based on the information we have now.

Near-Term Energy Demand Forecast

In the near term, the California Independent System Operator (CAISO) expects that energy demand will remain high as the current heat wave persists. In the table below, the CAISO provides its most recent demand forecasts for August 20 through 24. The table shows forecasted demand for two times of the day when the demand on the grid peaks. The first is the peak load hour, which occurs from 5 to 6pm (peak load hour) and the second is when the demand on the system, net of expected wind and solar production, occurs which is from 7 to 8pm (net load peak hour) for each day:

Table 1: Short Term Demand Forecasts

Forecast Period	8/20	8/21	8/22	8/23	8/24
Peak Load Hour Demand	45,113	44,743	42,718	42,154	46,779
Net Load Peak Hour Demand	42,850	42,415	41,393	40,946	44,329

The CAISO estimates that August resource adequacy capacity provides approximately 46,000 megawatts (MW) of load carrying capability at the peak load hour, after considering estimated outages. This load carrying capability drops to approximately 43,000 MW during the net load peak hour. Based on these forecasts, there is currently a risk of resource insufficiency on Monday, August 24. If those projections materialize as forecasted, the CAISO will require economic import energy to meet system needs. If economic import energy is unavailable, it could lead to additional supply shortages. The CAISO will do everything it can to avoid service interruptions. As detailed later in this letter, significant efforts have been undertaken across the state in recent days to reduce demand and identify additional supply.

Lack of Advance Warnings for Supply Deficiencies

As the CAISO anticipated high loads and temperatures beginning on August 14, it issued an order restricting maintenance operations on August 12, an alert identifying a possible system reserve deficiency on August 13, and a Flex Alert for August 14. However, the situation deteriorated on the afternoon of August 14, with the unanticipated loss of supply and severe constraints on imports because of a developing, historic west-wide heat wave. The imbalance in supply and demand led to the need to order the utilities to turn off power to their customers later that evening. On August 15, the CAISO experienced similar supply conditions, as well as significant swings in wind resource output when evening demand was increasing. Wind resources first quickly increased output during the 4:00 pm hour (approximately 1,000 MW), then decreased rapidly the next hour. These factors, combined with another unexpected loss of generating resources, led to a sudden need to shed load to maintain system reliability. The combination of high system demand, unanticipated loss of supply, and low net import availability due to hot temperatures throughout the West created untenable system conditions. Although the CAISO could not have predicted the specific series of events that ultimately required power outages, better communications and advance warnings about tight supply conditions were possible, and should have been done. The CAISO is committed to improving its communications, and providing appropriate warnings of such circumstances.

Causes of Recent Supply Deficiencies

We are working closely as joint energy organizations to understand exactly why these events occurred. The grid conditions of August 14 and 15, with peak demands of approximately 47,000 MW and 45,000 MW respectively, were high but not above similar hot days in prior years. Given this, our organizations will need to conduct a deep dive into how we ensure sufficient electric supply, and will make modifications to our reliability rules to make sure reliability resources can be available to address unexpected grid conditions.

Assigning definite causes to events on the electricity grid requires careful analysis, which will take time, however, we do know a number of things already. We know that capacity shortfalls played a major role in the CAISO's ability to maintain reliable service on the grid. A major focus of our review will need to be on the joint organizations' process of determining the needed capacity.

The resource adequacy procurement requirements are set by the California Public Utilities Commission (CPUC), to be based on a 1-in-2 peak forecast, *i.e.*, an average year forecast. This forecast is developed by the California Energy Commission (CEC) based on an agreed-upon methodology between the CEC, the CPUC, and the CAISO. To account for contingencies such as outages, import variability, load forecast error, and reserve requirements, the program requires utilities to procure a 15% planning reserve margin above the monthly peak load forecast. The rules take into account the fact that the grid needs both a sufficient quantity and quality of resources to meet demand. As the events of the past few days indicate, a review of how the organizations forecast hourly demand and set reserve margins is critical. The forecasts and planning reserves need to better account for the fact that climate change will mean more heat storms and more volatile imports, and that our changing electricity system may need larger reserves.

Another factor that appears to have contributed to resource shortages is California's heavy reliance on import resources to meet increasing energy needs in the late afternoon and evening hours during summer. Some of these import resources bid into the CAISO energy markets but are not secured by long-term contracts. This poses a risk if import resources become unavailable when there are West-wide shortages due to an extreme heat event, such as the one we are currently experiencing. The CAISO has observed that during the current heat wave, energy supporting imports from other Western utilities have been significantly constrained during the late afternoon and evening hours, as those other utilities must plan to meet their own demand and have limited ability to export supplies to California. This hampers the CAISO's ability to secure net import energy sufficient to meet evening ramping requirements.

After this heat wave passes, as directed in your letter, our organizations will perform a root cause analysis of the events of August 14 and the following days, to understand the cause of the resource shortfalls. The CAISO will collaborate with the CPUC and the CEC on this analysis, and to promote long-term action to avoid these types of events in the future.

Collectively, our organizations want to be clear about one factor that did not cause the rotating outage: California's commitment to clean energy. Renewable energy did not cause the rotating outages. Our organizations understand the impacts wind and solar have on the grid. We have already taken many steps to integrate these resources, but we clearly need to do more. Clean energy and reliable energy are not contradictory goals.

Our collective investigation will include, at a minimum, a review of the following:

- Resource sufficiency, including:
    - Level of resource adequacy requirements relative to grid loads and grid conditions,
    - Imports and exports and their impact on reliability during periods of system stress conditions,
    - Outages, derates, and resource performance during system stress hours,
    - Performance of resources supplied to grid operator by CPUC and non-CPUC jurisdictional entities,
    - Availability of CAISO import capability to CPUC jurisdictional entities;
- Transmission grid performance, including outages and availability constraints;
- Sufficiency of existing incentives and penalty structure for deterring non-performance of reliability resources;
- Demand forecasts and how they are utilized in resource planning;
- Review of interagency coordination on summer reliability planning and assessment;
- Challenges to contracting for the retention of gas fleet resources needed for reliability; and
- Market performance observations and opportunities.

Immediate Actions to Address this Week's Supply Deficiencies

Since August 14, a number of immediate actions have been taken to minimize disruption and increase reliability. A collective effort, led by you and your staff, created a massive statewide mobilization to conserve electricity and maximize existing generation resources. The efforts led to reductions in peak demand on Monday and Tuesday of nearly 4,000 MW and an addition of nearly 950 MW of available temporary generation.

Some specific examples of actions that were taken include:

Demand Side Conservation Actions

- The CAISO called on demand response programs and other available demand relief;
- The CPUC issued a letter on Monday, August 17th, clarifying use of back-up generators in connection with specific demand response programs is allowable, which resulted in at least 50 MW of additional demand reduction each day;
- Solar and storage companies, including Sunrun and Tesla, worked with their customers to change battery charging patterns so that they are maximizing effectiveness between 4 and 9pm;
- The CEC coordinated with data center customers of Silicon Valley Power to move approximately 100 MW of load to backup generation facilities onsite;
- The CEC coordinated with the US Navy and Marine Corps to disconnect 22 ships from shore power, move a submarine base to backup generators, and activate several microgrid facilities resulting in approximately 23.5 MW of load reduction; and
- Six Electric Program Investment Charge (EPIC)-funded microgrids reduced load by a total of approximately 1.2 MW each day.

Supply Side Resources Actions[1]

- The CAISO procured available emergency energy;
- The CAISO executed significant event Capacity Procurement Mechanism to procure additional supply resources;
- The CAISO Suspended a market feature to ensure physical certainty of solution;
- Department of Water Resources (DWR) and Metropolitan Water District (MWD) adjusted water operations to shift 80 MW of electricity generation to the peak period;
- DWR and the U.S. Bureau of Reclamation (USBR) shifted on-peak pumping load that resulted in 72 MW of load flexibility;
- The CEC worked with the City and County of San Francisco to maximize power output at Hetch Hetchy which allowed for an additional 150 MW during the peak period;
- The CEC worked with private power producers to contribute an additional 147 MW from the following sources: SEGS Solar Plant: 60 MW, Ivanpah Solar Power Plant: 42 MW, and Sentinel: 45 MW;
- PG&E deployed temporary generation, that was procured for public safety power shutoff purposes, across its service territory totaling approximately 60 MW;
- SCE worked with generators to ensure that additional capacity was made available to the system from facilities with gas onsite or through invertor changes; and

[1] The additional capacity highlighted in this section is part of the 950 MW of available temporary generation, but does not comprise the totality of the 950 MW.

- LADWP helped bring additional generation from Haynes 1 and Scattergood power plants totaling 300 to 600 MW

Conservation Messaging Actions

- The CAISO Issued Flex Alerts and warnings;
- The CAISO, CEC and CPUC supported the Governor's Office and the California Governor's Office of Emergency Services to publicly request electricity customers lower energy use during the most critical time of the day, 3:00 pm to 10:00 pm;
- The CPUC issued a letter to the investor owned utilities on August 16 requesting that they aggressively pursue conservation messaging and advertising, and requested Community Choice Aggregators do the same; and
- The CPUC redirected the Energy Upgrade California marketing campaign messaging and media outreach to focus on conservation messaging.

With these efforts, we hope to reduce or prevent immediate future outages to the greatest extent possible.

Going-Forward Actions to Ensure Reliability

Our organizations are committed to collaborating on longer-term solutions and to re-examining our forecasts and existing reliability policies and programs to avoid future supply shortfalls.

The CEC will continue to refine its demand forecast, which currently accounts for climate change, based on improving science and stakeholder engagement, and will expand its demand forecasting process to include a broader set of scenarios that capture extreme weather events and associated load impacts. New peak demand forecasts could be used in the CPUC's resource adequacy program, which currently requires a 1-in-2 peak forecast. In addition, the CEC will:

- Develop an aggregate statewide view of resource adequacy obligations and available resources serving those obligations.
- Continue work to enable distributed energy resources and load flexibility, including development of load management standards to support grid reliability.

The CAISO will review its assumptions regarding solar power and other sources of energy to ensure its assumptions of available capacity are accurate.

The CPUC will review its resource adequacy requirements, existing procurement plans and demand response programs. The results of the root cause analysis will better help to strengthen and inform this reassessment. Some of the work that will contribute to the holistic reassessment you request has already been initiated.

- In 2019, the CPUC tightened electricity import rules to ensure imports and all other resources the state relies on are actually delivered to California on peak days.
- The CPUC ordered 3,300 MW of new capacity to come online by 2023 to meet potential shortfalls that were identified when it adjusted assumptions to reflect that peak demand occurs later in the day.
- The CPUC opened a phase in its Resource Adequacy proceeding to consider changing the framework for determining reliability rules. These changes may be needed to adjust for the fact that community choice aggregators dominate the retail electricity market.

Beyond that, the CPUC will work to ensure that increasingly prevalent distributed resources can be efficiently activated to support the grid even if they do not qualify to provide reliability services.

With regard to your request to review the mix of imports and in-state generation, our organizations agree that further attention is required to ensure that these resources are available when needed. As discussed above, the CPUC has already taken action to make imported electricity more dependable, and has also reduced the planning assumption for how much imported electricity will be available into California. The changes in those assumptions resulted in the directive to build 3,300 MW of new resources that will start coming online in 2021.

Each of our organizations has more work to do in order to be fully responsive to your letter and to ensure that we are taking every measure necessary to guarantee the events of this past week will not be repeated. We thank you for your leadership and will each be sending you individual follow on letters that will address the questions and directives in your letter in more depth.

Sincerely,

Marybel Batjer

President

California Public Utilities Commission

Stephen Berberich

President and Chief Executive Officer

California Independent System Operator

David Hochschild

Chair

California Energy Commission

Informing the **Transmission Discussion**

A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States

January 2020

scottmadden MANAGEMENT CONSULTANTS

WIRES

Executive Summary

Contents

Objectives of This Study

- Much has been written discussing the role of and need for transmission for integration of renewables and grid resiliency issues in the wake of heightened cybersecurity awareness (given global geopolitics) and other natural events (e.g., superstorms and hurricanes, bomb cyclones, extreme cold snaps, and wildfires).
- Many examinations of these topics have been conceptual, addressing policy issues with broad recommendations. Other treatments have been more technical, looking at specific physical insufficiencies in infrastructure.
- The challenge of these issues, and previous discussions of them, is the desire for a "universal solvent" that will remedy transmission infrastructure gaps across the nation; however, many of these issues are inherently regional. Each location has its endowment of existing infrastructure (including power generation and transmission), load sinks, renewable resource potential, and potential risks from widespread resilience events. Moreover, states have a meaningful role in siting and permitting electric facilities, mandating renewables procurement, and cost recovery. Indeed, different states are forcing the issue on renewables integration as they announce aggressive clean energy standards.
- This study focuses, region-by-region, on the key issues of renewables integration and resilience challenges. It reviews the current transmission landscape, renewable integration issues, recent resilience concerns, what regional transmission planners have done to address these, and what they believe ought to be done going forward to ensure reliability and resilient accommodation of growing amounts of renewable resources.
- It also examines some of the interregional needs and barriers to transmission development, summarizing key interregional issues in integrating renewables, identifying how regional organizations and others are dealing with these issues, and gleaning any lessons learned.

The goal of this study is to inform policymakers and the public of region-specific needs, issues, and challenges including the integration of location-constrained renewable resources and resilience. This review is done with a view of where and how transmission can and should play a role in addressing these needs.

Industry Backdrop

The electric industry has undergone a tremendous amount of growth and change over the past two decades, and it continues to evolve as policy and customer preferences, improving technology costs, and increasing focus on reducing greenhouse gas emissions (GHG) drive shifts in energy resources and consumption patterns. This transformation is driven by four key developments:

Changing Energy Mix	Deployment of Distributed Energy Resources (DERs) and Energy Storage	Aspirations for Beneficial Electrification	Strong Interest in Renewable and Greenhouse Gas Emissions-Free Resources
▪ Abundant and inexpensive natural gas making gas-fired power generation attractive ▪ Continued retirement of conventional fossil power plants nearer to load, as well as some nuclear plants ▪ Growing amounts of utility-scale wind and solar generation being proposed, but highly location-specific	▪ Growth in smaller DERs on the distribution system, both behind-the-meter and in larger-scale applications like microgrids, spurred by policy support and declining costs, and subject to favorable benefit-cost analysis ▪ Potential for support of local reliability and resilience ▪ However, lack of visibility and control, and uncertain impacts on demand behavior	▪ Customer, select policy interest in “deep decarbonization” and utility interest in increasing system load ▪ Electric industry and stakeholders looking at beneficial electrification to displace some traditional non-electric applications (e.g., light- and heavy-duty vehicles, space heating) ▪ GHG emissions “exchange” with electrification highly dependent upon power supply fuel mix	▪ Renewable portfolio standards (RPS), in place for years, increasing in scale ▪ States announcing ambitious clean energy (i.e., non-GHG-emitting energy resources) goals ▪ Large corporate buyers looking for renewable energy supply for national and global operations, for value and brand equity ▪ Latest trend: clean energy and net-zero emissions targets announced by some electric utilities

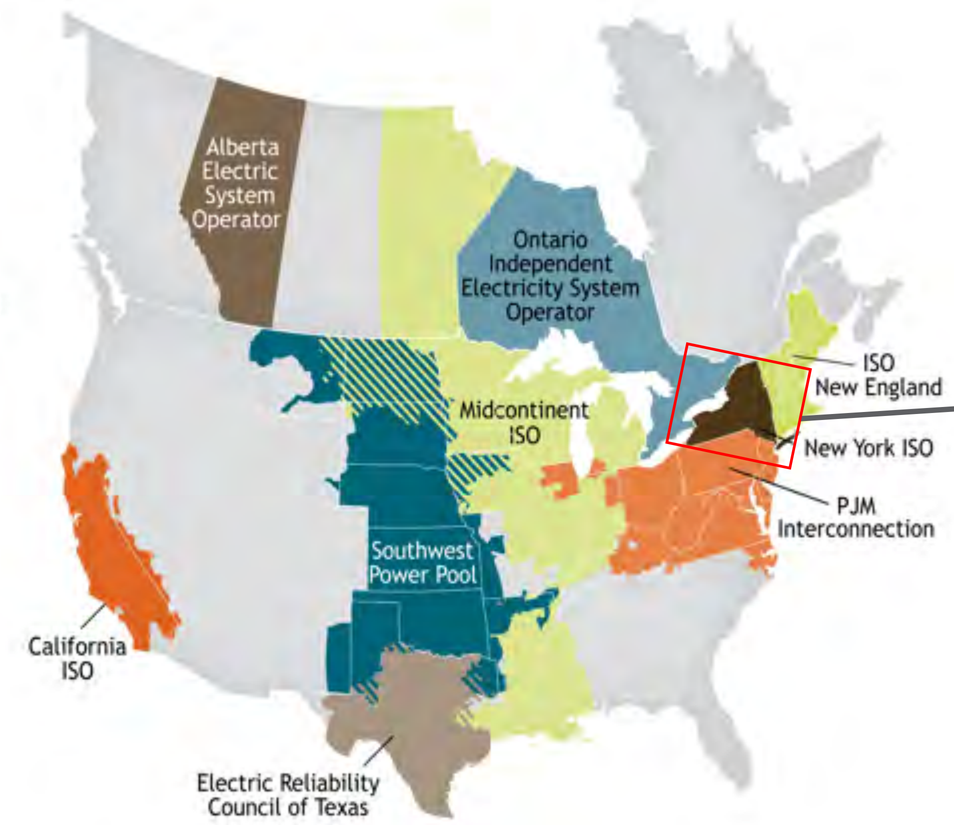
The developments noted above warrant consideration of impacts on the bulk power system and transmission in particular.

Regional Transmission Summary – ISO-New England

ISO-New England

- Ambitious clean energy goals in all six states: Ranging from 25.2% by 2025 in New Hampshire at the low end to 100% by 2050 in Maine at the high end, with demand expected to exceed supply in 2030, opening opportunity for more imports from Canada.
- Large offshore wind development target requires related offshore grid build-out, and onshore wind development in Northern Maine requires capacity to move wind to load
- Retiring nuclear and other thermal generation and significant reliance on natural gas generation creates fuel and energy availability risk.
- Resilience concerns, including extreme cold weather gas constraints for generation fuel, opens possible need for increased capacity at interfaces – "gas by wire" from PJM (via NYISO), hydropower from Canada (Quebec, in particular).

Regional Transmission Summary – New York ISO



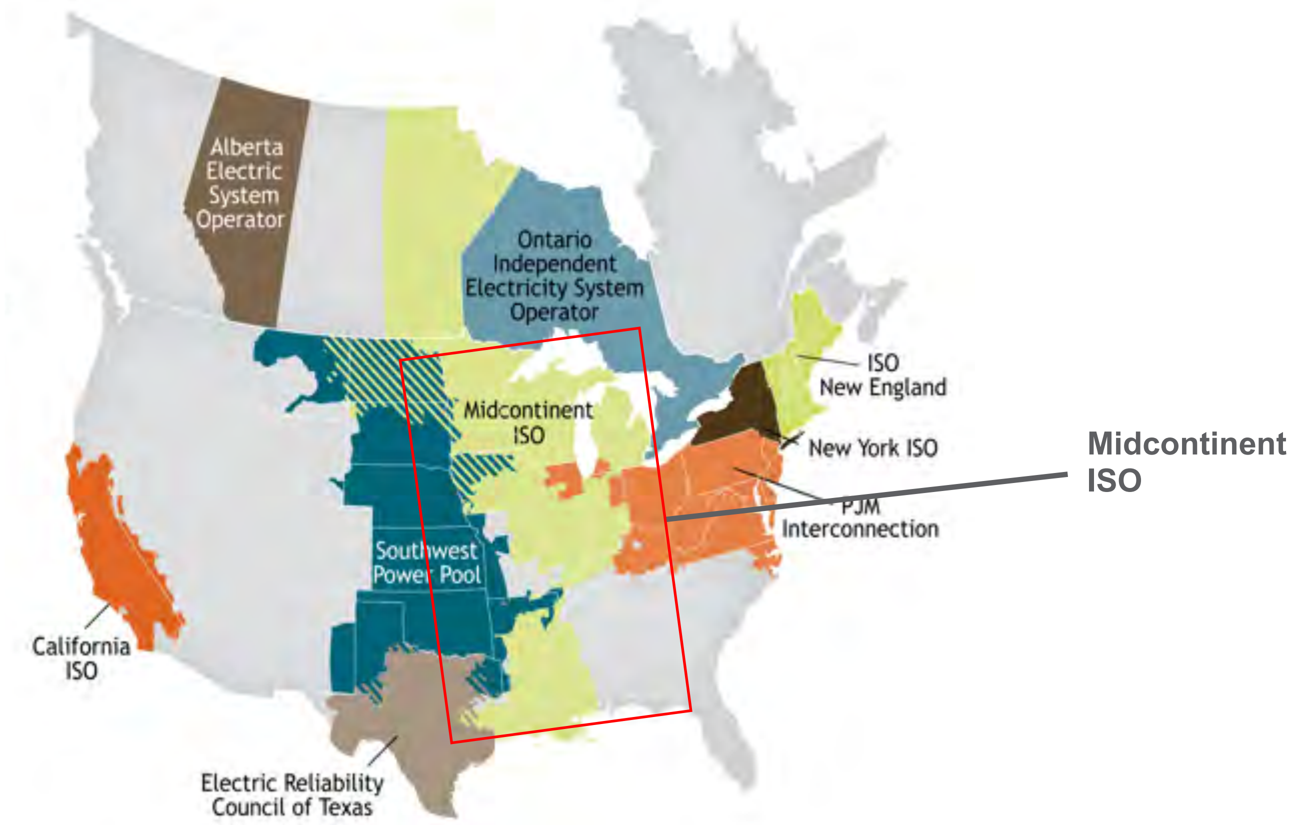
New York ISO

- Ambitious clean energy goals: 70% by 2040 and possibly inadequate in-state renewables supply opens opportunity for imports from Canada, west.
- Large offshore wind development target requires related offshore grid build-out.
- Ongoing “de-bottlenecking” of upstate renewables for deliverability to downstate load centers.
- Retiring nuclear and other thermal generation and significant reliance on natural gas generation downstate creates fuel and energy availability risk.
- Resilience concerns, including extreme cold weather gas constraints for generation fuel, opens possible need for increased transmission capacity at interfaces – “gas by wire” from PJM, hydropower from Canada.

Regional Transmission Summary – PJM Interconnection

- Disparate clean energy goals among the states within the region has led to a contentious capacity market ruling by Federal Energy Regulatory Commission (FERC), issued in December 2019 and likely to generate more debate when PJM makes it compliance filing.
- New wind and gas generation development has driven interconnection needs in recent years, but new solar represents the majority of capacity currently in the queue.
- More renewable resources than policy demand in region, and more gas capacity than needed; opportunity for export.
- Transmission investment has trended toward more local and lower voltage “Supplemental Projects” recently, driven by asset performance, condition, and risk, as congestion in the region has been reduced.
- Retiring nuclear and other thermal generation and significant reliance on natural gas generation creates fuel and energy availability risk.
- Resilience concerns, including extreme cold weather gas constraints for generation fuel, opens possible need for increased capacity at interfaces with MISO and NYISO.
- Complications to expansion in region: Public policy differences among states, low to negative load growth expectation for the planning horizon.

Regional Transmission Summary – Midcontinent ISO



- Diverse region with three distinct areas: wind-heavy west; thermal baseload-heavy central (with growing retirements); and gas-fired generation-heavy south.
- While wind development, especially in the west northwest of region is a big part of resource development, increasing amount of solar across region, potentially creating some different and more localized transmission needs.
- Significantly more renewable resources than policy demand in region; opportunity for export.
- Potential for targeted transmission needs in Midcontinent ISO (MISO) West as region contemplates potential for long-term “tipping point” of 30% to 40% wind penetration.
- Reducing congestion has been a goal, and multi-value projects completed since 2011 have lowered congestion and allowed for lower marginal cost wind greater market access and has removed need for $300M in baseline reliability upgrades.
- Market-to-market payments indicate potential for east-west interregional enhanced transfer capability with PJM and load centers to the east.
- Resilience challenges different within region, largely seasonal extreme weather; potential for transmission capacity between north and south to diversify resources, energy transfers during times of system stress.
- Potential for expansion of transfer capacity on north-south constraint between MISO North/Central and MISO South – off-peak wind moving south, low cost gas, solar power moving north.
- Complications to expansion in region: 2015 settlement agreement upon addition of MISO South; public policy differences between MISO South states and MISO North/Central states.

Regional Transmission Summary – Southeast

- Vertically integrated, rate-of-return market area, with generation and transmission considered mostly using traditional integrated resource planning – transmission “built to suit.”
- Growing renewable resources in region (especially utility-scale solar), more than policy-generated demand in region, but still small in comparison to thermal resources, including growing gas-fired and new nuclear generation units.
- Long-term potential for offshore wind, but limited activity to date.
- Limited renewable integration issues to date; region is now studying potential impacts, including effect of increased solar in increasingly winter-peaking region.
- Some resilience challenges driven by tropical cyclones and ice storms; opportunity for grid hardening.
- Increasingly winter-peaking with exposure to extreme cold weather (cold snaps); increased gas dependence raises issues around single point of disruption (pipeline interruption or reduced gas availability).

Regional Transmission Summary – Southwest Power Pool

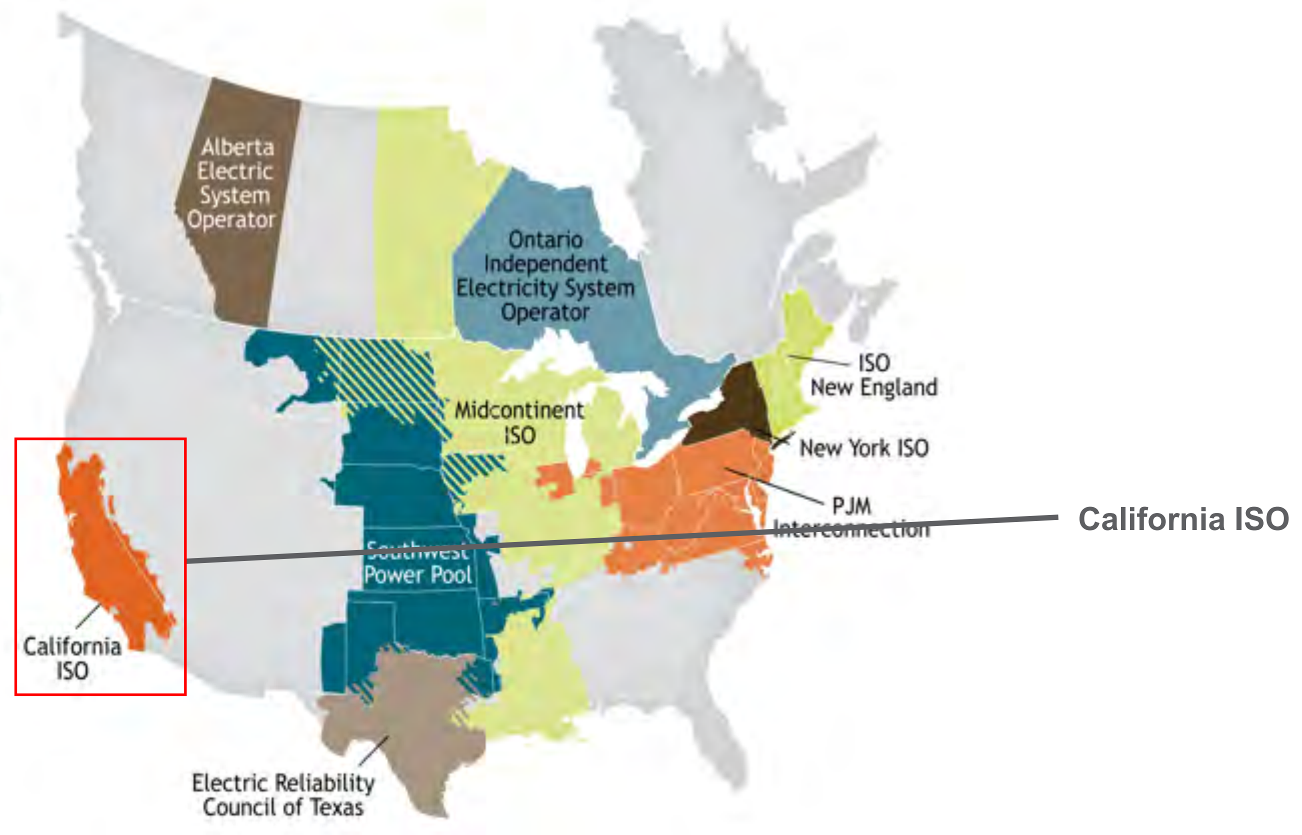
- "Tale of two grids" with high wind penetration in north and west approaching levels that typically cause integration issues, with population centers south and east.
- Large wind potential in region, in north and south, with large (51 GWs) interconnection queue, with growing interest in solar (28+ GWs in queue) in south.
- Significantly more renewable resources than policy demand in region; opportunity for export.
- The region has developed a high-voltage backbone, which has been well-utilized as renewable resources have come online.
- Potential west-to-east transmission for relief of "pinch points" in central Kansas/southwest Missouri to accommodate northeast-to-southwest Southwest Power Pool (SPP) flows.
- Potential for increased integration with Western Interconnection for broader footprint for renewable resource optimization; being tested with SPP's Western Energy Imbalance Service and reliability coordinator role.
- Potential for increased integration with MISO for west-to-east flows of increasing wind and solar resources to load centers, resilience support.

Regional Transmission Summary – Western U.S. (Excl. California ISO)

- Diverse and expansive region with varying climate and weather patterns, including access to some of the richest wind (east central portion) and solar (southern portion) resource areas in the United States; New Mexico and Wyoming are hot spots for wind development due to prevalence of low-cost and temporally uncorrelated wind, and the Southwest is seeing strong buildout of solar, including utility scale and DERs.
- Heterogeneity of state policies related to renewables creates challenges for multi-state backbone projects; Colorado, New Mexico, Nevada, Oregon, and Washington have targets of 50% or higher; Idaho and Wyoming have no standard.
- Abundant hydro resources in the Northwest could play a role in balancing increasing amounts of variable generation across the Western Interconnection if there is sufficient long-haul transmission capacity to other parts of the region.
- Majority of transmission projects in recent years have been executed within the four discrete planning areas in WECC*, though six interregional projects are currently being developed across seams.
- Opportunities to increase transfer capacity across seams with Canada, SPP, ERCOT**, and California ISO for broader footprint for renewable resource optimization, particularly to accommodate growing demand for renewables within California, as well as the need to reduce curtailments at times of excess generation within California.
- Developing long-distance, high-voltage transmission through remotely populated Western areas poses unique challenges: terrain, distance, and impacts on federal, native lands.

*Western Electric Coordinating Council
**Electric Reliability Council of Texas

Regional Transmission Summary – California ISO

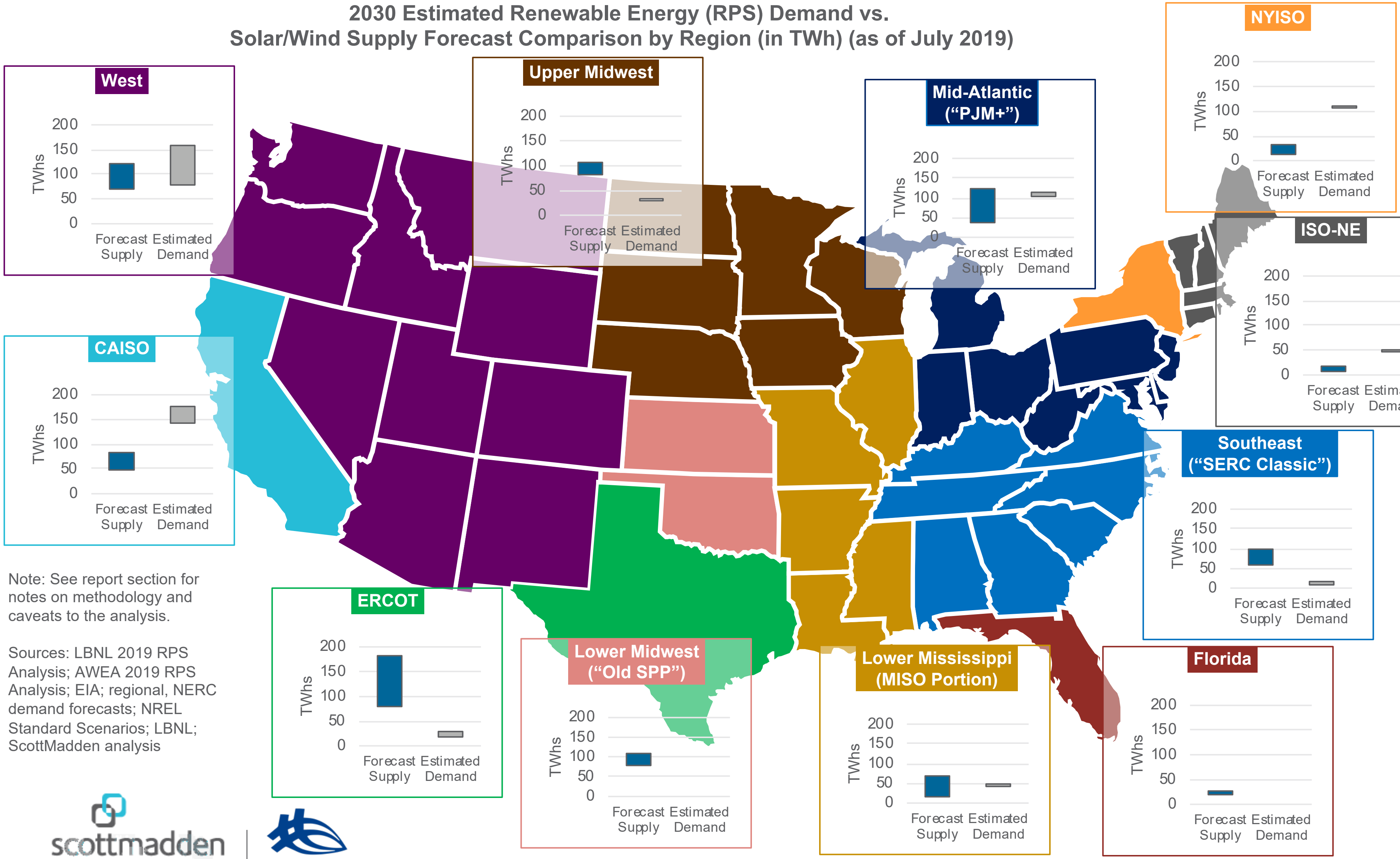


- Ambitious clean energy goals: 50% by 2030 and potential for in-state demand to vastly exceed in-state renewables supply suggests opportunity for more imports from adjacent regions, particularly increasing transfer capacity with the Northwest.
- Increasing curtailments of in-state renewables at times of oversupply could create opportunities to move power to areas where it can be used.
- Expansion of the Western Energy Imbalance Market, which includes almost three-fourths of the load in the Western Interconnection, continues; introduction of a day-ahead market may create opportunities to streamline intraregional and interregional transmission planning.
- New wind and gas generation development has driven interconnection needs in recent years, but new solar represents the majority of capacity currently in the queue.
- Resilience concerns, including wildfires and gas-power interdependence, points to potential need for increased capacity at interfaces with other regions in WECC.
- Complications to expansion in region: Preference for non-wires alternatives, siting and permitting.

Interregional Considerations

- **Regional to interregional:** Generally, the regional view takes into account grid characteristics and resources. Policy across the country has evolved and been implemented based upon this regional view. However, as the need for integration of renewables and access to low cost energy resources grows, the need for interregional transmission is increasing. Renewables are not evenly distributed; they are concentrated in various regions which don’t necessarily align with where the greatest needs are emerging.
- **Benefits of a larger grid footprint:** A larger grid footprint or balancing area provides advantages for both integration of all types of generation and resilience. A number of studies have pointed to the benefits of increased interregional transmission to accommodate higher penetrations of renewable resources:
  - A study of the Western Interconnection found that increasing balancing area coordination with more transmission connecting larger geographic areas helped diversify the variability of both load and resources and created cost savings due to increased reserve sharing.
  - A similar study of the Eastern Interconnection found that with increased (up to 30% with a significant portion being wind) renewable resources, greater levels of interconnection through transmission led to increased interregional power flows and illustrates that interregional transmission is one way to potentially reduce operational impacts of increasing RPS requirements.
  - More recently, the National Renewable Energy Laboratory has been conducting an Interconnection Seams Study, still to be completed. But it has identified opportunities for increased integration among the U.S. interconnections as providing opportunities for cost savings and possibly resilience, by bringing low cost resources, including remote renewables, to market.
- **Case studies:** Additional case studies point to benefits of interregional transmission capacity. The Western Energy Imbalance Market leverages excess transmission capacity to move excess midday solar energy from California to other areas of the West, as well as allowing for support for late-day ramping needs in California and elsewhere, leading to cost savings for all participants. Moreover, Europe has been expanding its transmission grid to aid in integrating hydro, offshore wind, and onshore wind as it seeks to meet European Union power sector emissions targets.
- **Renewable portfolio standard (RPS) supply vs. demand:** Finally, as RPS’s become more ambitious and clean energy goals advance at the state and utility level, and renewables development is mixed and geographically diverse, RPS supply-demand “imbalances” are potential indicators of increased needs for import and export capability across regions

Interregional Considerations (Cont'd)



2030 estimates
Clean energy demand (standards): 600 TWh (per LBNL) to 714 TWh (latter is ~17% of U.S. retail sales)

Key Takeaways

- As shown here, by 2030, many regions are projected to have adequate or excess renewable supply compared with "headline" clean energy demand.
- The West (including California), New England, and New York appear to have opportunities for additional supply, perhaps through imports from other regions.
- This analysis does not include corporate, utility, or state clean energy "goals" that do not have regulatory or legislative force; thus, additional potential regional demand for renewables may be higher.

Note: See report section for notes on methodology and caveats to the analysis.

Sources: LBNL 2019 RPS Analysis; AWEA 2019 RPS Analysis; EIA; regional, NERC demand forecasts; NREL Standard Scenarios; LBNL; ScottMadden analysis

Resilience

- **FERC definition:** FERC defines resilience as the ability [of the electric system] to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.
- **NERC's framework:** The North American Electric Reliability Corporation (NERC), the designated electric reliability organization, has proposed a framework envisions four elements, reflecting different parts of an event occurrence:
  - Robustness – the ability to absorb shocks and continue operating
  - Resourcefulness – the ability to detect and manage a crisis as it unfolds
  - Rapid Recovery – the ability to get services back as quickly as possible in a coordinated and controlled manner, taking into consideration the extent of the damage
  - Adaptability – the ability to incorporate lessons learned from past events to improve resilience
- **Regional variations:** Resilience issues vary between regions and even within large regions. Some resilience issues are common because they are global in nature. Many threats vary because of location and vulnerability of infrastructure, proximity to resources (including fuel), weather patterns, climatic trends, and seismic conditions. Many regions are concerned about extreme weather as reliability, and often termed as resilience, risks. In particular, extreme cold weather and its impact on an increasingly natural gas-dependent fleet as well as very high penetration of variable energy resources, are being studied.
- **Transmission as potentially enhancing resilience:** Transmission is a component of a more resilient system in providing access to reserves and energy during extreme conditions, leveraging weather diversity. Moreover, as facilities in an aging U.S. transmission system are replaced, they are being upgraded with capabilities that improve resilience, such as technologies for situational awareness and hardened structures.

Resilience vs. Reliability: Different Stakeholders, Cost-Bearers, Responsibilities, and Levels of Planning Maturity

Planning criteria	Well-established N-2 planning	Unspecified or incipient "black swan" planning
Scenarios considered	Stated contingencies	Unlikely/unknown contingencies beyond reliability planning
Primary focus	Prevention, protection, and risk mitigation	Critical infrastructure recovery; social stability
Potential value of event "insurance"	Estimable through system modeling	Difficult to ascertain; policy-driven
Costs borne by	Ratepayers	Taxpayers
Funded by	Utility capital expenditures	• Federal emergency funds • State infrastructure • Municipal, county government
First response responsibility	Utility	Government, community response
Stakeholder coordination	Utility, ISO led	Government led

There remains a planning gap between reliability and resilience. Transmission planners, operators, and owners continue to focus on reliability, including weather and fuel dependency, as those are most clearly actionable and related to electric infrastructure investment. Resilience has broader societal implications involving more stakeholders with government as a key facilitator. And its costs are more properly a societal decision. While transmission has an important role to play, it is only one piece of resilience preparation.

Sources: ScottMadden analysis; 2019 State of Reliability

Challenges

- **Siting and permitting:** The issues with siting and permitting across multiple jurisdictions have long been highlighted as challenges to building both intra- and interregional transmission.
- **Policy evolution needed:** The fact that transmission is needed across the country to support both reliability and integration of renewable resources is well-documented; the evolution of policy has not supported this basic understanding. Incentive policy, which drove significant investments through the 2000s is changing, and returns on equity and adders are being reduced.
- **Legacy of Order 1000:** Order 1000 interregional processes have not materialized to facilitate broader integration across markets. The same cost-allocation challenges, which we once discussed at the regional level, have now moved to the interregional level, identifying beneficiaries and allocating costs appropriately, particularly across regions with different methodologies is challenging.
- **Need for forcing function:** Until a forcing function requires these regions to develop a methodology that facilitates largely public policy projects, the hope of interregional transmission meeting national needs for transmission (to serve any purpose, let alone clean energy) will remain elusive.
  - State and local policy continues to stymie transmission development through siting and permitting processes that are poorly aligned.
  - Environmental interests stack up on both sides of the transmission development debate. Some organizations acknowledge the degree to which transmission is needed to facilitate renewables integration. Others focus on the environmental impacts of specific corridors, slowing or stopping permitting and construction. There is also a view that DERs can offset the need for central station (utility-scale) generation and transmission.
  - Economic development always points to local resources serving local load; states are focusing on in-state resources to meet RPS and clean energy targets, making the case for interregional collaboration more difficult.

What has changed in the last two years or so is the degree to which states, utilities, and other companies are committing to 100% carbon free portfolios. It is not possible to meet these goals without intraregional, and in some cases interregional, transmission connecting these resources to load.

Policy Implications

- **Targeted federal policy:** Significant transmission development followed the Energy Policy Act of 2005 and FERC incentives policy that followed; similar national policy could be beneficial in creating a framework for transmission development that would be supported by myriad stakeholders.
- **Fostering interregional transmission:** In the absence of a national framework, the following should be considered to spur interregional transmission development:
  - FERC should step forward and begin to assess more proactive approaches to creating the framework for interregional collaboration in light of company, state, and regional goals related to clean energy.
  - There is an opportunity to reconsider the current trend in transmission incentives if there is a desire to have companies undertake these large interregional projects.
  - Stakeholders focused on clean energy need to further articulate the critical role of transmission in facilitating company, state, and regional goals for clean energy.
  - As utilities (and others) put forward clean energy and carbon free goals, they should also highlight the role that transmission plays in facilitating this transition.
- **Education:** The network and other positive effects of transmission need to be more broadly understood and communicated.
- **Role of transmission:** As regions and states develop and communicate clean energy goals, they should work with the RTO/ISO to understand the degree to which these goals must be facilitated by transmission (both intra- and interregional).

There is the potential to align myriad stakeholders in support of transmission development. The benefits to these divergent groups need to be clearly communicated to garner support for this infrastructure.

Structure of the Report

- This report is structured in sections.
  - Section 1 is this Executive Summary, which highlights key points of the report including a snapshot of the regions profiled herein.
  - Section 2, titled Industry Backdrop, describes four important trends in the electric industry in North America and how electric transmission plays a role or complements these trends.
  - Section 3, titled Regional Discussions, and further divided into regional subsections, provides an overview of the regions reviewed in this study (and summarized earlier in this executive summary) consisting of key statistics, a view of the region's transmission topography and investment, trends and drivers of renewables development, resilience issues, and a summary of issues for transmission in the region.
  - Section 4, titled Interregional Considerations, examines studies, case studies, and drivers for interregional transmission, considering grid needs driven by renewables supply and demand as well as resilience considerations.
  - Section 5, titled Resilience, examines non-region-specific resilience issues, including the industry's evolving resilience framework, selected events and how the grid enabled a robust response, and potential investment in grid capabilities to support resilience.
  - Section 6, titled Challenges and Policy Implications, looks at some of the issues regarding interregional planning, cost allocation, resilience planning, and local siting and permitting of transmission, and considerations for policymakers and stakeholders.

Notes and Acknowledgments

Notes

- This report uses publicly available sources and is dependent upon accuracy and completeness of these resources. Data and information provided in this report is valid to the best of our knowledge as of October 2019.
- The energy industry, and the power transmission sector in particular, is a dynamic, changing business, legal, and regulatory environment. Any changes and developments, including commission or agency findings and decisions, updated planning documents, and other resources relied upon herein occurring or released after October 2019 are not necessarily reflected in this report.

Acknowledgments

- The report was informed by input from WIRES member organization representatives. We extend our thanks to the WIRES Group, its members, and in particular the working group that was engaged in discussing and reviewing this report. Their assistance and insights, particularly into (but not limited to) regional dynamics, were invaluable. Errors and omissions in this report are ours alone.

Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal

Released January 2015

(Revised from June 2014)

Energy+Environmental Economics

Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal

Released January 2015

(Revised from June 2014)

Energy and Environmental Economics, Inc.

101 Montgomery Street, Suite 1600

San Francisco, CA 94104

415.391.5100

www.ethree.com

Table of Contents

Table of Figures

Table of Tables

Executive Summary

This study examines the potential role of decarbonized pipeline gas fuels, and the existing gas pipeline infrastructure, to help meet California's long-term climate goals. The term "decarbonized gas" is used to refer to gaseous fuels with a net-zero, or very low, greenhouse gas impact on the climate. These include fuels such as biogas, hydrogen and renewable synthetic gases produced with low lifecycle GHG emission approaches. The term "pipeline gas" means any gaseous fuel that is transported and delivered through the natural gas distribution pipelines. Using a bottom-up model of California's infrastructure and energy systems between today and 2050 known as PATHWAYS (v.2.1), we examine two "technology pathway" scenarios for meeting the state's goal of reducing greenhouse gas (GHG) emissions to 80 percent below 1990 levels by 2050:

+ **Electrification scenario**, where all energy end uses, to the extent feasible, are electrified and powered by renewable electricity by 2050;
+ **Mixed scenario**, where both electricity and decarbonized gas play significant roles in California's energy supply by 2050.

Both scenarios meet California's 2020 and 2050 GHG goals, to the extent feasible, accounting for constraints on energy resources, conversion efficiency, delivery systems, and end-use technology adoption. Across scenarios, we compare total GHG emissions, costs, and gas pipeline utilization over time relative to a Reference scenario, which does not meet the 2050 GHG target.

The study concludes that a technology pathway for decarbonized gas could feasibly meet the state's GHG reduction goals and may be easier to implement in some sectors than a high electrification strategy. We find that the total costs of the decarbonized gas and electrification pathways to be comparable and within the range of uncertainty. A significant program of research and development, covering a range of areas from basic materials science to regulatory standards, would be needed to make decarbonized gas a reality.

The results also suggest that decarbonized gases distributed through the state's existing pipeline network are complementary with a low-carbon electrification strategy by addressing four critical challenges to California's transition to a decarbonized energy supply.

+ First, decarbonized pipeline gas can help to reduce emissions in sectors that are otherwise difficult to electrify, either for technical or customer-acceptance reasons. These sectors include: (1) certain industrial end uses, such as process heating, (2) heavy duty vehicles (HDVs), and (3) certain residential and commercial end uses, such as cooking, and existing space and water heating.
+ Second, the production of decarbonized gas from electricity could play an important role in integrating variable renewable generation by producing gas when renewables are generating power, and then storing the gas in the pipeline distribution network for when it is needed.
+ Third, a transition to decarbonized pipeline gas would enable continued use of the state's existing gas pipeline distribution network, eliminating

the need for new energy delivery infrastructure to meet 2050 GHG targets, such as dedicated hydrogen pipelines or additional electric transmission and distribution capacity.

+ Fourth, pursuit of decarbonized gas technologies would help diversify the technology risk associated with heavy reliance on a limited number of decarbonized energy carriers, and would allow consumers, businesses and policymakers greater flexibility and choice in the transition to a low-carbon energy system.

1 Introduction

California has embarked on a path to dramatically reduce its GHG emissions over the next four decades. In the nearer term, Assembly Bill 32 (AB 32) requires the state to reduce GHG emissions to 1990 levels by 2020. The state appears to be on track to meet this goal. In the longer term, Executive Order S-3-05 sets a target for California to reduce GHG emissions by 80% relative to 1990 levels by 2050. Achieving this target will require significant changes in the state's energy systems over the coming decades; the state's energy supply will need to be almost entirely carbon free by mid-century.

Natural gas and other gaseous fuels face an uncertain future in California's energy supply mix. The need to reduce the carbon intensity of the state's transportation fuels and industrial output to meet near- to medium-term GHG goals opens up opportunities for natural gas as a substitute for more carbon-intensive oil and coal. However, natural gas from traditional fossil fuel sources cannot represent a significant share of energy use by 2050 if the state is to meet its long-term GHG goal. By 2050, traditional uses of oil and natural gas, including transportation fuels, water and space heating, and industrial boilers and process heating, will need to be mostly, if not fully, decarbonized.

Solutions for achieving a deep decarbonization of California's energy supply have focused on extensive electrification using renewable energy sources, with some liquid biofuel and hydrogen fuel use in the transportation sector. However, there are three principal challenges associated with this decarbonization "pathway." First, there are practical limits to electrifying some energy end uses, such as HDVs and industrial process heating. Second, there are physical limits on sustainable biomass resources, which limit the amount of biomass that can be used as a primary energy source. Third, very high levels of renewable penetration require large-scale energy storage solutions, to integrate wind and solar generation on daily and seasonal timescales. Decarbonized[1] gas fuels distributed through the state's extensive existing gas pipeline network offer a little-explored strategy for overcoming some of these challenges and meeting the state's GHG goals.

To examine the roles of gas fuels in California and utilization of the state's existing gas pipeline infrastructure from now until 2050, Southern California Gas Company (SCG) retained Energy and Environmental Economics (E3) to address four main questions:

1. Are there feasible technology pathways for achieving California's nearer- and longer-term GHG targets where gaseous fuels continue to play a significant role?
2. If yes, how do these pathways compare against a reference case and a "high electrification" strategy in terms of GHG emissions and costs?How does the use of the state's gas pipeline infrastructure differ under scenarios where more and less of the state's energy supply is electrified?
3. In what key areas would research, development, and demonstration (RD&D) be needed to produce decarbonized gas on a commercial scale?

[1] Throughout this report, the term "decarbonized gas" refers to gases that have a net-zero, or very low, impact on the climate, accounting for both fuel production and combustion.

To provide an analytical framework for addressing these questions, we develop two "technology pathway" scenarios that represent different points along a spectrum between higher and lower levels of electrification of energy end uses by 2050:

(1) "Electrification" scenario, where most of the state's energy consumption is powered with renewable electricity by 2050;

(2) "Mixed" scenario where decarbonized gas replaces existing natural gas demand and fuels HDVs, but renewable energy is used to produce electricity and to power most light-duty vehicles (LDVs).

The decarbonized gas technologies examined in this study were selected to represent a range of different options, but are not intended to be exhaustive. The focus in this study is on more generally examining the role of gas fuels over the longer term in a low-carbon energy system, not on comparing different emerging decarbonized gas options.[2] These scenarios are compared to a Reference scenario where current policies are unchanged through 2050 and the state's GHG target is unmet. Table 1 shows a high-level summary of key differences among these three scenarios.

[2] A number of emerging technology options for low-carbon gas, such as artificial photosynthesis, are thus not included in the list of technology options examined in this study. Including these technologies would likely reinforce many of the main conclusions in this study.

Table 1. High-level summary of key differences among the three scenarios examined in this analysis

Scenario	Source of residential, commercial, industrial energy end uses	Source of transportation fuels	Source of electricity supply	Source and amount of decarbonized pipeline gas[3]
Electrification	Mostly electric	Mostly electric LDVs, mostly hydrogen fuel cell HDVs	Renewable energy, some natural gas with CCS	Small amount of biogas
Mixed	Decarbonized gas for existing gas market share of end uses	Electric LDVs, Decarbonized gas in HDVs	Renewable energy, some natural gas with CCS	Large amount of biogas, smaller amounts of SNG, hydrogen, natural gas
Reference	Natural gas	Gasoline, diesel	Mostly natural gas	None

Both the Electrification and Mixed scenarios were designed to meet California's 2020 and 2050 GHG targets. For each scenario we analyzed its technical feasibility and technology costs using a bottom-up model of the California economy. This model (California PATHWAYS v2.1), which includes a detailed "stock-rollover" representation of the state's building, transportation, and energy infrastructure, allows for realistic depiction of infrastructure turnover and technology adoption; sector- and technology-based matching of energy demand and supply; and detailed energy system representation and technology coordination. The model includes hourly power system dispatch and realistic

[3] Throughout this report, the term "pipeline gas" is used to encompass different mixes of gas in the pipeline, including conventional natural gas, gasified biomass, hydrogen (initially limited to 4% of pipeline gas volume, with up to 20% allowed by 2050), and gas produced from P2G methanation.

operating constraints. An earlier version of the model was peer reviewed as part of an article published in the journal *Science*.[4]

The identification of realistic sources of decarbonized gas is a critical piece of this analysis. We considered three energy carriers for decarbonized gas, each with different potential primary energy sources:

+ **Biogas**, which includes gas produced through biomass gasification (biomass synthetic gas) and anaerobic digestion of biomass;
+ **Hydrogen**, produced through electrolysis; and
+ **Synthetic natural gas (SNG)**, produced through electrolysis with renewables (mostly wind and solar "over-generation") and further methanated into SNG in a process referred to as power-to-gas (P2G) throughout this report.[5]

By 2050, there are a limited number of primary energy sources available to supply decarbonized energy: renewable electricity, biomass, nuclear, or fossil fuels with carbon capture and sequestration (CCS). Each has different scaling constraints. For instance, wind and solar energy are intermittent and require energy storage at high penetration levels. Hydropower and geothermal energy are constrained by land and water use impacts and the availability of suitable

[4] James H. Williams, Andrew DeBenedictis, Rebecca Ghanadan, Amber Mahone, Jack Moore, William R. Morrow III, Snuller Price, Margaret S. Torn, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science* 335: 53-59.

[5] P2G, though often used generically to refer to any process that converts electricity to gas, refers specifically to electrolysis and hydrogen methanation in this report. The methanation reaction requires a source of CO_2, which we assume to be air capture in this study, although carbon capture from seawater is another promising, emerging technology. This extra methanation step, and the costs of seawater carbon capture, or air capture, makes P2G relatively expensive. We examined this technology in this study primarily for its electricity storage benefits. Other potential low-carbon gas production technologies, such as synthetic photosynthesis, are not examined within the scope of this study.

sites for development. Bioenergy is limited by the amount of feedstock that can be sustainably harvested. Nuclear is limited by public acceptance and the lack of long-term storage and disposal of spent fuel. Carbon capture and sequestration is also limited by public acceptance and generates higher emissions than the other options due to partial capture rates of CO_2. Choices of primary energy sources for a decarbonized energy supply require tradeoffs in costs, reliability, externalities, and public acceptance.

Similar limits and tradeoffs exist with conversion pathways from primary energy to secondary energy carriers, often with multiple interrelated options. Biomass, for instance, can be converted into a number of different energy carriers (e.g., liquid biofuels, biogas, hydrogen, electricity) through multiple energy conversion processes. P2G is only cost-effective from an energy system perspective when there is significant renewable over-generation. Fossil fuels can be converted into partially decarbonized energy with carbon capture and sequestration (CCS). Evaluating different decarbonized gas technology options — primary energy sources, energy conversion pathways, and energy carriers — thus requires realistic scaling constraints, an integrated energy system perspective, and strategies for managing uncertainty and complexity.

Our modeling framework addresses these requirements by: consistently constraining physical resources (e.g., biomass availability), conversion efficiencies (e.g., gasification efficiency), and gas distribution (e.g., limits on hydrogen gas volumes in pipelines); allowing for interrelationships among energy sources (e.g., electricity and gas); accounting for system costs and GHG emissions across a range of technologies; and exploring different potential options under a range of inputs and avoiding over-reliance on point estimate assumptions as the driver of technology adoption. The results of this study confirm that the electricity sector will be pivotal to achieving a low-carbon future in California — in both the Electrification and Mixed scenarios the need for low-carbon electricity increases substantially. The results also suggest that decarbonized gases distributed through the state's existing pipeline network are complementary with a low-carbon electrification strategy by addressing four critical challenges to California's transition to a decarbonized energy supply.

- First, decarbonized pipeline gas can help to reduce emissions in sectors that are otherwise difficult to electrify, either for technical or customer-acceptance reasons. These sectors include: (1) certain industrial end uses, such as process heating, (2) HDVs, and (3) certain residential and commercial end uses, such as cooking, existing space heating, and existing water heating.
- Second, the production of decarbonized gas from electricity could play an important role in integrating variable renewable generation by producing gas when renewables are generating power, and then storing the gas in the pipeline distribution network for when it is needed. At high penetrations of variable renewable generation, long-term, seasonal electricity storage may be needed to balance demand and supply, in addition to daily storage. On these longer timescales, gas "storage" may be a more realistic and cost-effective load-resource balancing strategy than flexible loads and long-duration batteries.[6]
- Third, a transition to decarbonized pipeline gas would enable continued use of the state's existing gas pipeline distribution network, reducing or

[6] In this scenario, we assume that electrolysis for hydrogen production, powered by renewable electricity, can be ramped up and down on a daily basis as a dispatchable load in the medium-term. In the long-term, P2G methanation with air capture, or carbon capture from seawater to produce SNG could provide both a source of low-carbon gas and a grid balancing service.

eliminating the need for new energy delivery infrastructure to meet 2050 GHG targets, such as dedicated hydrogen delivery pipelines or additional electric transmission and distribution lines. Increased use of decarbonized gas in the coming decades would preserve the option of continued use of existing gas pipelines as a low-carbon energy delivery system over the longer term.

+ Fourth, pursuit of decarbonized gas technologies would help diversify the technology risk associated with heavy reliance on a limited number of decarbonized energy carriers, and would allow consumers, businesses and policymakers greater flexibility and choice in the transition to a decarbonized energy system.

All of the decarbonized gas energy carriers in this study make use of proven energy conversion processes — none require fundamental breakthroughs in science. Nonetheless, these processes remain relatively inefficient and expensive, and would need significant improvements in conversion efficiency and reductions in costs to be competitive in the medium- to long-term. Additionally, existing gas pipelines and end use equipment were not designed to transport and utilize hydrogen gas, and would require operational changes as the blend of decarbonized gas shifts over time.

Developing a supply of sustainably sourced biomass presents an additional challenge. Biomass resources have competing uses — food, fodder, and fiber — which may limit the amount of sustainably-sourced biomass available for energy production. The Electrification and Mixed scenarios both assume that a limited quantity of sustainably sourced biomass would be available to California in the 2030 and 2050 timeframe. The same quantity of biomass is assumed to produce electricity in the Electrification scenario, and biogas in the Mixed scenario.

However, it remains uncertain whether it will be possible to increase the production of biomass fuels to this scale, as would be needed to significantly reduce fossil fuel use, without negatively impacting food supply or increasing GHG emissions from changes in land use.

Furthermore, current RD&D efforts and policy initiatives have prioritized the production of liquid biofuels, particularly ethanol, over the production of biogas. More generally, the state does not appear to have a comprehensive decarbonized gas strategy, in contrast to low-carbon electricity which is promoted through the state's Renewables Portfolio Standard (RPS) and the decarbonized transportation fuels are encouraged through the state's Low Carbon Fuel Standard (LCFS). Overcoming these challenges would require prompt shifts in policy priorities and significant amounts of RD&D if biofuels, and particularly biogas, are to become an important part of the state's future energy mix.

The results suggest priority areas and time frames, outlined in Table 2, for a RD&D agenda that would be needed if California is to pursue decarbonized pipeline gas as a strategy to help meet the state's GHG reduction goals.

Table 2. RD&D timescales, priorities, and challenges for decarbonized gas fuels

Timeframe of RD&D payoff	RD&D Area	Challenge
Near-term	Energy efficiency	Achieving greater customer adoption and acceptance
	Reduction in methane leakage	Cost-effectively identifying and repairing methane leaks in natural gas mining, processing, and distribution
	Use of anaerobic digestion gas in the pipeline and pilot biomass gasification	Quality control on gas produced via anaerobic digestion for pipeline delivery
Medium-term	Agronomic and supply chain innovation for biomass feedstocks	Competition with liquid fuels, food, fodder, fiber may limit amount of biomass available as a source of decarbonized gas
	Pilot decarbonized SNG technology to improve conversion efficiency and cost	Gasification, electrolysis, and methanation need efficiency improvements, reductions in cost to be competitive; safety, scale, and location challenges must be addressed
	Limits on hydrogen volumes in existing pipelines	Need pipeline and operational changes to accommodate higher volumes
Long-term	Emerging technologies (e.g., P2G, artificial photosynthesis, CO_2 capture from seawater for fuel production)	P2G must be scalable and available as a renewable resource balancing technology; in general, emerging technologies still require innovations in material science

The organization of the report is as follows: Section 2 develops the Reference case and two afore-mentioned scenarios. Section 3 describes the modeling approach and elaborates on the technology pathways for decarbonized gases. Section 4 presents the results. The final section, Section 5, distills key conclusions and discusses their policy and regulatory implications. Further details on methods and assumptions are provided in an appendix.

1.1 About this study

This study was commissioned by SCG to help the company consider their long-term business outlook under a low-carbon future, and to fill a gap in the existing literature regarding long-term GHG reduction strategies that include the use of decarbonized gas in the pipeline distribution network.

A number of studies have evaluated the options for states, countries and the world to achieve deep reductions in GHG emissions by 2050.[7] These studies each make different assumptions about plausible technology pathways to achieve GHG reductions, with varying amounts of conservation and efficiency, CCS, hydrogen fuel cells, nuclear energy, and biofuel availability, to name a few key variables. However, few studies have undertaken an in-depth investigation of the role that decarbonized pipeline gas could play in achieving a decarbonized future.[8]

In our prior work, we highlighted the pivotal role of the electricity sector in achieving a low-carbon future for California.[9] This study for SCG uses an

---

[7] See for example: "Reducing Greenhouse Gas Emissions by 2050: California's Energy Future," California Council on Science and Technology, September 2012; "Roadmap 2050: A practical guide to a prosperous, low-carbon Europe," European Climate Foundation, April 2010; "EU Transport GHG: Road to 2050?," funded by the European Commission, June 2010; "EPA Preliminary Analysis of the Waxman-Markey Discussion Draft," U.S. EPA, April 2009; "Energy Technology Perspectives, 2008: Scenarios & Strategies to 2050," International Energy Agency, 2008; "The Power to Reduce CO_2 Emissions: The Full Portfolio: 2008 Economic Sensitivity Studies," EPRI, Palo Alto, CA: 2008. 1018431; "Building a Low Carbon Economy: The U.K.'s Contribution to Tackling Climate Change," The First Report of the Committee on Climate Change, December 2008; "Making the Transition to a Secure and Low-Carbon Energy System: Synthesis Report," UK Energy Research Center, 2009.

[8] For an example of a deep decarbonization study from Germany that employs both electrolysis and P2G (Sabatier), see Palzer, A. and Hans-Martin Henning, "A Future Germany Energy System with a Dominating Contribution from Renewable Energies: A Holistic Model Based on Hourly Simulation," Energy Technol. 2014, 2, 13 – 28.

[9] James H. Williams, Andrew DeBenedictis, Rebecca Ghanadan, Amber Mahone, Jack Moore, William R. Morrow III, Snuller Price, Margaret S. Torn, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science* 335: 53-59.

updated version of the model (California PATHWAYS 2.1) employed in that prior work, relying on the same fundamental infrastructure-based stock roll-over modeling approach, and many of the same underlying input assumptions, such as energy efficiency potential. However, important updates to the analysis include:

- Updated forecasts of macroeconomic drivers including population and economic growth;
- Updated technology cost assumptions where new information has become available, including for solar photovoltaic (PV) and energy storage costs;
- A more sophisticated treatment of electricity resource balancing, moving from a four time period model (summer/winter & high-load/low-load), to an hourly resource balancing exercise; and
- Slightly higher biomass resource potential estimates, based on new data from the U.S. Department of Energy (DOE).[10]

The model results are driven by exogenous, scenario-defined technology adoption assumptions. Costs of technologies and fuels are exogenous, independent inputs which are tabulated to track total costs. The model does not use costs as an internal decision variable to drive the model results, rather the model is designed to evaluate technology-driven, user-defined scenarios.

[10] U.S. Department of Energy, "U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry," August 2011.

2 Scenarios

2.1 Low-carbon scenarios

Two distinct low-carbon scenarios are developed and compared within this study. Both of these scenarios result in lower GHG emissions than required by California's mandate of reducing emissions to 1990 levels by 2020, and are designed to meet the 2050 goal of reducing GHG emissions 80% below 1990 levels. Each scenario is further constrained to achieve an approximately linear path in GHG reductions between today's emissions and the 2050 goal. The differences between the two scenarios are not in GHG reduction achievements, but between technology pathways, implied RD&D priorities, technology risks, and costs.

The two low-carbon scenarios evaluated include:

+ **Electrification Scenario: This scenario meets the 2050 GHG reduction goal by electrifying most end-uses,** including industrial end uses, space heating, hot water heating, cooking and a high proportion of light-duty vehicles. Low-carbon electricity is produced mostly from renewable generation, primarily solar PV and wind, combined with a limited amount of natural gas with carbon capture and storage (CCS) and 20 GW of electricity storage used for renewable integration. Low-carbon electricity is also used to produce hydrogen fuel for heavy-duty vehicles. California's limited supply of biomass is used largely to generate renewable electricity in the form of biomass generation. In this scenario, the gas distribution pipeline network is effectively un-used by 2050. With very few remaining sales by 2050 and significant remaining fixed distribution costs, it seems unlikely that gas distribution companies would continue to operate under this scenario.

+ **Mixed Scenario: This scenario meets the 2050 GHG reduction goal with a blend of low-carbon electricity and decarbonized pipeline gas.** Existing uses for natural gas in California, such as industrial end uses (i.e. boilers and process heat), space heating, hot water heating and cooking are assumed to be supplied with decarbonized pipeline gas, such that the current market share for pipeline gas is maintained over time. California's limited supply of biomass is used to produce biogas which is injected into the pipeline. Over time, this scenario assumes that an increasing share of hydrogen is blended into the pipeline gas, which is assumed to be produced from renewable power (mostly solar and wind) using electrolysis. This scenario includes a significant increase in electric light-duty vehicles, while most heavy-duty vehicles are assumed to be powered with compressed or liquefied decarbonized gas and liquid hydrogen fuel. Electricity is produced mostly from renewable generation, primarily solar PV and wind, with a limited amount of natural gas with CCS and 5 GW of electricity storage used for renewable integration. Load balancing services are primarily provided by cycling the production of decarbonized gas to match the renewable generation profiles. In this way, the decarbonized pipeline gas provides both daily and seasonal energy storage. The Mixed scenario represents neither a significant expansion nor contraction of the gas pipeline distribution system. In this scenario, both the gas pipeline network and the electricity transmission and distribution system operate as conveyors of decarbonized energy.

The key parameters of these scenarios are summarized in Table 3 below.

Table 3. Summary of Low-Carbon Scenarios Based on Key Parameters in 2050

Scenario	Source of residential, commercial, industrial energy end uses	Source of transportation fuels	Source of electricity supply & resource balancing	Uses of biomass
Electrification	Mostly electric	Mostly electric light-duty vehicles, mostly hydrogen HDVs	Renewable energy, limited natural gas with CCS, 5 GW of pumped hydro energy storage and 15 GW of battery energy storage, some hydrogen production	Electricity generation, small amount of biogas
Mixed	Decarbonized gas (biogas, SNG & hydrogen) for existing gas market share of end uses	Decarbonized gas in HDVs; electric light duty vehicles (LDVs)	Renewable energy, limited natural gas with CCS, 5 GW of pumped hydro energy storage, plus P2G and hydrogen production assumed to provide resource balancing services	Biogas

Both of the low-carbon scenarios evaluated here entail different assumptions about the future feasibility and commercialization of key technologies to achieve an 80 percent reduction in GHGs relative to 1990. For the Electrification scenario to be viable, significant amounts of long-term electricity storage must be available on a daily and seasonal basis to balance intermittent renewable generation. The Electrification scenario also relies significantly on the production of low carbon liquid biofuels and hydrogen fuel cell vehicles in the transportation sector, for vehicles that are otherwise difficult to electrify. For the Mixed scenario to succeed, it must be possible to produce large quantities of biogas using sustainably-sourced biomass. Furthermore, the Mixed scenario depends on eventual adoption of P2G methanation with carbon capture from sea water or air capture to produce SNG. All of the technologies that are applied in these scenarios are technically feasible; the science exists today. The challenge is commercializing and scaling these technologies to provide a significant energy service to California before 2050. In Table 4 below, the emerging technologies applied in the low-carbon scenarios are ranked based on their "risk" to the scenario's success. Risk is determined by ranking the amount of energy that passes through each technology in 2050 for a given scenario (higher energy use implies higher reliance on the technology), combined with a measure of the technology's current commercialization stage (lower availability implies higher risk).

Table 4. Ranking of emerging technology's criticality to the Electrification and Mixed scenarios

Emerging Technologies	Overall Ranking of Technology Criticality by 2050 (maximum = 9 for most critical, minimum = 0 for least critical)	
	Electrification	Mixed
Availability of sustainably-sourced biomass	6	9
Power-to-gas methanation using carbon capture from seawater or air	0	6
Battery storage for load balancing	9	0
Carbon capture and storage	3	3
Cellulosic ethanol	6	0
Hydrogen production	4	4
Use of hydrogen in the distribution pipeline	0	4
Gasification to produce biogas	1	3
Fuel cells in transportation (HDVs)	6	3
Electrification of industrial end uses	2	0

2.2 Common strategies and assumptions across all low-carbon scenarios

Both of the low-carbon scenarios described above include a number of other carbon reduction efforts that must be implemented to achieve the state's long-term GHG reduction goal. These other assumptions do not vary between scenarios, and include low-carbon measures such as:

- Significant levels of energy efficiency in all sectors, including transportation efficiency, industrial and building efficiency;
- Significant reductions in non-CO_2 and non-energy GHG emissions, such as methane emissions and other high-global warming potential gases such as refrigerant gases;
- Improvements in "smart growth" planning as per Senate Bill 375,[11] leading to reductions in vehicle miles traveled (VMT) and increased urban density leading to lower building square footage needs per person;
- All scenarios include the use of sustainably-sourced biomass to produce decarbonized energy. The scenarios differ in how the biomass is used, to produce electricity, liquid or gas fuels.
- All scenarios include an increase in electrification relative to today; the scenarios differ in how much additional electrification is assumed relative to other sources of low-carbon energy;
- Flexible loads for renewable resource balancing, including limited use of controlled charging of electric vehicles and a limited share of certain residential and commercial electric thermal end uses.[12] Hydrogen and P2G production are assumed to provide fully dispatchable, perfectly flexible load-following services, helping to integrate variable renewable generation in the low-carbon scenarios.

[11] The Sustainable Communities and Climate Protection Act of 2008
[12] Up to 40 percent of electric vehicle charging load is assumed to be flexible within a 24-hour period to provide load-resource balancing services. Electric vehicles are not assumed to provide energy back to the electric grid, in a "vehicle-to-grid" configuration.

+ Imports of power over existing transmission lines are limited to a historical average and are assumed to maintain the same emissions intensity throughout the study period. New, dedicated transmission lines for out-of-state renewable resources are also tracked. Exports of electricity from California of up to 1500 MW are allowed.

2.3 Reference case

In addition to the low-carbon scenarios evaluated here, a Reference case is developed as a comparison point. The Reference case assumes a continuation of current policies and trends through the 2050 timeframe with no incremental effort beyond 2014 policies to reduce GHG emissions. This scenario is not constrained to achieve specific GHG reduction goals. As a result, this scenario misses the state's GHG reduction targets in 2050 by a wide margin, with 2050 emissions 9% above 1990 levels. In the Reference case current natural gas end uses, such as space heating and hot water heating, continue to be supplied with natural gas through 2050. With no future efforts, California achieves a 33% RPS by 2020 and maintains this share of renewable energy going forward. The transportation sector continues to be dominated by the use of fossil-fueled vehicles in the Reference case.

3 Analysis Approach

3.1 PATHWAYS model overview

This analysis employs a physical infrastructure model of California's energy economy through 2050. The model, known as PATHWAYS (v2.1), was developed by E3 to assess the GHG impacts of California's energy demand and supply choices over time. The model tracks energy service demand (i.e. VMT) to develop a projection of energy demand and the physical infrastructure stock utilized to provide that service (i.e. types and efficiency of different vehicles). End uses in the building sector, vehicles in the transportation sector, and power plants in the electricity sector are tracked by age and vintage, such that new technologies are adopted as older technologies and are replaced in a stock roll-over representation of market adoption rates.

Technology lifetimes, efficiency assumptions and cost data are generally drawn from the U.S. DOE National Energy Modeling System (NEMS), used to support development of the Annual Energy Outlook 2013. Assumptions about new technology adoption are highly uncertain, and are defined by E3 for each scenario. New technology adoption rate assumptions are selected to ensure that the low-carbon scenarios meet the state's 2050 GHG reduction goal.

The model can contextualize the impacts of different individual energy technology choices on energy supply systems (electricity grid, gas pipeline) and energy demand sectors (residential, commercial, industrial) as well as more broadly examine disparate strategies designed to achieve deep de-carbonization targets. Below, Figure 1 details the basic modeling framework utilized in PATHWAYS to project results for energy demand, statewide GHG emissions, and costs for each scenario.

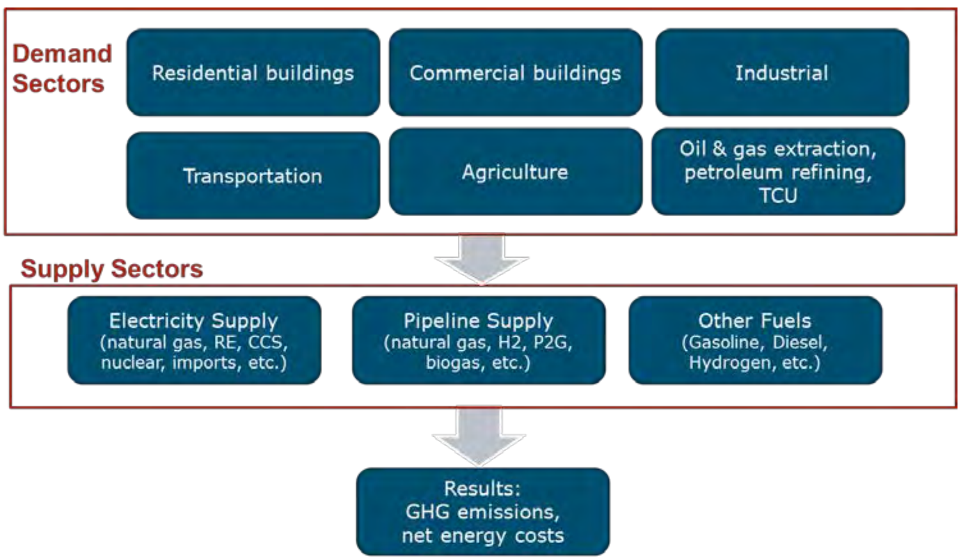


Figure 1. Basic PATHWAYS modeling framework

- **Energy Demand:** projection of energy demand for ten final energy types. Projected either through stock roll-over or regression approach.
- **Energy Supply:** informed by energy demand projections. Final energy supply can be provided by either conventional primary energy types (oil; natural gas; coal) or by decarbonized sources and processes (renewable electricity generation; biomass conversion processes; CCS). The energy supply module includes projections of costs and GHG emissions of all energy types.

- **Summary Outputs:** calculation of total GHG emissions and costs (end-use stocks as well as energy costs). These summary outputs are used to compare economic and environmental impacts of scenarios.

PATHWAYS V2.1 projects energy demand in eight sectors, and eighty sub-sectors, as shown below in Table 5.

Table 5. PATHWAYS Energy Demand Sectors and Subsectors

Sector	Subsector
Residential	Water Heating, Space Heating, Central AC, Room AC, Lighting, Clothes Washing, Dish Washing, Freezers, Refrigeration, Misc: Electricity Only, Clothes Drying, Cooking, Pool Heating, Misc: Gas Only
Commercial	Water Heating, Space Heating, Space Cooling, Lighting, Cooking, Refrigeration, Office Equipment, Ventilation
Transportation	Light Duty Vehicles (LDVs), Medium Duty Trucking, Heavy Duty Trucking, Buses, Passenger Rail, Freight Rail, Commercial Passenger Aviation, Commercial Freight Aviation, General Aviation, Ocean Going Vessels, Harborcraft
Industrial	Mining, Construction, Food & Beverage, Food Processing, Textile Mills, Textile Product Mills, Apparel & Leather, Logging & Wood, Paper, Pulp & Paperboard Mills, Printing, Petroleum and Coal, Chemical Manufacturing, Plastics and Rubber, Nonmetallic Mineral, Glass, Cement, Primary Metal, Fabricated Metal, Machinery, Computer and Electronic, Semiconductor, Electrical Equipment & Appliance, Transportation Equipment, Furniture, Miscellaneous, Publishing
Agricultural	Sector-Level Only
Utilities (TCU)	Domestic Water Pumping, Streetlight, Electric and Gas Services Steam Supply, Local Transportation, National Security and International Affairs, Pipeline, Post Office, Radio and Television, Sanitary Service, Telephone, Water Transportation, Trucking and Warehousing, Transportation Service, Air Transportation
Petroleum Refining	Sector-Level Only
Oil & Gas Extraction	Sector-Level Only

For those sectors that can be represented at the stock level – residential, commercial, and transportation – we compute stock roll-over by individual subsector (i.e. air conditioners, LDVs, etc.). For all other sectors, a forecast of energy demand out to 2050 is developed based on historical trends using regression analysis. These two approaches are utilized to project eleven distinct final energy types (Table 6).

Table 6. PATHWAYS Final Energy Types and Sources of Energy

Final Energy Type	
Electricity • many types of renewables, CCS, nuclear, fossil, large hydro.	Gasoline • ethanol & fossil gasoline
Pipeline Gas • natural gas, hydrogen, biogas, SNG	Liquefied petroleum gas (LPG)
Compressed Pipeline Gas • natural gas, hydrogen, biogas, SNG	Refinery and Process Gas
Liquefied Pipeline Gas • natural gas, hydrogen, biogas, SNG	Petroleum coke
Diesel • biodiesel & fossil diesel	Waste Heat
Kerosene-Jet Fuel	

These final energy types can be supplied by a variety of different resources. For example, pipeline gas can be supplied with combinations of natural gas, biogas, hydrogen, and SNG (produced through P2G processes). Electricity can be supplied by hydroelectric, nuclear, coal, natural gas combined cycles and combustion turbines, and a variety of renewable resources including utility-scale & distributed solar PV, wind, geothermal, biomass, etc. These supply composition choices affect the cost and emissions profile of each final energy type. Further methodology description can be found in the Technical Appendix.

3.2 Modeled energy delivery pathways

A decarbonized technology pathway can be thought of as consisting of three stages: (1) the provision of the primary energy itself, (2) the conversion of primary energy into the energy carrier, and (3) the delivery of an energy carrier for final end use. In practice, there can be many variations on this theme, including multiple conversion process steps and the use of CCS. The primary decarbonized energy sources are biomass, renewable and nuclear generated electricity, and natural gas with CCS. The main options for energy carriers in a decarbonized system are electricity, liquid biofuels such as ethanol and biodiesel, and decarbonized gases including biogas, SNG, and hydrogen and decarbonized electricity.

Figure 2 illustrates the main decarbonized technology pathways for delivering energy to end uses represented in the model. In the remainder of this section, we sketch briefly the main low-carbon pathways considered in this study and how they are modeled.

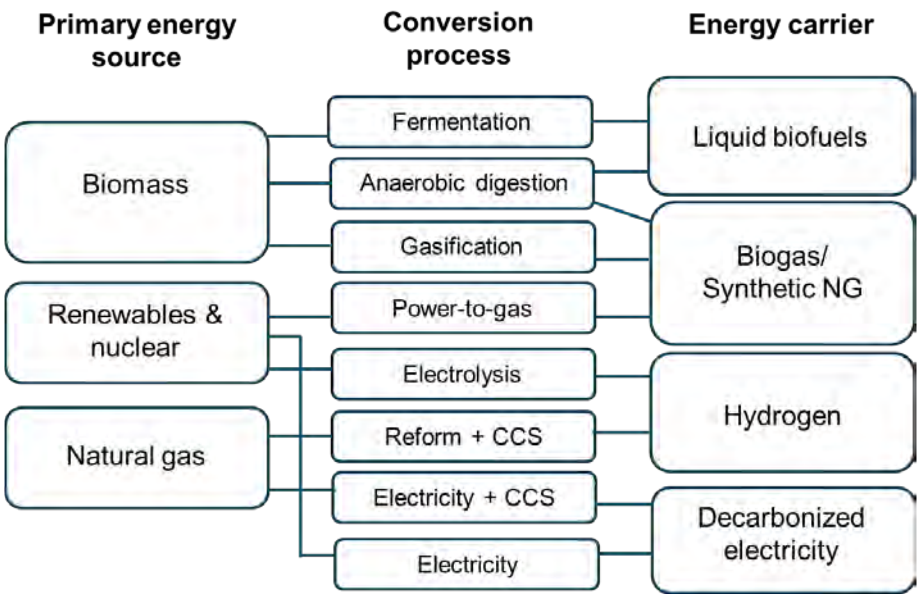


Figure 2. Major low-carbon pathways for delivered energy, from primary energy to conversion process to energy carriers

The technical opportunity for the gas distribution industry lies in providing an alternative to widespread electrification of end uses as an approach to deep decarbonization. The decarbonized gas technologies included in the Mixed scenario have been well-understood and some have been used in commercial applications for decades. For example, synthesized town gas, not natural gas, was the prevalent energy carrier for the first gas distribution companies over a century ago.

However, improvements in cost and efficiency will be required for decarbonized pipeline gas supplies to outcompete other forms of low-carbon delivered energy, such as electricity and liquid biofuels, and other issues require careful consideration and research, such as long-term biomass resource potential and carbon benefits. It is difficult at present to predict which pathways are the most likely to take root and become the dominant forms of energy delivery in a deeply decarbonized world.

3.2.1 BIOMASS RESOURCE ASSUMPTIONS

The principal data source for biofuel feedstocks in our model is the DOE's *Billion Ton Study Update: Biomass Supply for a Bioenergy and Bioproducts Industry* led by Oak Ridge National Laboratory, the most comprehensive available study of long-term biomass potential in the U.S.[13] This study, sometimes referred to as the BT2, updates the cost and potential estimates in the landmark 2005 *Billion Ton Study*, assessing dozens of potential biomass feedstocks in the U.S. out to the year 2030 at the county level (Figure 3).[14]

The estimated future supply of California produced biomass stocks is relatively small compared to the resource potential in the Eastern portion of the U.S., as shown in Figure 3. In this study, we have assumed that California can import up to its population-weighted proportional share of the U.S.-wide biomass feedstock resource potential, or 142 million tons per year by 2030. In the case of the Mixed scenario, where nearly all biomass is assumed to be gasified into biogas, this could be accomplished through production of biogas near the source of of the feedstock, which would then be distributed through the national gas pipeline network. California would not necessarily need to physically import the biomass feedstock into the state in order to utilize, or purchase credits for, the biogas fuel. Under the emissions accounting

[13] U.S. Department of Energy, "U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry," August 2011.
[14] U.S. Department of Energy, "Biomass as a Feedstock for a Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion-Ton Annual Supply," April 2005.

framework employed in this study, California would take credit for assumed emissions reductions associated with these biofuels, regardless of where the fuel is actually produced. This assumption may not reflect California's long-term emissions accounting strategy. Furthermore, there remains significant uncertainty around the long-term GHG emissions impacts of land-use change associated with biofuels production.

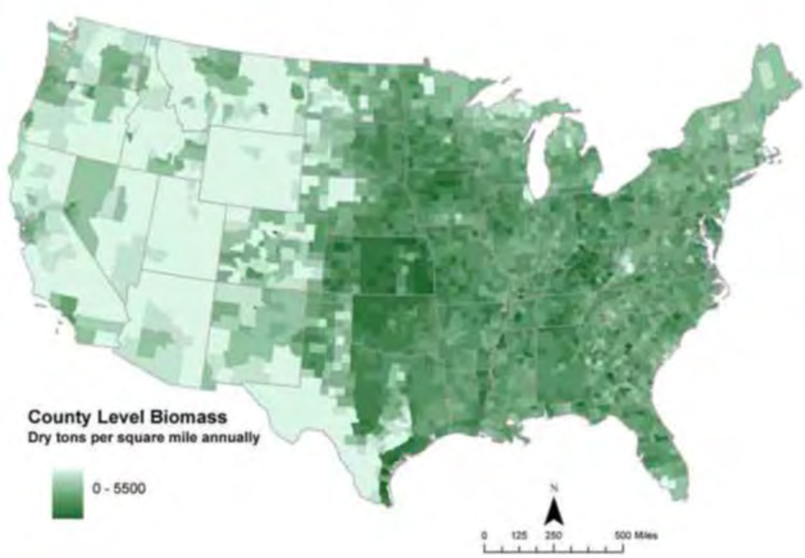


Figure 3. DOE Billions Tons Study Update Biomass Resource Potential (Source: DOE, 2011)

3.2.2 PIPELINE GAS AND LIQUID FUELS FROM BIOMASS

Biomass feedstocks ranging from purpose-grown fuel crops to a variety of agricultural, forestry, and municipal waste products can be converted into decarbonized gas. The main conversion method that is assumed in the Mixed scenario is gasification, including thermal and biochemical variants, which break down complex biomass molecules through a series of steps into a stream of SNG, consisting primarily of hydrogen and carbon monoxide. In the modeled pathway, the SNG is cleaned, shifted, and methanated to produce a pipeline-ready biogas with a high methane content. The other main method for biomass conversion represented in the model is anaerobic digestion. In anaerobic digestion bacterial digestion of biomass in a low-oxygen environment produces a methane-rich biogas which, after the removal of impurities, can be injected into the pipeline. In addition to gas fuels, biomass can be turned into liquid fuels directly through fermentation and distillation, as in the case of ethanol, or through the transesterification of fats such as waste cooking oil to produce biodiesel. Biogas from gasification can also be turned into liquid fuels, for example through the Fischer-Tropsch process.

3.2.3 PIPELINE GAS AND LIQUID FUELS FROM ELECTRICITY AND NATURAL GAS

Renewable energy, fossil generation with CCS and nuclear energy produce low-carbon electricity that can either directly power end uses or be used to produce pipeline gas or liquefied gases for transportation fuels. There are two P2G pathways in the model. One pathway uses electricity for electrolysis to split water and produce hydrogen, which can be injected into the pipeline for distribution up to a certain mixing ratio, or can be compressed or liquefied for use in hydrogen fuel cell vehicles. The other pathway modeled also begins with electrolysis, followed by methanation to produce SNG, which is injected into the pipeline. The SNG pathway requires a source of CO_2, which can come from carbon capture from sea water, air capture or biomass, or under some circumstances from CCS (e.g. situations in which the use of CCS implies no additional net carbon emissions, such as biomass power generation with CCS). The CO_2 and hydrogen are combined into methane through the Sabatier or related process.

Continued use of natural gas under a stringent carbon constraint requires that carbon be captured and stored. The low-carbon scenarios evaluated in this study assume a limited amount of natural gas with CCS is used for electricity generation in both of the low-carbon scenarios. There are two main types of CCS: (1) post-combustion capture of CO_2, and (2) pre-combustion capture of CO_2. In one pathway, CCS occurs after the natural gas has been combusted for electricity generation in a combined cycle gas turbine (CCGT), and the delivered energy remains in the form of decarbonized electricity. In the other pathway, natural gas is subjected to a reformation process to produce hydrogen and CO_2 streams. The CO_2 is captured and sequestered, and the hydrogen can be injected into the pipeline, liquefied for use in fuel cells, or combusted in a combustion turbine.

3.3 Modeling Technology and Energy Costs

3.3.1 GENERAL DESCRIPTION OF APPROACH

For long-term energy pathways scenarios, future costs are particularly uncertain. As a result, the PATHWAYS model does not use technology or energy cost estimates to drive energy demand or resource selection choices. Rather, total capital costs and variable costs of technologies are treated as input variables, which are summed up for each scenario as an indicator of the scenario's total cost. The model does not include a least-cost optimization, nor does the model include price elasticity effects or feedback to macroeconomic outcomes. As such, the model should be understood as primarily a technology and infrastructure-driven model of energy use in California.

The model includes more resolution on cost for two key types of energy delivery: pipeline gas and electricity. These approaches are described in more detail below.

3.3.2 PIPELINE GAS DELIVERY COSTS

We model the California system of delivering pipeline gas as well as compressed pipeline gas, and liquefied pipeline gas for transportation uses. We model these together in order to assess the capital cost implications of changing pipeline throughput volumes. Delivery costs of pipeline gas are a function of capital investments at the transmission and distribution-levels and delivery rates, which can be broadly separated into core (usually residential and small commercial) and non-core (large commercial, industrial, and electricity generation) categories.

Core service traditionally provides reliable bundled services of transportation and natural gas compared to non-core customers with sufficient volumes to justify transportation-only service. The difference in delivery charges can be significant. In September 2013 the average U.S. delivered price of gas to an industrial customer was $4.39/thousand cubic feet compared to

$15.65/thousand cubic feet for residential customers.[15] This difference is driven primarily by the difference in delivery costs and delivery charges for different customer classes at different pipeline pressures.

To model the potential implications of large changes in gas throughput on delivery costs, we use a simple revenue requirement model for each California investor owned utility (IOU). This model includes total revenue requirements by core and non-core customer designations, an estimate of the real escalation of costs of delivery services (to account for increasing prices of materials, labor, engineering, etc.), an estimate of the remaining capital asset life of utility assets, and the percent of the delivery rate related to capital investments.[16]

3.3.3 ELECTRICITY SECTOR AVERAGE RATES AND REVENUE REQUIREMENT

Electricity sector costs are built-up from estimates of the annual fixed costs associated with generation, transmission, and distribution infrastructure as well as the annual variable costs that are calculated in the System Operations Module. These costs are used to calculate an annual revenue requirement of total annualized electric utility investment in each year. These costs are then divided by total retail sales in order to estimate a statewide average electricity retail rates. These average electricity rates are applied to the annual electricity demand by subsector to allocate electricity costs between subsectors.

[15] United States Energy Information Administration, 2013.
[16] We assume that 50% of the revenue requirement of a gas utility is related to throughput growth and that capital assets have an average 30-year remaining financial life. This means that the revenue requirement at most could decline approximately 1.7% per year without resulting in escalating delivery charges for remaining customers.

Transmission and distribution costs are also estimated in the model. Transmission costs are broken into three components: renewable procurement-driven transmission costs, sustaining transmission costs, and reliability upgrade costs. Distribution costs are broken into distributed renewable-driven costs and non-renewable costs. The revenue requirement also includes other electric utility costs which are escalated over time using simple growth assumptions, ("other" costs include nuclear decommissioning costs, energy efficiency program costs and customer incentives, and overhead and administration costs). These costs are approximated by calibrating to historical data. The methodology for calculating fixed generation costs in each year is described below, more details are provided in the Technical Appendix.

3.3.3.1 Generation

Fixed costs for each generator are calculated in each year depending on the vintage of the generator and assumed capital cost and fixed operations and maintenance (O&M) cost inputs by vintage for the generator technology. Throughout the financial lifetime of each generator, the annual fixed costs are equal to the capital cost (which can vary by vintage year) times a levelization factor plus the vintage fixed O&M costs, plus taxes and insurance. This methodology is also used to cost energy storage infrastructure and combined heat and power (CHP) infrastructure. Input cost assumptions for generation technologies are summarized below.[17]

[17] Cost assumptions were informed by E3, "Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process," Prepared for the Western Electric Coordinating Council, Oct. 9, 2012.
<**http://www.wecc.biz/committees/BOD/TEPPC/External/E3_WECC_GenerationCostReport_Final.pdf**>

In general, cost assumptions for generation technologies, as for all technology assumptions in the model, are designed to be conservative, and avoid making uncertain predictions about how the relative costs of different technologies may change over the analysis period. Generation capital cost changes are driven by assumptions about technology learning. As a result, the cost of newer, less commercialized technologies are assumed to fall in real terms, while the costs of technologies that are widely commercialized are assumed to remain constant or to increase.

Table 7. Generation capital cost assumptions

Technology	Capital Cost from present - 2026 (2012$/kW)	Assumed change in real capital cost by 2050 % change	Capital Cost from 2027 - 2050 (2012$/kW)
Nuclear	9,406	0%	9,406
CHP	1,809	0%	1,809
Coal	4,209	0%	4,209
Combined Cycle Gas (CCGT)	1,243	16%	1,441
CCGT with CCS	3,860	-3%	3,750
Steam Turbine	1,245	0%	1,245
Combustion Turbine	996	44%	1,431
Conventional Hydro	3,709	0%	3,709
Geothermal	6,726	0%	6,726
Biomass	5,219	0%	5,219
Biogas	3,189	0%	3,189
Small Hydro	4,448	0%	4,448
Wind	2,236	-9%	2,045
Centralized PV	3,210	-31%	2,230
Distributed PV	5,912	-30%	4,110
CSP	5,811	-25%	4,358
CSP with Storage	7,100	-30%	5,000

3.3.4 COST ASSUMPTIONS FOR ENERGY STORAGE, DECARBONIZED GAS AND BIOMASS DERIVED FUELS

Cost and financing assumptions for energy storage technologies are summarized below. For this analysis, these costs are assumed to remain fixed in real terms over the analysis period.

Table 8. Capital cost inputs for energy storage technologies

Technology	Capital Cost (2012$/kW)	Financing Lifetime (yrs)	Useful Life (yrs)
Pumped Hydro	2,230	30	30
Batteries	4,300	15	15
Flow Batteries	4,300	15	15

The modeling assumptions for hydrogen production and SNG production are described in detail in Technical Appendix Sections 2.2.3 and 2.2.4, respectively. Below, Table 9 shows final product cost ranges, levelized capital costs, and conversion efficiencies for hydrogen and SNG pathways in the model.

Table 9. Renewable electricity-based pipeline gas final product cost, levelized capital cost, and conversion efficiencies in model

Product	Process	Levelized Capital Cost ($/kg-year for hydrogen; $/mmBTU-year for SNG)	Conversion Efficiency	Product Cost Range ($/GJ)
SNG	Electrolysis plus methanation	$7.60-$18.50	52%-63%	$30-$138
Hydrogen	Electrolysis	$0.65-$1.53	65%-77%	$24-$112

The modeling assumptions for biofuels are described in detail in Technical Appendix Section 3. Below, Table 10 shows final product cost ranges, feedstock and conversion cost ranges, and conversion efficiencies for all biomass conversion pathways in the model.

Table 10. Biomass final product cost, feedstock and conversion costs, and conversion efficiencies in model

Product	Process	Feedstock Cost Range ($/ton)	Conversion Cost ($/ton)	Conversion Efficiency (GJ/ton)	Product Cost Range ($/GJ)
Biogas Electricity	Anaerobic digestion	$40-$80	$96	6.5	$21-$27
Pipeline Biogas	Gasification	$40-$80	$155	9.5	$20-$25
Ethanol	Fermentation	$40-$80	$111	6.7	$23-$29
Diesel	Trans-Esterification	$1000	$160	36.4	$32

4 Results

4.1 Summary of results

The two low-carbon scenarios evaluated in this study present unique technology pathways to achieve California's 2050 GHG reduction goals. Each scenario represents a different technically feasible, plausible strategy to decarbonize the state's energy system, resulting in different levels of energy consumption and different mixes of fuels providing energy services. This section presents energy demand by scenario and fuel type in 2050 for the Reference case and the two low-carbon scenarios. Energy system cost projections for each scenario are provided. The cost trajectories are highly uncertain and cannot be interpreted as definitive at this point in time. Each of the low-carbon scenarios shows a similar statewide GHG reduction trajectory.

4.2 Final energy demand

Figure 4 shows final energy demand by fuel type for each scenario in the year 2050. Of note, both the low-carbon scenarios have significantly lower total energy demand than the Reference case due to the impact of energy efficiency and conservation in the low-carbon scenarios.

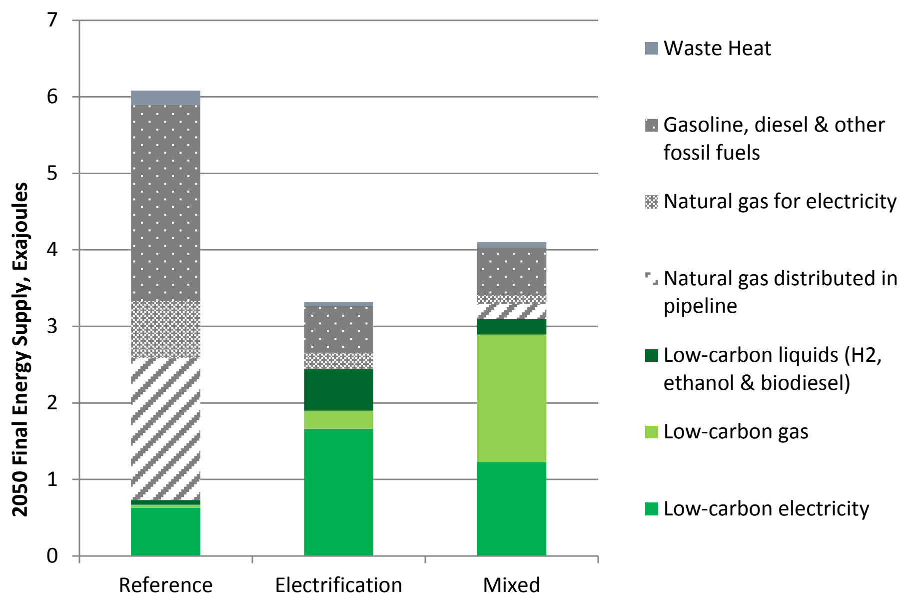


Figure 4. 2050 California economy-wide final energy demand by scenario and fuel type

Final energy consumption in 2050 is lower in the Electrification scenario than the Mixed Scenario due to the higher conversion efficiencies of electric batteries and motors compared to combustion engines and fuel cell vehicles.[18]

Low-carbon electricity is also used as an upstream energy source to produce decarbonized gas and liquid hydrogen, so it plays a larger role in meeting the state's GHG reduction goals in the Mixed scenario than indicated by final energy demand alone. To gain a more complete picture of energy supply by fuel type, the next sections discuss the composition of the pipeline gas by scenario, the sources of electricity in each scenario, and the composition of the

[18] Note that upstream efficiency losses associated with energy production: i.e. P2G methanation, hydrogen production and CCS, do not appear in the final energy supply numbers.

transportation vehicle fleet energy consumption. These results are not meant to be an exhaustive description of each assumption in each sector of the economy, but rather are selected to provide some insights into the biggest differences in energy use between the two low-carbon scenarios and the Reference case.

4.2.1 PIPELINE GAS FINAL ENERGY DEMAND

There are important differences between the two low-carbon scenarios. Pipeline infrastructure continues to be used extensively in the Mixed scenario, with decarbonized gas substituting for the natural gas that would otherwise be used in the pipeline. In the Electrification scenario, pipeline infrastructure is nearly unutilized by 2050. This corresponds to much more widespread electrification of industrial processes, vehicles, space heating, water heating, and cooking. The limited demand for pipeline gas in this scenario is assumed to be met with biogas (Figure 5).

The Mixed scenario includes a higher quantity of biogas, based on the assumption that all of the available sustainably sourced biomass are used to produce biogas. The remaining demand for decarbonized pipeline gas in this scenario is met with a mix of two technologies: 1) SNG produced using P2G methanation with air capture of CO_2[19] and 2) hydrogen produced using electrolysis with renewable electricity.

[19] Methanation using CO_2 capture from seawater is an alternative, potentially more efficient method to creating produced gases that have a net-carbon neutral climate impact.

In the Mixed Scenario, hydrogen use in the gas pipeline is limited by estimates of technical constraints. By 2050, the share of hydrogen gas in the pipeline is assumed to be limited to 20 percent of pipeline volume for reasons of safety as well as compatibility with end-use equipment.[20]

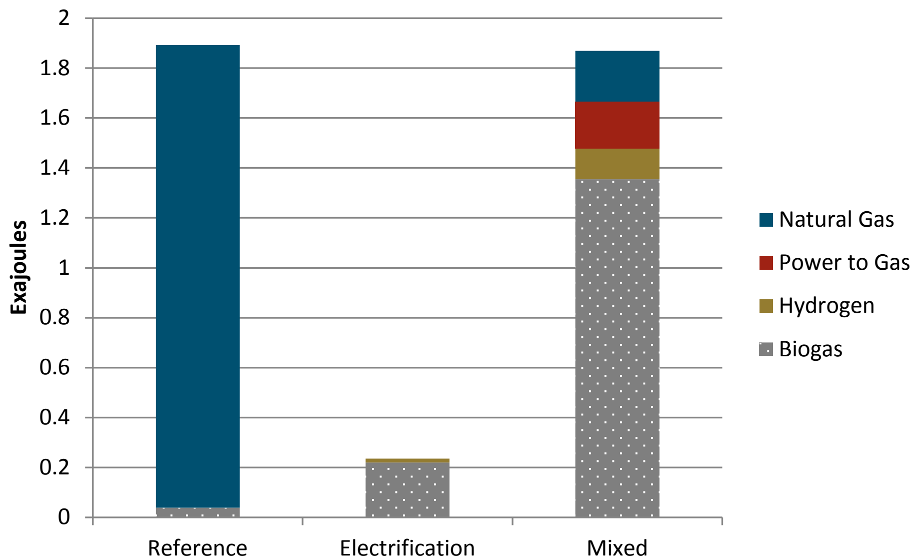


Figure 5. California pipeline gas final energy demand by fuel type by scenario, 2050

4.2.2 ELECTRICITY DEMAND

The 2050 electricity demand in each scenario tells a different part of the energy supply story. In the low-carbon scenarios, 2050 electricity demand is significantly higher in the Reference case due to the impact of electrification, particularly electric LDVs, and the electricity needs associated with P2G and

[20] Note that this limit is only a rough estimate of technical feasibility limits and the actual limit may be lower; additional research is needed to determine an appropriate limit for hydrogen gas in the pipeline.

hydrogen production. The expanding role of the electricity sector in achieving a low-carbon future is evident in each of these scenarios. Figure 6 shows the generation mix by fuel type utilized in each of the scenarios in 2050.

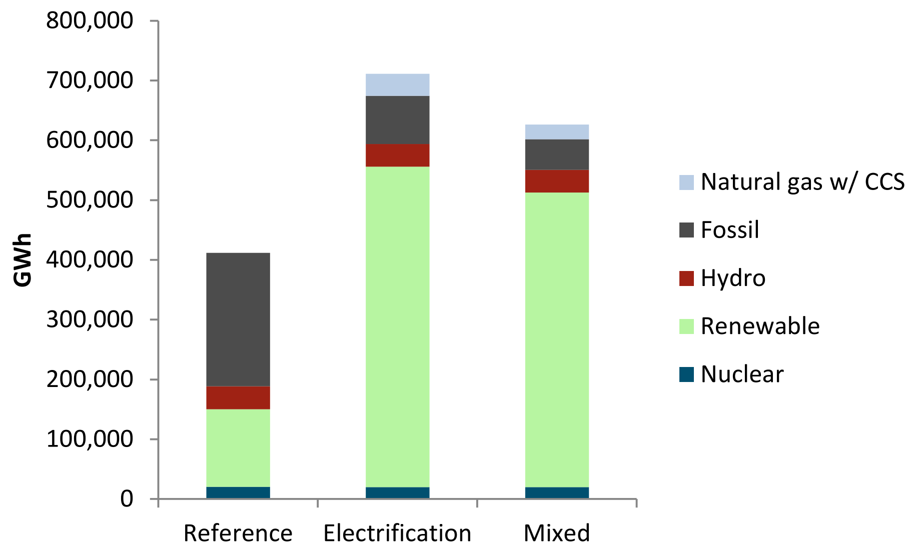


Figure 6. 2050 electricity sector energy demand by scenario and fuel type, GWh

4.2.2.1 Load resource balancing

Both of the low-carbon scenarios reflect a significant increase in intermittent wind and solar PV renewable generation by 2050 (Table 11). This results in new challenges that the grid faces to achieve load-resource balance.

Table 11. Share of 2050 California electricity generation provided by wind and solar PV

	Reference	Low-Carbon Scenarios
Intermittent renewables share of total electricity generation in 2050 (wind and solar PV)	30%	60 -70%

In the model, electricity supply and demand must be equal in each hour of each year. This load-resource balance is achieved using different strategies in each scenario, which contributes to the differences in technology costs and risks. As Table 12 indicates, the Electrification scenario relies heavily on the use of electric energy storage, in the form of flow batteries and pumped hydroelectric storage resources, while the Mixed scenario relies more heavily on P2G production as a load-following resource. Natural gas with CCS is assumed to be a load-following resource in both scenarios. Furthermore, both scenarios assume electric vehicles can provide limited load-resource balancing services through flexible charging of EVs over a 24-hour period, and that hydrogen production for fuel cell vehicles can be operated as a fully-dispatchable, flexible load.

Table 12. 2050 Load Resource Balancing Assumptions by Scenario

Load-resource balancing tool	Electrification	Mixed
Electric energy storage capacity	**20 GW** 75% 6-hour flow batteries, 25% 12-hour pumped hydro energy storage	**5 GW** 100% 12-hour pumped hydro energy storage
P2G capacity	**None**	**40 GW** P2G production cycles on during the daylight hours to utilize solar generation and cycles off at night, significant variation in production by season for load balancing
Electric vehicles & other flexible loads	**40%** of electric vehicle loads are considered "flexible" in both scenarios and can be shifted within a 24-hour period. Vehicle batteries are not assumed to provide power back onto the grid. Certain thermal electric commercial and residential end uses are also assumed to provide limited amounts of flexible loads to the grid. In both scenarios, hydrogen production is assumed to be a fully dispatchable, flexible load.	

4.2.3 ON-ROAD VEHICLE ENERGY CONSUMPTION BY FUEL TYPE

The decarbonization strategy pursed in the transportation sector differs by scenario, as illustrated in Figure 7 (LDV vehicle energy use) and Figure 8 (HDV energy use). Both of the low-carbon scenarios assume a significant reduction in VMT and vehicle efficiency improvements in the LDV fleet compared to the Reference scenario. This leads to a significant reduction in total energy demand by LDVs by 2050 in these scenarios. Among the HDV vehicle fleet, VMT reductions and vehicle efficiency improvements are assumed to be more difficult to achieve than in the LDV fleet. Furthermore, the Mixed scenario relies on a high proportion of fuel cell vehicles using hydrogen or liquefied pipeline gas, which have less efficient energy conversion processes than conventional diesel engines, leading to higher energy demand. As a result, the HDV sector does not show a significant reduction in energy consumption by 2050 relative to the Reference case, although total carbon emissions are significantly lower.

Electricity is the largest source of fuel for the transportation sector among LDVs in both the Electrification and the Mixed scenarios. The HDV fleet is harder to electrify, so the Electrification scenario assumes HDV energy demand is largely met with hydrogen fuel and fuel cells. In the Mixed scenario, the majority of HDV energy demand is assumed to be met with liquefied pipeline gas (an equivalent to decarbonized LPG), with some compressed pipeline gas (the equivalent to decarbonized compressed natural gas), electrification and hydrogen fuel cell vehicles.

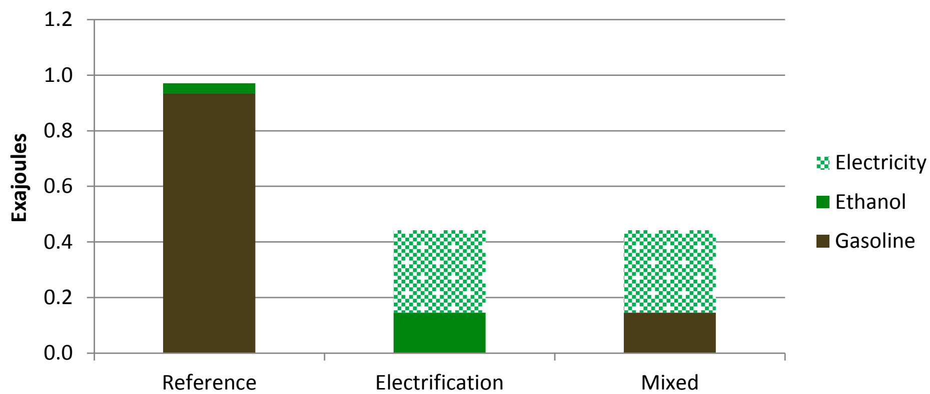


Figure 7. 2050 LDV energy share by fuel type by scenario

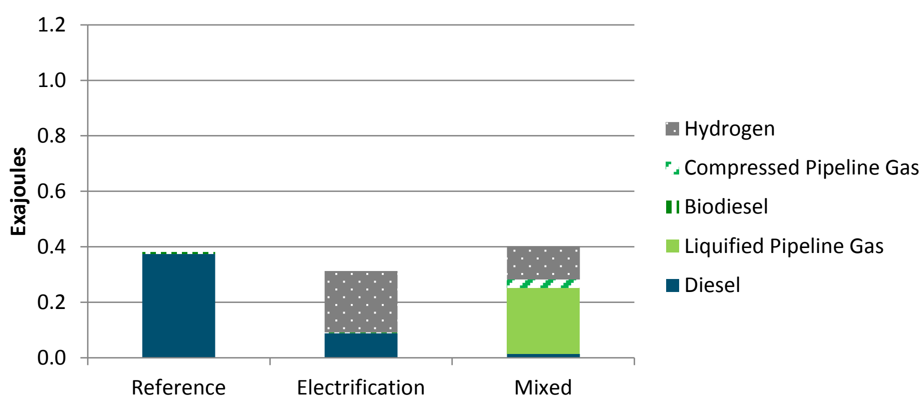


Figure 8. 2050 HDV energy share by fuel type by scenario

4.3 Greenhouse gas emissions

The Reference case shows GHG emissions that are relatively flat through 2030 before slightly increasing in the outer years through 2050. This increase occurs because population growth and increasing energy demand overwhelm the emissions savings generated by current policies. The result is a 9 percent increase in Reference case emissions relative to 1990 levels by 2050.

The GHG emissions trajectories for the two low-carbon scenarios evaluated in this report are essentially the same. Both scenarios achieve the target of 80% reduction in GHG emissions by 2050 relative to 1990 levels, and both scenarios reflect a similar, approximately straight-line trajectory of emissions reductions between current emissions levels and 2050.

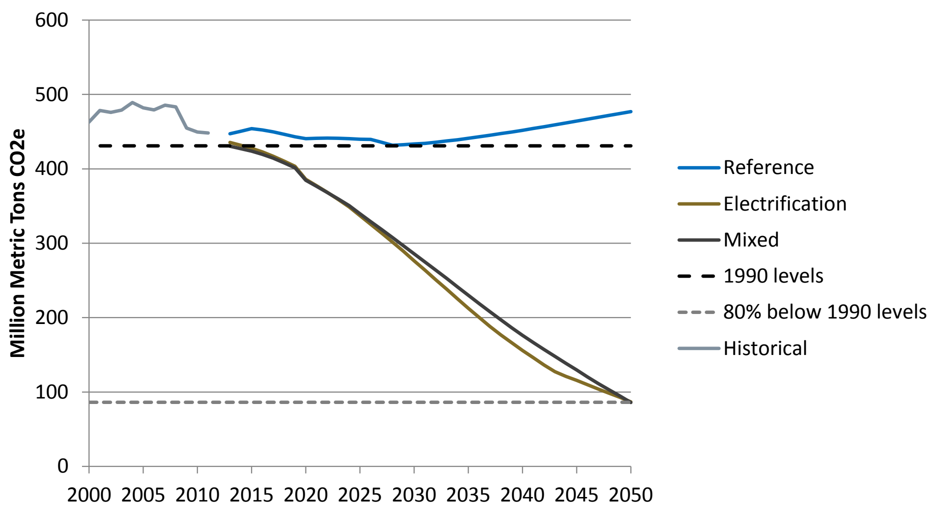


Figure 9. California GHG emissions by scenario, including historical emissions and policy targets (2000 – 2050)

4.4 Energy system cost comparison

The total energy system cost of each of the scenarios analyzed is one metric by which to evaluate different GHG scenarios. Total energy system cost is defined here as the annual statewide cost of fossil fuels and biofuels, plus the levelized cost of electricity and natural gas infrastructure, plus the cost of most energy-consuming customer products (e.g., clean vehicles in the transportation sector and energy efficiency and fuel-switching equipment in the buildings sector). The total energy system cost is calculated on a levelized basis in each analysis year, from 2015 – 2050. Further detail on cost assumptions and how costs are treated in the model is provided in the Technical Appendix.

While the Reference case is the lowest total cost scenario from an energy system perspective, it also does not succeed in meeting the state's GHG reduction goals. Of the two low-carbon scenarios, the Mixed scenario has approximately 10 percent lower cost than the Electrification scenario in 2050 using our base case assumptions. This difference is well within the range of uncertainty of projecting technology costs to 2050, and either scenario could be lower cost.

It is, however, useful to examine the differences in base case scenario costs that result from the modeling assumptions made in this analysis to identify the key drivers. Using the base case assumptions, the Mixed case results in lower total energy system costs in 2050 than the Electrification scenario for two main reasons (Figure 10). First, using the assumptions in this study, adding decarbonized gas in the Mixed case has a lower cost than adding the low-carbon electricity and end-use equipment necessary to electrify certain end-uses in the Electrification case. Therefore, the reduction of electricity-related capital costs between the Electrification and the Mixed scenario shown in Figure 10 is greater than the increase in pipeline gas capital costs and biogas fuel costs between these scenarios. Second, seasonal electricity storage needs are lower in the Mixed scenario than in the Electrification scenario. As a result, the electricity storage that is built in the Mixed scenario is utilized at a higher capacity factor than the electricity storage in the Electrification scenario. This means that the unit cost of electricity storage ($/MWh) is higher in the Electrification scenario than in the Mixed scenario.

In order to evaluate the range of uncertainty, we define high and low cost Scenarios for the key input assumptions. These do not reflect the range of all of the uncertainties in energy demands, population, or other key drivers embedded in the analysis, but serve to provide a boundary of possible high and low total costs given the same assumptions across the three cases. We then evaluate the total costs of each of the cases; Reference, Electrification Case, and Mixed Case with each cost scenario. Table 13, below, shows the range of the cost uncertainties in the analysis. Scenario 1 is purposefully designed to advantage the Mixed Case, and Scenario 2 is designed to advantage the Electrification Case.

Table 13 Cost sensitivity parameters

Cost Assumption	Scenario 1	Scenario 2
Renewable generation capital	+25%	-25%
Electrolysis capital equipment	-50%	+50%
SNG capital equipment	-50%	+50%
Fuel cell HDVs	+50%	-50%
Building electrification cost[21]	+50%	-50%
Natural Gas Costs	-50%	+50%
Other Fossil Fuel Costs	+50%	-50%
Electricity storage costs	+50%	-50%
Biomass Availability[22]	+0%	-50%

The 2050 cost results shown below indicate that there are conditions under which either case is preferable from a cost standpoint. Given that, and given the

[21] Costs of electrified water and space heating equipment
[22] Biomass is replaced with addition P2G to maintain emissions levels +- 5MMT from base case.

additional uncertainties not analyzed in terms of other technology costs, energy demand drivers, etc., the preference for pursuing one mitigation case over the other should come down to other factors than narrow cost advantages displayed over these long term forecasts.

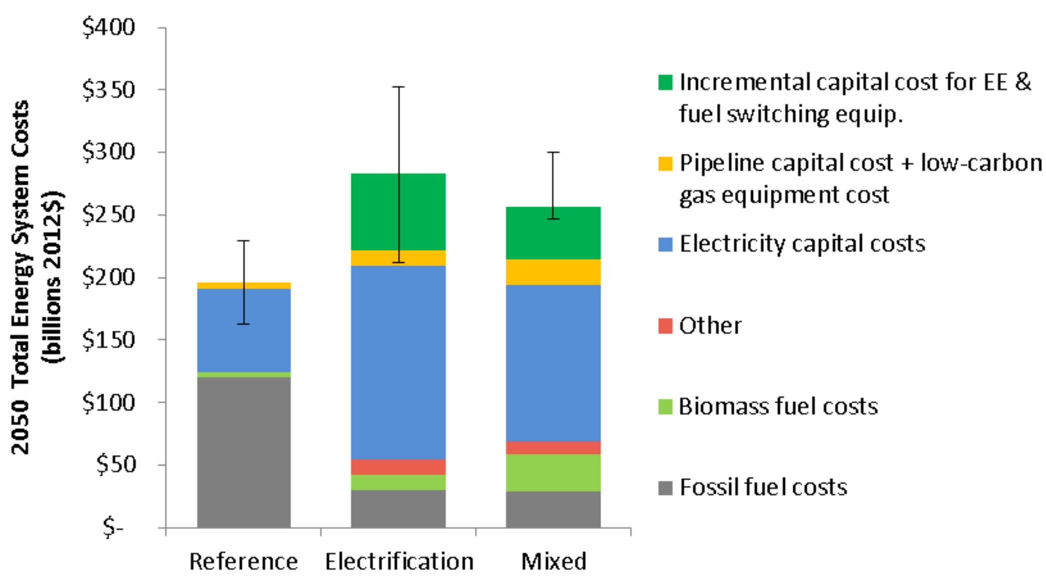


Figure 10. 2050 total energy system cost by scenario (levelized cost of fuel and levelized capital cost of energy infrastructure)

Figure 11, below, shows the base case total levelized energy system capital investment and fuel costs for each scenario along with the uncertainty range. Given the uncertainties associated with forecasting technology and commodity costs out to 2050, a difference in costs of approximately 10% ($27 billion) between the two scenarios is not definitive.

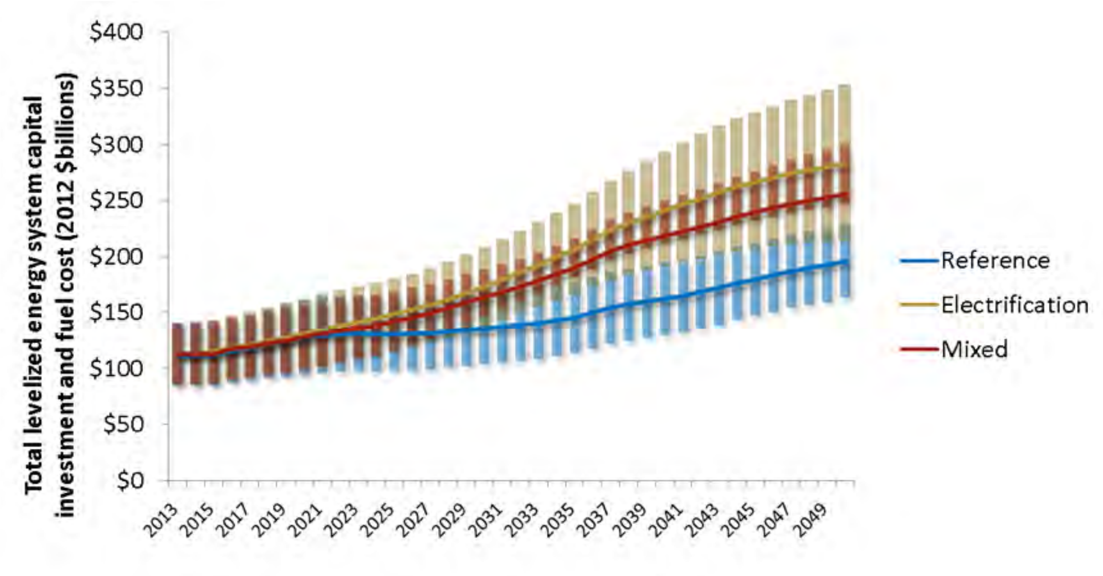


Figure 11. Total energy system cost by scenario, 2013 – 2050 (levelized cost of fuel and levelized capital cost of energy infrastructure, billions, 2012$)

Figure 12, below, shows total electricity sector costs on an annualized basis, or equivalently, the statewide electricity sector revenue requirement, in 2050. Electricity costs are higher in the Electrification scenario both because total electricity demand is higher, and because the unit cost of electricity is higher. The cost of energy storage is highest in the Electrification scenario because more storage is needed to balance intermittent renewables, and because batteries are the primary means of storage. In the Mixed scenario, less energy storage is needed because the production of decarbonized gases (hydrogen and SNG) is dispatched to balance the grid, and because gas is a more cost-effective form of seasonal energy storage, given the assumptions here, than batteries. Again, however, cost forecasts for 2050 are highly uncertain and should be interpreted with caution.

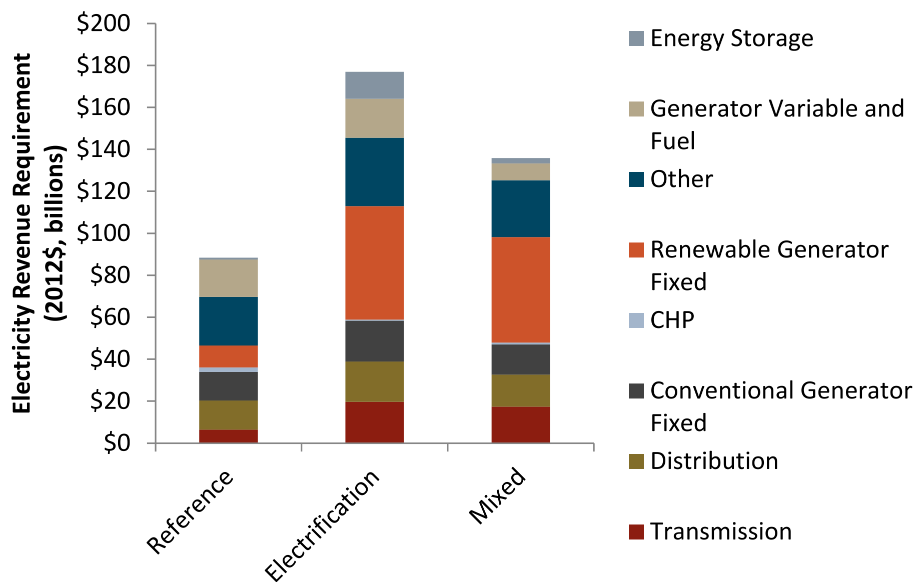


Figure 12. 2050 California total electricity sector revenue requirement by component and scenario (billions, 2012$)

5 Discussion & Conclusions

California is committed to deeply reducing CO_2 and other GHG emissions across all sectors over the next several decades, as well as to sharply reducing ground-level ozone and particulate matter to protect public health. Both of these policies imply a dramatic transition of California's economy away from fossil fuel combustion as we know it, and indeed this transition is already underway. In some places where coal is the dominant form of energy supply, natural gas is often seen as a key transition fuel to a lower carbon system. In California, however, natural gas is the main incumbent fossil fuel in electricity generation, the building sector, and many industries, and is therefore the target of transition to a lower carbon economy rather than its vehicle; the problem of methane leakage in the natural gas production and supply chain, though not modeled in this analysis, only increases the policy pressure to hasten this transition.

It is possible for SCG and other gas distribution companies to be a contributor rather than an impediment to California's transition to a low carbon economy. This path of decarbonizing pipeline gas will require a major technological transformation in the coming years. On the demand side, the transition requires reducing demand in many existing applications and improving combustion processes to increase efficiency. On the supply side, it requires developing decarbonized alternatives to conventional natural gas for delivering energy to end uses.

This study examined the role of gas fuels in California's energy supply from 2013 to 2050, using a bottom-up model of the California economy and its energy systems. We examined the feasibility andcost associated with two distinct technology pathways for achieving the state's 2050 GHG targets: (1) Electrification, and (2) Mixed (electricity and decarbonized gas).

To date, much of the literature on low-carbon strategies and policy strategies for achieving deep reductions in GHG emissions in California by 2050 has focused on extensive electrification. This study's results support our prior conclusions that the electricity sector must play an expanded and important role in achieving a low-carbon future in California. In both of the low-carbon scenarios, the need for low-carbon electricity increases significantly beyond the Reference case level: to power electric vehicles, electrification in buildings and as a fuel to produce decarbonized gases. We also demonstrate that, under reasonable assumptions, there are feasible technology pathways where gas continues to play an important role in California's energy supply.

The costs of technologies in the 2050 timeframe are highly uncertain, making it impossible to reach a definitive conclusion as to which of the low-carbon pathways evaluated here would be the lowest cost. However, we show that the Mixed scenario, where decarbonized gas meets existing natural gas market share in residential, commercial, and industrial end uses, and is used to power the heavy-duty vehicle fleet, could potentially be higher or lower cost depending on the technology and market transformation. A key driver of this result is the ability to use the existing gas pipeline distribution network to store and distribute decarbonized gas, and to use the production of decarbonized gas as a means to integrate intermittent renewable energy production. Excess renewable energy in the middle of the day is absorbed by P2G production of SNG and hydrogen production in the Mixed scenario. The Electrification scenario, which does not utilize the P2G technology to produce decarbonized gas, decreases gas pipeline use out to 2050 (shown for SCG, Figure 13) and requires more relatively high-cost, long-duration batteries for energy storage.[23]

[23] In Figure 14 the slight increase in natural gas used for electricity generation observed in 2020 is due to an existing coal generation contract being partially replaced with natural gas generation.

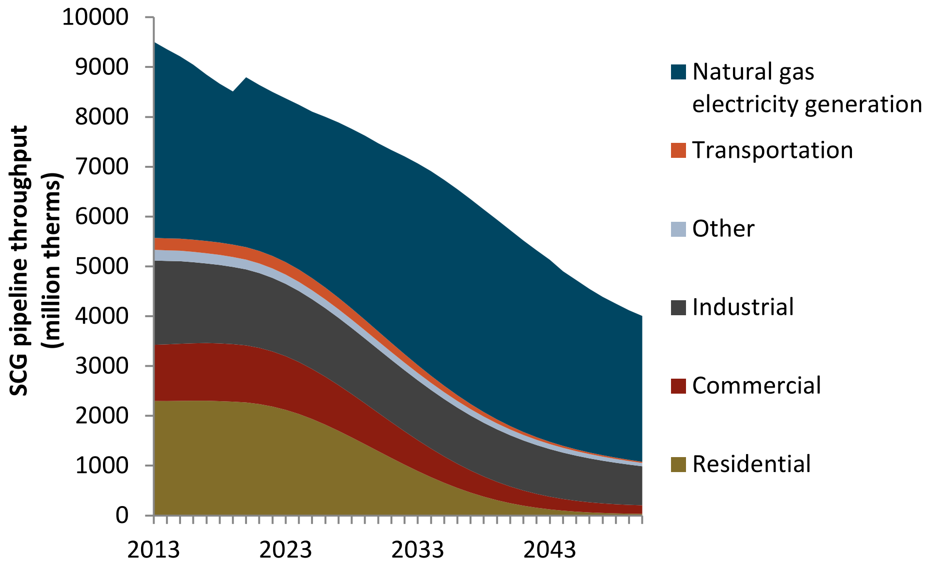


Figure 13. Electrification Scenario, SCG pipeline gas throughput (2013 – 2050)

Strategic use of decarbonized gas would additionally help to overcome four potential obstacles in California's transition to a decarbonized energy system.

First, a number of current uses of natural gas and oil are difficult to electrify. These include certain industrial processes such as process heat, HDVs and certain end uses in the residential and commercial sectors such as cooking, where customers have historically preferred gas fuels. Using decarbonized gas for these end uses could avoid the need for economically and politically costly electrification strategies.

Second, under a high renewable generation future, long-term, seasonal load balancing may be needed in addition to daily load balancing. However, meeting these seasonal balancing needs under the Electrification scenario requires uncertain technical progress in energy storage. Using the production of decarbonized gas to provide daily and seasonal load balancing services may be a more realistic and cost-effective strategy than flexible loads and long-duration batteries for electricity storage.

Third, using decarbonized gas takes advantage of the state's existing gas pipeline distribution system, and reduces the need for other low-carbon energy infrastructure such as transmission lines or a dedicated hydrogen pipeline network.

Fourth, and finally, the Mixed scenario, by employing a range of energy technologies, including electricity and decarbonized gas technologies, diversifies the risk that any one particular technology may not achieve commercial successes.

All of the decarbonized gas energy carriers examined in this analysis rely on century-old conversion processes; none require fusion-like innovations in science. However, these conversion processes — anaerobic digestion, gasification, electrolysis, and methanation — require improvements in efficiency and reductions in cost to be more competitive. Furthermore, existing pipelines were not designed to transport hydrogen, and innovations in pipeline materials and operations would be needed to accommodate a changing gas blend.

Sustainably-sourced biomass feedstock availability is another large source of uncertainty in both of the low-carbon strategies evaluated here. In the Mixed scenario, biogas plays a particularly important role in achieving the GHG emission target. In the Electrification scenario, biomass is used to produce low-carbon electricity. However, biomass feedstocks are constrained by competing uses with energy supply, including food, fodder and fiber. The amount of biomass resources available as a feedstock for fuels, or for biogas production specifically, will depend on innovations in biosciences, biomass resource management, and supply chains. None of the above three challenges — conversion technology efficiency and cost, pipeline transport limits, and biomass feedstock availability — is inherently insurmountable. For decarbonized gas to begin to play an expanded role in California's energy supply in the coming decades, however, a program of RD&D to overcome these challenges would need to begin very soon. This report identifies research priorities with near-term, medium-term and long-term payoff.

As a whole, California policy currently explicitly encourages the production of low-carbon electricity, through initiatives such as the RPS, and the production of decarbonized transportation fuels, through initiatives such as the LCFS. Biogas from landfill capture and dairy farms are encouraged, however, the state does not currently have a comprehensive policy around decarbonized gas production and distribution. This analysis has demonstrated that a technologically diverse, "mixed" strategy of electrification and decarbonized gas may be a promising route to explore on the pathway to a long-term, low-carbon future in California.

Appendix

Table of Contents

1 Demand Projections

1.1 Stock demand projections

The basic stock roll-over methodology is used both in the development of our demand unit projections as well as our supply unit stock analysis. For example, we use the stock roll-over to project square feet of indoor space and we also use a stock roll-over to estimate the stock efficiency of air conditioners used to cool that indoor space. The basic mechanics of stock roll-over are used throughout the model in estimating basic energy service demands, calculating current and future baseline stock efficiencies, and calculating the impacts of our mitigation measures. Our stock roll-over modeling approach necessitated inputs concerning the initial composition of stocks (vintage, fuel type, historical efficiencies, etc.) as well as estimates of the useful lives of each stock type.

Stock roll-overs are determined by technology useful lives, scenario-defined sales penetration rates, and the shapes of those sales penetrations (S-curves that might more closely mirror market adoption; and linear adoptions that may more accurately reflect policy instruments). Given that the model is designed to provide information on the technologies and policies necessary to reach long-term carbon goals, these are not forecasts: they are not dynamically adjusted for consumer preference, energy costs, payback, etc. that might inform actual technological uptake.

We model a stock roll-over at the technology level for a limited set of subsectors in which homogeneous supply units could be determined (i.e. residential water heating). Figure 1 shows an example stock roll-over of the residential water heating stock to 2050. This example shows the water heating stock rolling over to high efficiency devices – i.e. standard gas tank water heaters roll over to condensing and tankless gas water heaters. Stock roll-overs like these are then used to project energy demand as well as costs using the methodology described in section 1.1.5.

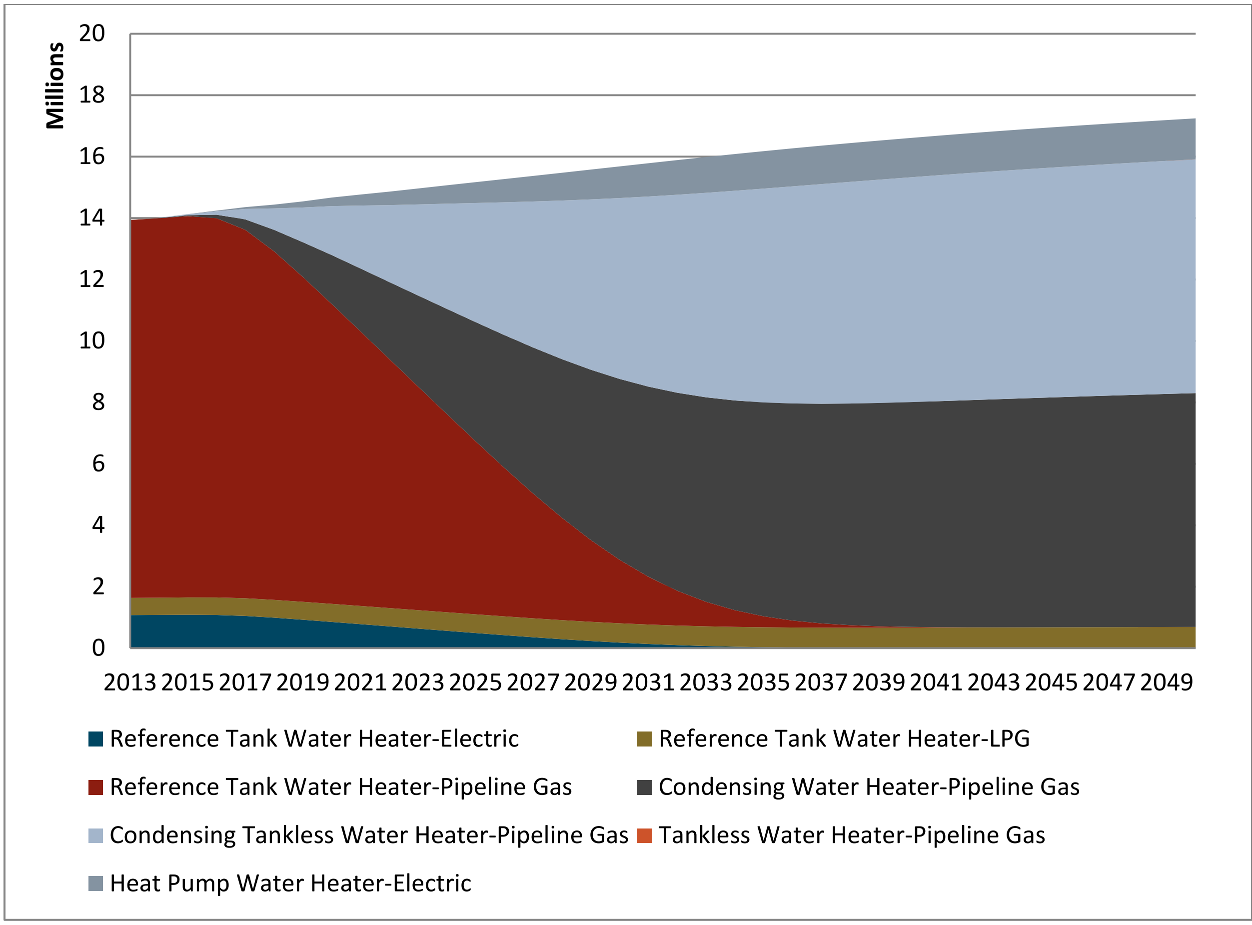


Figure 1. Residential water heater example stock roll-over

1.1.1 STOCK ROLL-OVER: TECHNOLOGIES

For those subsectors measured at the technology level, a stock roll-over is employed to model energy demand under different scenarios of policy and technological emphasis. This influences the stock composition as shown above in Figure 1. These stocks therefore influence energy demandand costs as a function of defined technology characteristics.

Technology Characteristic	Description
Primary Energy Type	Determines primary final energy type used by demand stock (i.e. gasoline, electricity, etc.)
Secondary Energy Type	Determines final energy type used by demand stock (i.e. gasoline, electricity, etc.)
Utility Factor (Transportation Only)	Allocates share of energy use between primary energy type and secondary energy type. Used for dual-fuel applications like plug-in hybrid electric vehicles.
Useful Life	Determines stock decay function of technology units
Initial Unit Costs	Starting y-coordinate (cost) on technology cost function
Initial Unit Cost Year	Starting x-coordinate (year) on cost estimation function
Forecast Unit Costs	Ending y-coordinate (cost) on technology cost function
Forecast Unit Cost Year	Ending x-coordinate (year) on cost estimation function
Efficiency	Normalized, or unitless, conversion of service demand to energy use

1.1.2 STOCK ROLL-OVER: DECAY AND REPLACEMENT

We model the decay of technology based on Poisson distributions with mean values equal to our assumed EULs. When a technology decays, it is replaced at a rate determined by scenario inputs that influence technology uptake rates and sales penetration. This determines an overall stock composition by technology and vintage. The figure below shows this for gasoline light duty vehicles (LDVs) as they are gradually phased out in an example scenario.

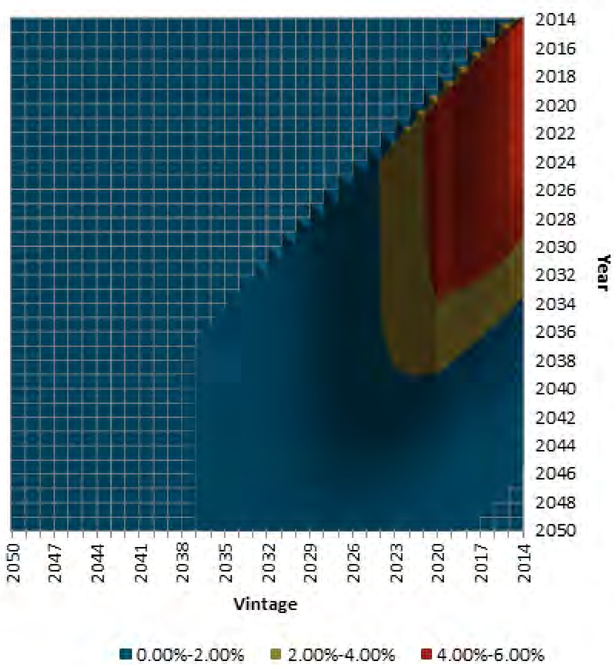


Figure 2. Example gasoline LDV stock composition

1.1.3 STOCK ROLL-OVER: ENERGY

Final energy demand by year for each subsector is determined by the technology composition of each stock. Each technology has a specified energy type and efficiency (by technology vintage). The percentage of the subsector service demand that is met by each technology and vintage combination is divided by the efficiency of the technology and summed over the applicable energy type. This converts our service demand projections into energy demand.

Equation 1.

$$\sum_t \boldsymbol{Stock}\,\% * \boldsymbol{Service\ Demand} * \boldsymbol{Efficiency}$$

1.1.4 STOCK ROLL-OVER: GHG EMISSIONS

To determine GHG emissions from the stock in each subsector, we multiply the energy demand in each subsector for each final energy type by the energy type's GHG emissions rate. The methodology for determining the emissions rate of each final energy type is described in detail in Section 2.

Equation 4.

$$\sum_t \boldsymbol{Stock}\,\% * \boldsymbol{Energy\ Demand} * \boldsymbol{GHG\ Emissions\ Rate}$$

1.1.5 STOCK ROLL-OVER: COSTS

Stock roll-over measure costs are calculated as a function of the levelized incremental cost of the replacement technology over the cost of the reference technology that would otherwise have been installed. These incremental cost trajectories are unique for each replacement year, reflecting unique cost trajectories for every technology by year.

$$\boldsymbol{Stock\ Roll-over\ Measure\ Costs} = \boldsymbol{Replacement\ Technology\ Cost}\ (\$/yr) - \boldsymbol{Replaced\ Technology\ Cost}(\$/yr) * \boldsymbol{Technology\ Units}$$

This methodology is employed for all stock roll-overs where incremental measure costs could be determined. For some stock roll-overs where it was not possible to develop technology level cost estimates, cost differences are primarily driven by the technology's energy types. An example is shown below for residential water heaters. As advanced technologies are rolled into the stock, the incremental measure costs rise; as the incremental costs of those technologies decline, we see a decrease in the total measure costs despite an increase in the technology penetration. The energy savings of these advanced technologies are not accounted for in the figure and represent the benefit of these incremental capital costs.

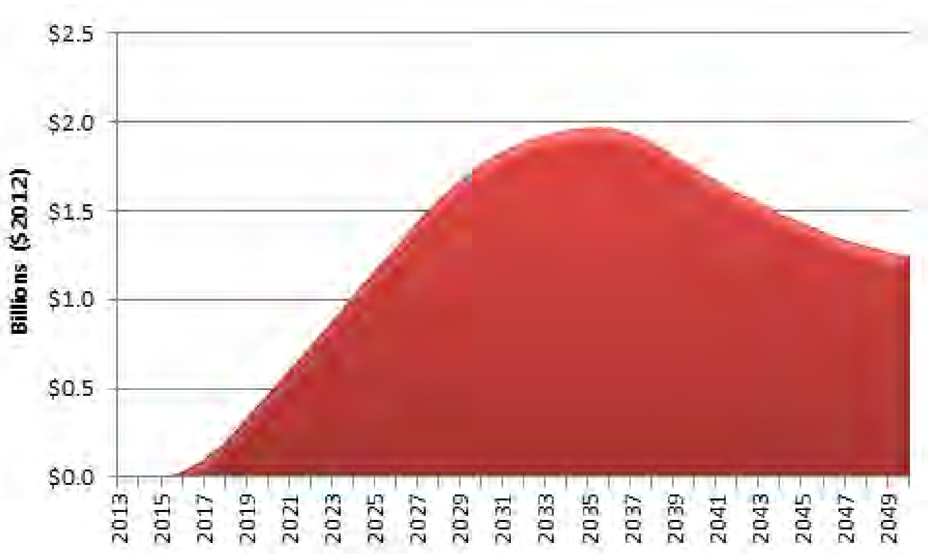


Figure 3. Residential water heater example stock roll-over measure costs

1.2 Regression demand projections

We utilize a linear regression approach to project the industrial energy demand for subsectors not able to be represented by homogenous equipment level stocks. Equation 1 shows an example regression function (GJ/year) for pipeline gas use in the chemical manufacturing subsector.

Equation 1.

Where *Year= Year-1990*

$$(374.2\ \boldsymbol{Mtherms} + (\boldsymbol{Year} * 4.5\ \boldsymbol{Mtherms})$$

1.2.1 SUBSECTOR GHG EMISSIONS

The equation below is used to calculate subsector GHG emissions as a function of final energy demand and GHG emissions factors calculated endogenously on an annual basis in the model.

Equation 2

$$\boldsymbol{GHG\ Emissions}[\boldsymbol{y},\boldsymbol{e}] = \boldsymbol{Final\ Energy\ Demand}[\boldsymbol{e}] * \boldsymbol{GHG\ Emissions\ Factor}\ [\boldsymbol{y},\boldsymbol{e}]$$

1.2.2 SUBSECTOR COSTS

Subsector costs include the costs of fuel switching measures as well as energy efficiency measures which are calculated on a levelized basis. These levelized costs represent any incremental costs of end-use equipment for fuel switching or efficiency purchases.

Equation 3

$$\boldsymbol{Fuel\ Switching\ Costs}[\boldsymbol{y}] = \boldsymbol{Levelized\ Cost} * \boldsymbol{Replacement\ Energy\ Demand}[\boldsymbol{y}]$$ [1]

Equation 4

$$\boldsymbol{Energy\ Efficiency\ Costs}[\boldsymbol{y}] = \boldsymbol{Levelized\ Cost} * \boldsymbol{Energy\ Savings}[\boldsymbol{y}]$$

---

[1] Replacement energy demand represents the demand for the new energy (i.e. fuel switching to electricity calculates the costs as a function of the new electricity demand).

Equation 5

$$\boldsymbol{Total\ Subsector\ Costs}[\boldsymbol{y}] = \boldsymbol{Energy\ Efficiency\ Costs}[\boldsymbol{y}] + \boldsymbol{Fuel\ Switching\ Costs}[\boldsymbol{y}]$$

2 Energy Supply Modeling

The final energy demand projections developed in the previous section are used to project energy supply stocks and final delivered energy prices and emissions. This makes our supply and demand dynamic and allows us to determine inflection points for emissions reductions and costs for each final energy type (i.e. electricity, pipeline gas, etc.) as well as potential synergies and opportunities for emissions reduction using a variety of different decarbonization strategies. We model the twelve distinct final energy types listed in Table 1 that can be broadly categorized as electricity, pipeline gas, liquid fuels, and other. For each final energy type, we model different primary energy sources and conversion processes. Additionally, we model delivery costs for some final energy types. The methodology for calculating the costs and emissions of these supply choices is modeled in this section.

Table 1. Final energy types

Energy Type	Energy Type Category
Electricity	Electricity
Pipeline Gas	Pipeline Gas
Liquefied Pipeline Gas (LNG)	
Compressed Pipeline Gas (CNG)	
Gasoline	Liquid Fuels
Diesel	
Kerosene-Jet Fuel	
Hydrogen	
Refinery and Process Gas	Other
Coke	
LPG	
Waste Heat	

2.1 Electricity

The electricity module simulates the planning, operations, cost, and emissions of electricity generation throughout the state of California. This module interacts with each of the energy demand modules so that the electricity system responds in each year to the electricity demands calculated for each subsector. Both planning and operations of the electricity system rely not only on the total electric energy demand, but also on the peak power demand experienced by the system, so the module includes functionality to approximate the load shape from the annual electric energy demand. Interactions between the load shaping, generation planning, system operations, and revenue requirement modules are summarized in Figure 4 and each module is described in this section.

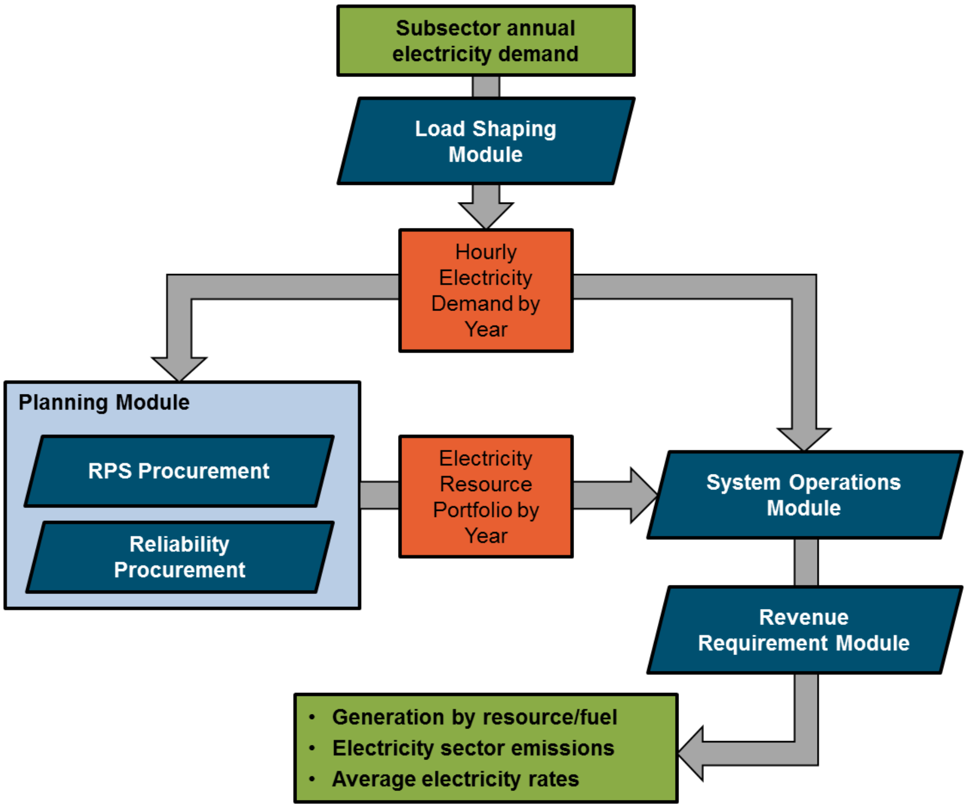


Figure 4. Summary of electricity module

2.1.1 LOAD SHAPING

Single year hourly load shapes were derived for 18 sectors/subsectors based on available hourly load and weather data. For each subsector, shapes were obtained from publicly available data sources, including DEER2008, DEER 2011, CEUS, BeOpt, and PG&E Static and Dynamic load shapes. For each temperature-sensitive subsector, corresponding temperature data was obtained from each of the 16 climate zones. The shapes obtained for this analysis and the corresponding weather year or weather data source are listed in Table 2.

Table 2. Input load shapes and sources

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
1	Residential Water Heating	DEER2008		PG&E	2008 Title 24
2	Residential Water Heating	DEER2008		SCE	2008 Title 24
3	Residential Water Heating	DEER2008		SDG&E	2008 Title 24
4	Residential Space Cooling	DEER2008		PG&E	2008 Title 24
5	Residential Space Cooling	DEER2008		SCE	2008 Title 24
6	Residential Space Cooling	DEER2008		SDG&E	2008 Title 24
7	Residential Space Cooling	DEER2011	HVAC_Eff_AC	PG&E	2008 Title 24
8	Residential Space Cooling	DEER2011	HVAC_Eff_AC	SCE	2008 Title 24
9	Residential Space Cooling	DEER2011	HVAC_Eff_AC	SDG&E	2008 Title 24
10	Residential Lighting	DEER2011	Indoor_CFL_Ltg	PG&E	2008 Title 24
11	Residential Lighting	DEER2011	Indoor_CFL_Ltg	SCE	2008 Title 24
12	Residential Lighting	DEER2011	Indoor_CFL_Ltg	SDG&E	2008 Title 24

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
13	Residential Clothes Washing	DEER2011	ClothesWasher	PG&E	2008 Title 24
14	Residential Clothes Washing	DEER2011	ClothesWasher	SCE	2008 Title 24
15	Residential Clothes Washing	DEER2011	ClothesWasher	SDG&E	2008 Title 24
16	Residential Dishwashing	DEER2011	Dishwasher	PG&E	2008 Title 24
17	Residential Dishwashing	DEER2011	Dishwasher	SCE	2008 Title 24
18	Residential Dishwashing	DEER2011	Dishwasher	SDG&E	2008 Title 24
19	Residential Refrigeration	DEER2011	RefgFrzr_HighEff	PG&E	2008 Title 24
20	Residential Refrigeration	DEER2011	RefgFrzr_HighEff	SCE	2008 Title 24
21	Residential Refrigeration	DEER2011	RefgFrzr_Recyc-UnConditioned	PG&E	2008 Title 24
22	Residential Refrigeration	DEER2011	RefgFrzr_Recyc-UnConditioned	SCE	2008 Title 24
23	Residential Refrigeration	DEER2011	RefgFrzr_Recyc-UnConditioned	SDG&E	2008 Title 24
24	Residential Clothes Drying	DEER2008		PG&E	2008 Title 24
25	Residential Cooking	BEopt		CZ3	BEopt

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
26	Residential Other	BEopt		CZ3	BEopt
27	Residential Space Heating	BEopt		CZ3	BEopt
28	Residential Space Heating	BEopt		CZ6	BEopt
29	Residential Space Heating	BEopt		CZ10	BEopt
30	Residential Space Heating	BEopt		CZ12	BEopt
31	Commercial Water Heating	DEER2008		PG&E	2008 Title 24
32	Commercial Water Heating	DEER2008		SCE	2008 Title 24
33	Commercial Water Heating	DEER2008		SDG&E	2008 Title 24
34	Commercial Space Heating	CEUS			Historical - 2002
35	Commercial Space Cooling	DEER2011	HVAC_Chillers	PG&E	2008 Title 24
36	Commercial Space Cooling	DEER2011	HVAC_Split-Package_AC	PG&E	2008 Title 24
37	Commercial Space Cooling	DEER2011	HVAC_Chillers	SCE	2008 Title 24
38	Commercial Space Cooling	DEER2011	HVAC_Split-Package_AC	SCE	2008 Title 24

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
39	Commercial Space Cooling	DEER2011	HVAC_Chillers	SDG&E	2008 Title 24
40	Commercial Space Cooling	DEER2011	HVAC_Split-Package_AC	SDG&E	2008 Title 24
41	Commercial Lighting	CEUS			Historical - 2002
42	Commercial Lighting	DEER2011	Indoor_CFL_Ltg	PG&E	2008 Title 24
43	Commercial Lighting	DEER2011	Indoor_Non-CFL_Ltg	PG&E	2008 Title 24
44	Commercial Lighting	DEER2011	Indoor_CFL_Ltg	SCE	2008 Title 24
45	Commercial Lighting	DEER2011	Indoor_Non-CFL_Ltg	SCE	2008 Title 24
46	Commercial Lighting	DEER2011	Indoor_CFL_Ltg	SDG&E	2008 Title 24
47	Commercial Lighting	DEER2011	Indoor_Non-CFL_Ltg	SDG&E	2008 Title 24
48	Commercial Cooking	CEUS			Historical - 2002
49	Streetlights	PG&E Static	LS1	PG&E	Historical - 2010
50	Agriculture	PG&E Static	AG1A	PG&E	Historical - 2010
51	Agriculture	PG&E Static	AG1B	PG&E	Historical - 2010

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
52	Agriculture	PG&E Static	AG4A	PG&E	Historical - 2010
53	Agriculture	PG&E Static	AG4B	PG&E	Historical - 2010
54	Agriculture	PG&E Static	AG5A	PG&E	Historical - 2010
55	Agriculture	PG&E Static	AG5B	PG&E	Historical - 2010
56	Agriculture	PG&E Static	AGVA	PG&E	Historical - 2010
57	Agriculture	PG&E Static	AGRA	PG&E	Historical - 2010
58	Industrial	PG&E Dynamic	A6	PG&E	Historical - 2010
59	Industrial	PG&E Dynamic	E19P	PG&E	Historical - 2010
60	Industrial	PG&E Dynamic	E19V	PG&E	Historical - 2010
61	Industrial	PG&E Dynamic	E20P	PG&E	Historical - 2010

2.1.1.1 Load shaping methodology

The load shaping module first requires normalization of each input load shape from its corresponding weather year to the simulation year. This process occurs in two steps. First, the load shape is approximated as a linear combination of the hourly temperature in each climate zone, the hourly temperature in each climate zone squared, and a constant. This regression is performed separately for weekdays and weekends/holidays to differentiate between behavioral modes on these days.

$$\boldsymbol{x_i} \approx \sum_{\boldsymbol{k \in CZ}} \left[\boldsymbol{a_{ik} w_{ik}^2} + \boldsymbol{b_{ik} w_{ik}}\right] + \boldsymbol{c_{ik}}$$

where x_i is the input load shape, w_{ik} is the hourly temperature in climate zone k in the weather year associated with the input load shape, and a_{ik}, b_{ik}, and c_{ik} are constants. Next, the hourly temperature data for the simulation year in PATHWAYS is used to transform the input load shapes into the same weather year. This process also occurs separately for weekdays and weekends/holidays.

$$\boldsymbol{y_i} \approx \sum_{\boldsymbol{k \in CZ}} \left[\boldsymbol{a_{ik} W_k^2} + \boldsymbol{b_{ik} W_k}\right] + \boldsymbol{c_{ik}}$$

where W_k is the hourly temperature in climate zone k in the PATHWAYS simulation weather year. Each set of weekday and weekend/holiday shapes are then combined into a single yearlong hourly shape to match the weekend/holiday schedule of the PATHWAYS simulation year. This results in 61 load shapes that reflect the same weather conditions and weekend/holiday schedules as the PATHWAYS simulation year.

The next step is to combine the load shapes to best reflect both the total historical hourly load and the annual electricity demand by subsector. The model achieves this by normalizing each load shape so that it sums to 1 over the year and selecting scaling factors that represent the annual electricity demand associated with each shape. These scaling factors are selected to ensure that the total electricity demand associated with the load shapes in each subsector sums to the electricity demand in that subsector in a selected historical year. An optimization routine is also used to minimize the deviation between the sum of the energy-weighted hourly load shapes and the hourly demand in the same historical year.

The optimization routine includes two additional sets of variables to allow for more accurate calibration to the historical year. The first set of variables addresses limitations in the availability of aggregate load shapes by subsector. Because some of the load shapes being used represent a single household or a single building, aggregation of these shapes may result in more variable load shapes than are seem at the system level. To account for this, the model shifts each load shape by one hour in each direction and includes these shifted load shapes in the optimization in addition to the original load shape. The model then selects scaling factors for each of the three versions of each shape to automatically smooth the shapes if this improves the fit to hourly historical data.

In addition to the load shape smoothing variables, a set of constants are also included in the model for each subsector. This allows the model to translate load shapes up and down (in addition to the scaling) to best approximate the hourly historical load. The constraints that ensure that the load shapes within each subsector sum to the annual electricity demand by subsector are adjusted to ensure that that the energy contribution of the constant term is reflected. The scaling factors and constants solved for in the optimization routine are then used to construct a single shape for each subsector. These shapes are input into PATHWAYS and are scaled in each year according to the subsector electricity demand to form the system-wide hourly load shape. Example load shapes derived using this process are shown in Figure 5. At left, the average daily load shape for weekdays in September corresponding to historical 2010 demand is shown. The load shape at right reflects the impacts of reducing all lighting demands by 50% from the 2010 historical demand.

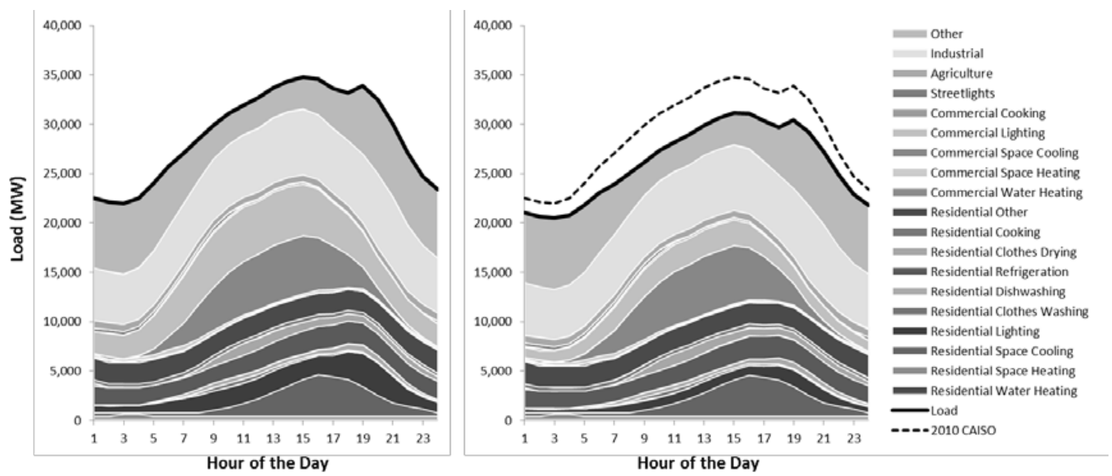


Figure 5. Example load shaping: impact of 50% reduction in lighting demand in average California load shape for weekdays in September, 2010.

Some subsectors in PATHWAYS do not have available representative load shapes. The load shaping module combines these subsectors into an "undefined" subsector and models their contribution to the demand in the optimization routine as a linear combination of all of the available load shapes and a constant. After the optimization routine has solved, the difference between the historical hourly demand and the aggregated hourly shape of all defined subsectors is normalized to sum to 1 and this shape is used to represent any subsectors in PATHWAYS with no specific load shape information.

2.1.2 GENERATION PLANNING

Generation planning occurs in three stages: user-specified resources, renewable policy compliance, and reliability requirement compliance. These are described below.

1. First, the user specifies the capacity (in MW) of or annual energy (in GWh) from each generating resource in each year. Vintages must also be supplied for this fleet of *specified resources* so that they can be retired at the end of their useful life. Early retirement can be imposed by reducing the total installed capacity of a resource type in future years. The model will retire resources of this type according to age (oldest retired first) to meet the yearly capacities specified by the user. In addition, the model will replace generators at the end of their useful life with new resources (with updated cost and performance parameters) of the same type to maintain the user specified capacity in each year. If the resource capacities are not known after a specific year then the user can specify the capacity to be "NaN" and the model will retire resources without replacement at the end of their useful lifetime.

2. In the second stage of generation planning, the model simulates renewable resource procurement to meet a user-specified renewable portfolio standard (RPS). In each year, the renewable net short is calculated as the difference between the RPS times the total retail sales and the total sum of the renewable generation available from specified resources and resources built in prior years. This renewable net short is then supplied with additional renewable build according to user-

specified resource composition rules in each year (e.g. 50% wind, 50% solar PV).

3. The final stage in generation planning is to ensure adequate reliable generating capacity to meet demand. In each year, the model performs a load-resource analysis to compare the reliable capacity to the peak electricity demand. The reliable capacity of the renewable resources is approximated by the total renewable generation level in the hour with the highest net load in the year, where the net load equals the total load minus the renewable generation. The reliable capacity of dispatchable resources is simply equal to the installed capacity. When the total reliability capacity does not exceed the peak demand times a user-specified planning reserve margin, the model builds additional dispatchable resources with a user-specified composition in each year. The default planning reserve margin is equal to 15% of peak demand.

The specified resource capacities by year and their corresponding vintage data were obtained from the Transmission Expansion Planning Policy Commission (TEPPC) 2022 Common Case. Additional input assumptions for renewable resources are listed in Table 3 and

Table 4.

Table 3. Aggregate renewable resource inputs by scenario (% renewable)

Scenario	Year 1	RPS 1	Year 2	RPS 2	Year 3	RPS 3	Year 4	RPS 4
Reference	2013	0	2020	33%				
Electrification	2010	15%	2020	33%	2030	50%	2050	90%
Mixed	2010	20%	2020	33%	2030	50%	2050	90%

Table 4. Renewable resource inputs by scenario and resource type (% of technology type that meets renewable % goal)

Scenario	Reference		Electrification		Mixed	
Year	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
Geothermal		0%	5%	0%	5%	0%
Biomass		0%	0%	0%	0%	0%
Biogas		0%	0%	0%	0%	0%
Small Hydro		0%	0%	0%	0%	0%
Wind		20%	30%	30%	30%	30%
Centralized PV		80%	55%	60%	55%	60%
Distributed PV		0%	0%	0%	0%	0%
CSP		0%	0%	0%	0%	0%
CSP with Storage		0%	10%	10%	10%	10%

The final resource stack determined for each year by the electricity planning module feeds into both the system operations and the revenue requirement calculations. These calculations are described in the following sections.

2.1.3 SYSTEM OPERATIONS

System operations are modeled in PATHWAYS using a loading order of resources with similar types of operational constraints and a set of heuristic designed to approximate these constraints. The system operations loading order is summarized in Figure 6.

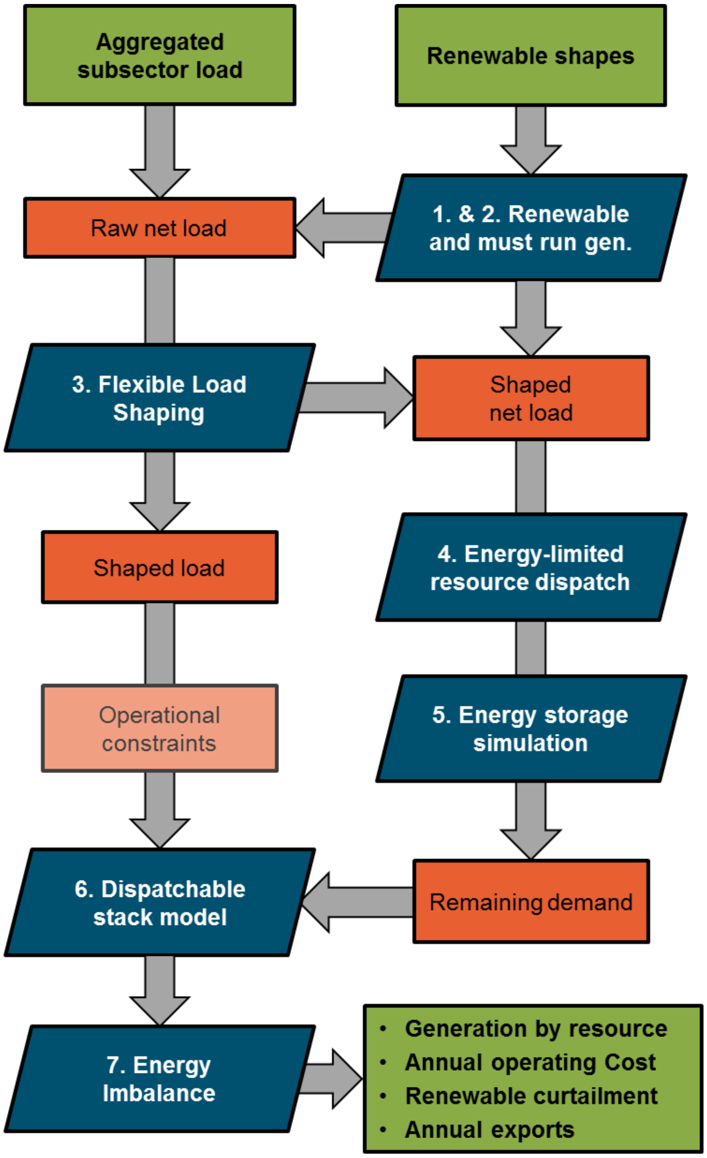


Figure 6. Summary of electricity system operations logic

Consistent with this modeling framework, generation resources must each be classified into one of the following operational modes: must-run; variable renewable; energy-limited; and dispatchable. These classifications are listed for the resource types in this analysis in Table 5.

Table 5. Operational modes by resource type

Technology	Operational Mode
Nuclear	Must-run
CHP	Must-run
Coal	Dispatchable
Combined Cycle Gas (CCGT)	Dispatchable
Steam Turbine	Dispatchable
Combustion Turbine	Dispatchable
Conventional Hydro	Energy-Limited
Geothermal	Must-run
Biomass	Must-run
Biogas	Must-run
Small Hydro	Must-run
Wind	Variable Renewable
Centralized PV	Variable Renewable
Distributed PV	Variable Renewable
CSP	Variable Renewable
CSP with Storage	Variable Renewable

2.1.3.1 Must run resources

Must run resources are modeled with constant output equal to their installed capacity in each year or with constant output that sums to the input annual energy, depending on user specifications. These resources run regardless of the conditions on the system and are therefore scheduled first.

2.1.3.2 Variable renewable resources

Variable renewable resources include any resource that has energy availability that changes over time and has no upward dispatchability. This includes all wind and solar resources. For each of these resources, a resource shape is selected, which characterizes the maximum available power output in each hour. These shapes are scaled in each year to match the total annual energy generation determined by the renewable procurement calculation. These resources can either be constrained to never generate in excess of these scaled renewable shapes (curtailable) or constrained to generate at levels that always exactly match the scaled renewable shapes (non-curtailable). The curtailment is affected by both the load and the ability of other resources on the system to balance the renewable resources. Renewable curtailment is therefore approximated as a *system imbalance* after all other resources have been modeled. The curtailability assumptions for variable renewable resources are summarized in Table 6.

Table 6. Operating assumptions for renewable resources

Technology	Able to Curtail?
Geothermal	No
Biomass	No
Biogas	No
Small Hydro	No
Wind	Yes
Centralized PV	Yes
Distributed PV	No
CSP	Yes
CSP with Storage	No[2]

2.1.3.3 Flexible loads

Flexible loads are modeled at the subsector level. For each demand subsector, the user specifies what fraction of the load is effectively perfectly flexible within the week. Note that this does not imply that the subsector contains loads that can be delayed for up to a week. The model instead approximates each flexible load shape as the weighted sum of a 100% rigid load shape component and a 100% flexible load shape component, which in most extreme case can move in direct opposition to the hourly rigid load shape. It is up to the user to select the weights that best approximate technically feasible load flexibility. Flexible loads in the model are dynamically shaped to flatten the net load (load net of must-run resources and variable renewables) on a weekly basis in each year. The

[2] CSP with Storage resources must generate according to the hourly shape in each hour, but the hourly shape utilizes the energy storage module logic to approximate the dispatchability of these resources.

flexible load dispatch therefore changes both with demand measures and renewable supply measures.

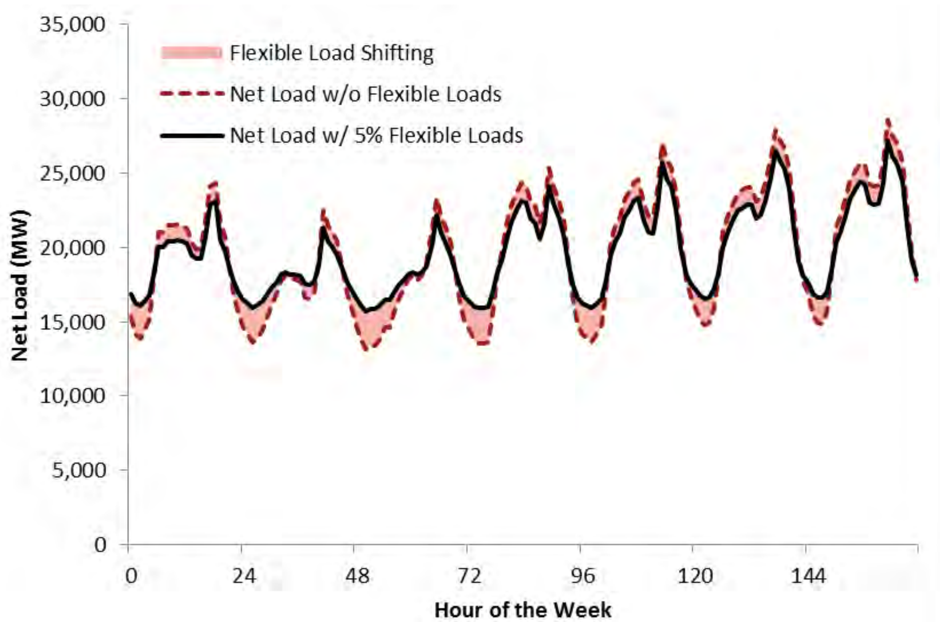


Figure 7. Example of flexible load shifting – 5% of the gross load assumed to be 100% flexible within the week.

The effects of introducing flexible loads on the total net load is shown in Figure 7 for an example week in which 5% of the gross load is approximated as 100% flexible within the week. The input flexible load assumptions are described below.

Table 7. Flexible load assumptions

Scenario			Reference	Electrification	Mixed
Subsector	**Start Year**	**Target Year**	**% Flexible**	**% Flexible**	**% Flexible**
Residential Water Heating	2010	2040	0%	20%	20%
Residential Space Heating	2010	2040	0%	20%	20%
Residential Central AC	2010	2040	0%	20%	20%
Residential Room AC	2010	2040	0%	20%	20%
Residential Clothes Washing	2010	2040	0%	20%	20%
Commercial Water Heating	2010	2040	0%	20%	20%
Commercial Space Cooling	2010	2040	0%	20%	20%
Commercial Space Heating	2010	2040	0%	20%	20%
Light Duty Vehicles	2010	2040	0%	40%	40%

2.1.3.4 Energy-limited resources

Energy-limited resources include any resource that must adhere to a specified energy budget over a weekly time horizon. Some energy-limited resources, like conventional hydropower, have energy budgets that change over time to account for seasonal fluctuations in resource availability and other constraints. Other energy-limited resources, like biomass and biogas, use a dynamic weekly energy budget that distributes resource use between weeks according to the relative electricity imbalance (between load and must-run plus renewable resources) across the weeks. For renewable energy-limited resources, the energy budget ensures that energy from the resources is being delivered for RPS compliance and the energy-limited dispatch also allows the resource to contribute to balancing the system. In addition to the weekly energy budgets, these resources are constrained by weekly minimum and maximum power output levels as well. The dispatch for these resources is approximated using the following heuristic. The method is illustrated in Figure 8 and Figure 9.

1. A normalized hourly demand shape is calculated from the load net of all must-run and variable renewable resources. This net load shape is first translated on a weekly basis so that it averages to zero.

2. The zero-averaged demand shape is then scaled so that the minimum to maximum demand over the course of each week is equal to the minimum to maximum power output of the energy-limited resource.

3. The scaled demand shape is then translated so that the total weekly demand sums to the energy budget of the energy-limited resource.

4. The transformed demand shape calculated in Step 3 will necessarily violate either the minimum or maximum power level constraints for the energy-limited resource in some hours, so two additional steps are required to meet the remaining constraint. In the first of these steps, the transformed demand shape is forced to equal the binding power constraint in hours when it would otherwise violate the constraint. This *truncation* adjustment impacts the summed weekly energy of the transformed demand shape, so a final step is required to re-impose the energy budget constraint.

5. In the weeks in which the transformed demand shape exceeds the energy budget, the model defines a downward capability signal equal to

the difference between the transformed demand shape and the minimum power level. A portion of this signal is then subtracted from the transformed demand shape so that the weekly energy is equal to the energy budget. In the weeks in which the transformed demand shape does not meet the energy budget, the model defines an upward capability signal equal to the difference between the maximum power level and the transformed demand shape. A portion of this signal is then added to the transformed demand shape so that the weekly energy is equal to the energy budget.

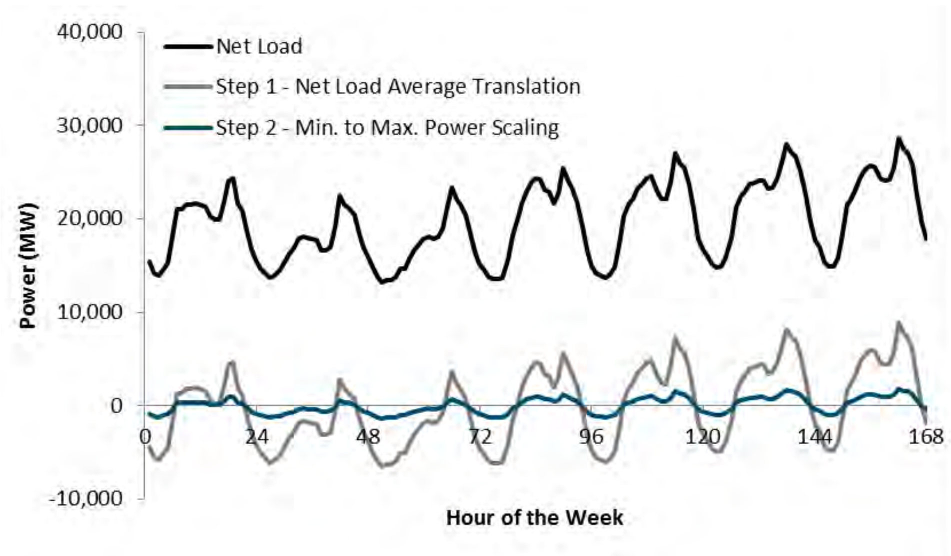


Figure 8. Energy-limited resource dispatch Steps 1 & 2 - normalization and scaling of the net load shape

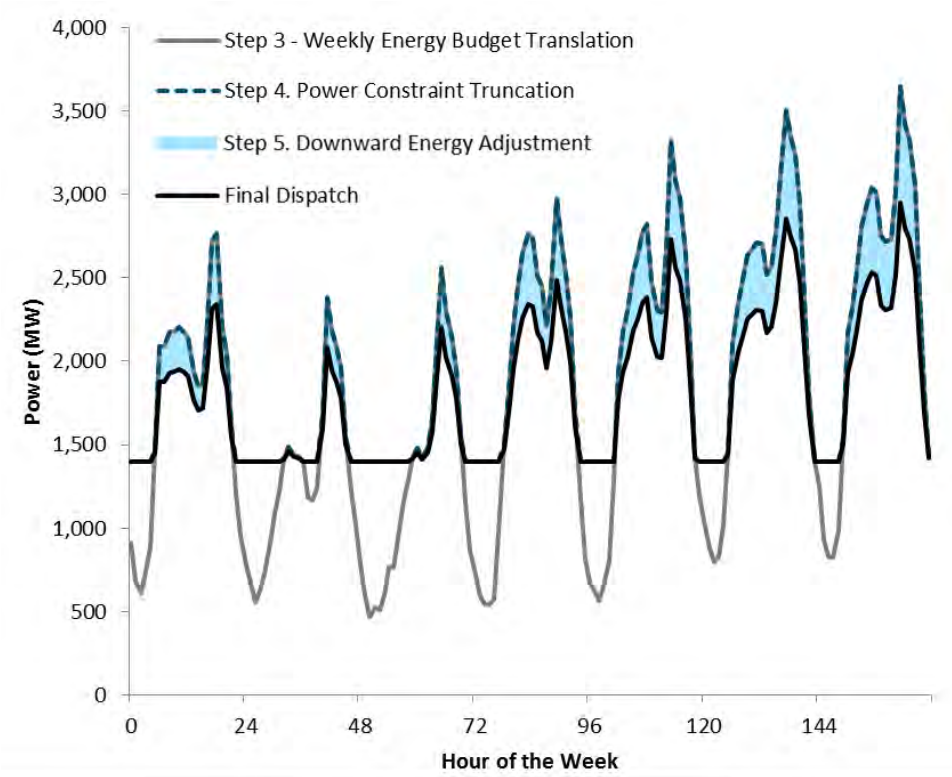


Figure 9. Energy-limited resource dispatch Steps 3 - 5 – translation, truncation, and energy budget adjustment

2.1.3.5 Energy storage

Energy storage resources in PATHWAYS are aggregated into a single equivalent system-wide energy storage device with a maximum charging capacity, maximum discharging capacity, maximum stored energy capacity, and roundtrip efficiency. The simplified energy storage device is described schematically in Figure 10.

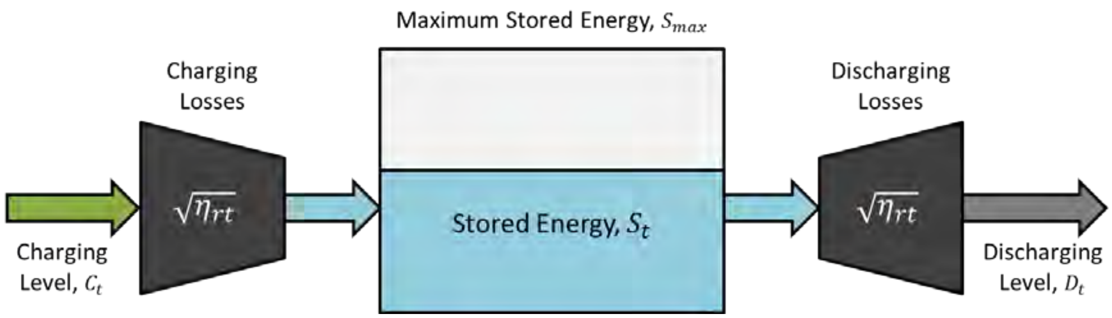


Figure 10. Energy storage model

The storage system acts by storing any renewable energy in excess of the load in each hour (subject to constraints on maximum charging and maximum stored energy) and discharging any stored energy in hours in which the load exceeds the generation from must-run, variable renewable, and energy-limited resources. In PATHWAYS, this functionality is modeled using the following equations in each time step:

$$\mathbf{C_t} = \begin{cases} \mathbf{min}\left(\left\{\mathbf{G_t - L_t, C_{max}, \frac{S_{max} - S_{t-1}}{\sqrt{\eta_{rt}}}}\right\}\right) & \mathbf{if\ G_t > L_t} \\ \mathbf{0} & \mathbf{if\ G_t \leq L_t} \end{cases}$$

$$\mathbf{D_t} = \begin{cases} \mathbf{0} & \mathbf{if\ G_t > L_t} \\ \mathbf{min}\left(\left\{\mathbf{L_t - G_t, D_{max}, \frac{S_{t-1}}{\sqrt{\eta_{rt}}}}\right\}\right) & \mathbf{if\ G_t \leq L_t} \end{cases}$$

$$\mathbf{S_t = S_{t-1} + \sqrt{\eta_{rt}}C_t - \frac{D_t}{\sqrt{\eta_{rt}}}}$$

where G_t is the total generation from must-run, variable renewable, and energy-limited resources, L_t is the load, C_{max} is the maximum charging level, and D_{max} is the maximum discharging level. The hourly year-long dispatch simulation is run in an iterative mode to ensure that the stored energy level at the end of the year matched the stored energy level at the beginning of the year ($S_T = S_0$). This ensures that the storage system provides no net energy to the system. This heuristic storage dispatch algorithm is intended to alleviate short- and long-term energy imbalances, but it is not intended to represent optimal storage dispatch in an electricity market. The operating parameters for the equivalent system-wide energy storage device in each year are calculated from the operating parameters of each storage device that is online in that year. The maximum charging level, maximum discharging level, and maximum stored energy are each calculated as the sum of the respective resource-specific parameters across the full set of resources. The round-trip efficiency is calculated using the following approximation. Consider a storage system that spends half of its time discharging and discharges at its maximum discharge level. For this system, the total discharged energy over a period of length T will equal:

$$\int_0^T \boldsymbol{D_i(t)\,dt = h_i \times D_i^{max} \times \frac{T}{2h_i} = \frac{D_i^{max} \times T}{2}}$$

where h_i is the duration of discharge at maximum discharging capability, D_i^{max}. For this system, the total losses can be described by:

$$\boldsymbol{Losses_i = \int_0^T \frac{1-\eta_i}{\eta_i} D_i(t)\,dt = \frac{(1-\eta_i)D_i^{max} \times T}{2\eta_i}}$$

If the system has several storage devices operating in this way, the total losses are equal to:

$$\boldsymbol{Losses} = \frac{\boldsymbol{T}}{\boldsymbol{2}}\sum_{\boldsymbol{i}}\frac{\boldsymbol{1}-\boldsymbol{\eta_i}}{\boldsymbol{\eta_i}}\boldsymbol{D_i^{max}} = \frac{\boldsymbol{T}}{\boldsymbol{2}}\left(\sum_{\boldsymbol{i}}\frac{\boldsymbol{D_i^{max}}}{\boldsymbol{\eta_i}} - \boldsymbol{D_{max}}\right)$$

where D_{max} is the aggregated maximum discharge capacity. The total discharged energy is equal to:

$$\boldsymbol{Energy} = \sum_{\boldsymbol{i}}\frac{\boldsymbol{D_i^{max}} \times \boldsymbol{T}}{\boldsymbol{2}} = \frac{\boldsymbol{T}}{\boldsymbol{2}}\boldsymbol{D_{max}}$$

The system-wide roundtrip efficiency is therefore approximated by:

$$\frac{\boldsymbol{Energy}}{\boldsymbol{Energy}+\boldsymbol{Losses}} = \frac{\boldsymbol{D_{max}}}{\boldsymbol{D_{max}} + \sum_i \frac{\boldsymbol{D_i^{max}}}{\boldsymbol{\eta_i}} - \boldsymbol{D_{max}}} = \frac{\boldsymbol{D_{max}}}{\sum_i \frac{\boldsymbol{D_i^{max}}}{\boldsymbol{\eta_i}}}$$

The energy storage operational parameters used in this analysis are summarized in Table 8 and the energy storage build assumptions are listed in

Table 9.

Table 8. Energy storage technology operational parameters

Technology	Year 1	Roundtrip Efficiency in Year 1	Year 2	Roundtrip Efficiency in Year 2
Pumped Hydro	2010	70.5%	2020	80%
Batteries	2010	75%	2020	80%
Flow Batteries	2010	75%	2020	80%

Table 9. Energy storage scenario assumptions

Scenario	Technology	MW	Hours at Max. Discharge	Start Year	Target Year
Reference	Pumped Hydro	2,427	93	2010	2011
Electrification	Pumped Hydro	2,427	93	2010	2011
Electrification	Pumped Hydro	5,000	12	2020	2040
Electrification	Flow Batteries	15,000	6	2020	2050
Mixed	Pumped Hydro	2,427	93	2010	2011
Mixed	Pumped Hydro	5,000	12	2020	2040

2.1.3.6 Dispatchable resources

Dispatchable resources are used to provide the remaining electricity demand after must-run, variable renewable, energy-limited, and storage resources have been used. Dispatch of these resources, which include thermal resources and imports, is approximated using a stack model with heuristics to approximate operational constraints that maintain system reliability. In the stack model, resources are ordered by total operational cost on a $/MWh basis. The operational cost includes: fuel costs equal to the fuel price times the heat rate; carbon costs equal to the price of carbon times the fuel carbon intensity times the heat rate; and input variable operations and maintenance costs. Resources are dispatched in stack order until the remaining load is met. The default operational constraint is to require 10% of the gross electricity load to be met with dispatchable thermal resources in all hours. Imports have user-specified heat rates and capacities to best approximate historical path flows and import constraints. Dispatchable resource operational parameters are listed in Table 10 and

Table 11.

Table 10. Dispatchable technology heat rate assumptions[3]

Technology	Year 1	Heat Rate in Year 1 (MMBtu/kWh)	Year 2	Heat Rate in Year 2 (MMBtu/kWh)
Coal	2012	10,130	2027	9,000
Combined Cycle Gas (CCGT)	2012	7,000	2027	6,900
Steam Turbine	1980	14,000	2027	14,000
Combustion Turbine	2012	10,500	2027	9,200

Table 11. Dispatchable technology variable O&M assumptions[4]

Technology	Variable O&M Cost (2008$/MWh)
Coal	4.32
Combined Cycle Gas (CCGT)	4.92
Steam Turbine	5
Combustion Turbine	5

2.1.3.7 System imbalances

Once the dispatch has been calculated for each type of resource, the model calculates any remaining energy imbalances. The planning module is designed to ensure that no unserved energy is experienced in the operational simulation, but the system might encounter potential overgeneration conditions, in which the generation exceeds demand. These conditions might arise due to a combination of factors, including low load, high must run generation, high variable renewable generation, and minimum generation operating constraints.

[3] Heat rate assumptions were informed by E3, "Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process," Prepared for the Western Electric Coordinating Council, Oct. 9, 2012.
<http://www.wecc.biz/committees/BOD/TEPPC/External/E3_WECC_GenerationCostReport_Final.pdf>
[4] Derived from operating parameters in TEPPC 2022 Common Case

Overgeneration conditions are first mitigated with exports to neighboring regions, based on the user-specified maximum export level. For accounting purposes, the exported power emissions rate is approximated as the generation-weighted average emissions rate of all resources generating in each hour. If excess generation remains after accounting for exports, then overgeneration is avoided by curtailing renewable resources. Curtailment is not attributed to specific renewable resources, but does impact the total annual delivered renewable energy. Both the delivered renewable energy and the percent of renewable generation that is curtailed in each year are outputs of the model. The model does not procure additional renewable resources to meet RPS targets if renewable curtailment results in less delivered RPS energy than is required for compliance. This renewable overbuild must be decided by the user.

The system operations module outputs include:

- Total annual generation from each technology and fuel type
- Total annual electric sector emissions
- Total electric sector fuel, variable O&M, and carbon costs
- Expected annual delivered renewable energy and percent of renewable generation curtailed

2.1.4 REVENUE REQUIREMENT

The revenue requirement calculation includes the annual fixed costs associated with generation, transmission, and distribution infrastructure as well as the annual variable costs that are calculated in the System Operations Module. The methodology for calculating fixed costs in each year is described below.

2.1.4.1 Generation

Fixed costs for each generator are calculated in each year depending on the vintage of the generator and the user-specified capital cost and fixed O&M cost inputs by vintage for the generator technology. Throughout the financial lifetime of each generator, the annual fixed costs are equal to the vintaged capital cost times a levelization factor plus the vintage fixed O&M costs, plus taxes and insurance. For eligible resources, taxes are net of production tax credits and/or investment tax credits. If the plant's useful lifetime is longer than its financing lifetime, then no fixed costs are calculated for the years between the end of the financing lifetime and the retirement of the plant. This methodology is also used to cost energy storage infrastructure and combined heat and power infrastructure. Input cost assumptions for generation are summarized below.[5]

[5] Cost assumptions were informed by E3, "Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process," Prepared for the Western Electric Coordinating Council, Oct. 9, 2012.
<http://www.wecc.biz/committees/BOD/TEPPC/External/E3_WECC_GenerationCostReport_Final.pdf>

Table 12. Capital cost assumptions

Technology	Capital Cost from present - 2026 (2012$/kW)	Assumed change in real capital cost by 2050 % change	Capital Cost from 2027 - 2050 (2012$/kW)
Nuclear	9,406	0%	9,406
CHP	1,809	0%	1,809
Coal	4,209	0%	4,209
Combined Cycle Gas (CCGT)	1,243	16%	1,441
CCGT with CCS	3,860	-3%	3,750
Steam Turbine	1,245	0%	1,245
Combustion Turbine	996	44%	1,431
Conventional Hydro	3,709	0%	3,709
Geothermal	6,726	0%	6,726
Biomass	5,219	0%	5,219
Biogas	3,189	0%	3,189
Small Hydro	4,448	0%	4,448
Wind	2,236	-9%	2,045
Centralized PV	3,210	-31%	2,230
Distributed PV	5,912	-30%	4,110
CSP	5,811	-25%	4,358
CSP with Storage	7,100	-30%	5,000

Table 13. Fixed O&M cost assumptions

Technology	Year 1	Fixed O&M in Year 1 (2012$/kW-yr)	Year 2	Fixed O&M in Year 2 (2012$/kW-yr)
Nuclear	2012	72.62	2027	72.62
CHP	2012	0	2027	0
Coal	2012	35.6	2027	35.6
Combined Cycle Gas (CCGT)	2012	11.9	2027	11.9
CCGT with CCS	2012	18.4	2027	18.4
Steam Turbine	2012	11.9	2027	11.9
Combustion Turbine	2012	7.1	2027	14.2
Conventional Hydro	2012	35.6	2027	35.6
Geothermal	2012	155.6	2027	155.6
Biomass	2012	184	2027	184
Biogas	2012	154	2027	154
Small Hydro	2012	35.6	2027	35.6
Wind	2012	71.2	2027	71.2
Centralized PV	2012	59.3	2027	59.3
Distributed PV	2012	65.2	2027	65.2
CSP	2012	71.2	2027	71.2
CSP with Storage	2012	60.0	2027	60.0

Financing assumptions and other technology-specific inputs are listed below.

Table 14. Financing assumptions[6]

Technology	Financing Lifetime (yrs)	% ITC Eligible	MACRS Term (yrs)	Insurance Rate	Property Tax Rate	Useful Life (yrs)
Nuclear	20	0%	20	0.5%	1%	50
CHP	20	0%	20	0%	0%	20
Coal	20	0%	20	0.5%	1%	40
Combined Cycle Gas (CCGT)	20	0%	20	0.5%	1%	40
CCGT with CCS	20	0%	20	0.5%	1%	40
Steam Turbine	20	0%	20	0.5%	1%	60
Combustion Turbine	20	0%	20	0.5%	1%	40
Conventional Hydro	20	0%	20	0.5%	0%	80
Geothermal	20	0%	5	0%	0%	20
Biomass	20	0%	20	0%	0%	20
Biogas	20	0%	20	0%	0%	20
Small Hydro	20	0%	20	0.5%	1%	20
Wind	20	0%	5	0%	0%	20
Centralized PV	20	95%	5	0%	1%	20
Distributed PV	20	95%	5	0%	0%	20
CSP	20	95%	5	0%	0%	20
CSP with Storage	20	95%	5	0%	0%	20

Cost and financing assumptions for energy storage technologies are summarized below.

[6] Consistent with financing assumptions used in Williams et al, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science*: 335 (6064), 53-59.

Table 15. Capital cost inputs for energy storage technologies

Technology	Capital Cost (2012$/MW)	Financing Lifetime (yrs)	Useful Life (yrs)
Pumped Hydro	2.23M	30	30
Batteries	4.3M	15	15
Flow Batteries	4.3M	15	15

2.1.4.2 Transmission

Transmission costs are broken into three components: RPS-driven transmission costs, sustaining transmission costs, and reliability upgrade costs. RPS-driven costs are approximated as a fixed input $/MWh times the total renewable generation in each year. Sustaining transmission costs are calculated in a reference year as the difference between the total transmission costs in that year and the RPS-driven costs calculated for that year. A user-specified portion of these costs are then escalated with the peak demand and the remaining portion is escalated according to a user-specified real cost escalation rate. Reliability upgrade costs are specified by the user in a reference year and are escalated using the same method that is used for the sustaining transmission costs. Input assumptions for transmission costs are listed below.

Distribution Table 16. Transmission cost assumptions

Cost Component	Reference Year	Total Cost Reference Year	Real Escalation Rate	Portion that Escalates with Peak Demand	Renewable Cost Multiplier
Reliability Upgrades	2012	$120M	1%	50%	
Sustaining Transmission			2%	50%	
RPS-Driven Transmission					$34/MWh
Total Transmission Cost	*2012*	*$2.6B*			

2.1.4.3

Distribution costs are broken into distributed renewable-driven costs and non-renewable costs. Renewable-driven costs are approximated as a fixed input $/MWh times the total renewable generation in each year. This calculation assumes that distributed renewable energy grows at the same rate as centralized renewable energy. The user must also use care to ensure that the $/MWh input reflects only distribution costs relative to the entire renewable portfolio, rather than just distributed resources. Non-renewable distribution costs are input by the user for a reference year and escalated with the peak demand.

Table 17. Distribution cost assumptions

Cost Component	Reference Year	Total Cost Reference Year	Real Escalation Rate	Portion that Escalates with Peak Demand	Renewable Cost Multiplier
Non-renewable			2.5%	50%	
Renewable-driven					$0/MWh
Total Distribution Cost	*2012*	*$10B*			

2.1.4.4 Calibration to reference year

The revenue requirement also includes other costs, like program costs and customer incentives. These costs are approximated with an adder that is calibrated to a historical reference year. For this calibration, the user specifies the average electricity rate in a historical year. The total revenue requirement in the historical reference year is then calculated by multiplying the average rate by the total sales calculated for the year in PATHWAYS. The cost adder in the reference year is equal to the difference between the calculated reference revenue requirement and the sum of the generation, transmission, and distribution costs. The cost adder is then scaled with the total sales in each year and added to the generation, transmission, and distribution costs calculated by the model in each year to arrive at the total revenue requirement. Average electricity rates are approximated by dividing the total revenue requirement by the total sales in each year, which reduces to:

$$\boldsymbol{Average\ Rate} = \frac{\boldsymbol{C_{gen}^{fixed} + C_{gen}^{var} + C_{gen}^{fuel} + C_{trans} + C_{dist}}}{\boldsymbol{Total\ Sales}} + \boldsymbol{Rate\ Adder}$$

where C_{gen}^{fixed} includes all generator fixed costs, C_{gen}^{var} and C_{gen}^{fuel} are determined by the system operations calculation, C_{trans} includes all transmission costs, and C_{dist} includes all distribution system costs for a given year. The *rate adder* reflects the constant revenue requirement adder in the reference year, normalized by the total sales in the reference year.

These average electricity rates are applied to the annual electricity demand by subsector to allocate electricity costs between subsectors. For a given subsector, the electricity costs in a given year are therefore:

$$\boldsymbol{Electricity\ Costs = Average\ Rate\ \times Electricity\ Demand}$$

2.1.5 EMISSIONS

The electricity module also calculates an average emissions rate for electricity generation based on the emissions rates specified for each generating technology and the energy generated by each technology in each year. The average emissions rate, E, for electricity is therefore:

$$\boldsymbol{E = \frac{\sum_{k,t} P_{k,t} \times e_k}{Total\ Sales}}$$

where $P_{k,t}$ is the power output in hour t (within the year of interest) from generating technology k, and e_k is the emissions rate of generating technology, which is equal to the carbon intensity of the fuel times the heat rate. The emissions associated with electricity demand for each subsector is therefore approximated by:

$$\boldsymbol{Emissions = E\ \times Electricity\ Demand}$$

2.2 Pipeline gas

We use the term pipeline gas here to acknowledge the potential of the pipeline to deliver products other than traditional natural gas. We model multiple decarbonization strategies for the pipeline including biomass conversion processes, hydrogen, and synthetic methane from power-to-gas processes. Below is a description of the commodity products included in the pipeline in our decarbonization scenarios as well as a discussion of our approach to modeling delivery charges for traditional as well as compressed and liquefied pipeline gas.

2.2.1 NATURAL GAS

Natural gas price forecasts are taken from the EIA's Annual Energy Outlook 2013（EIA，2013） for its reference case scenario and are shown below.

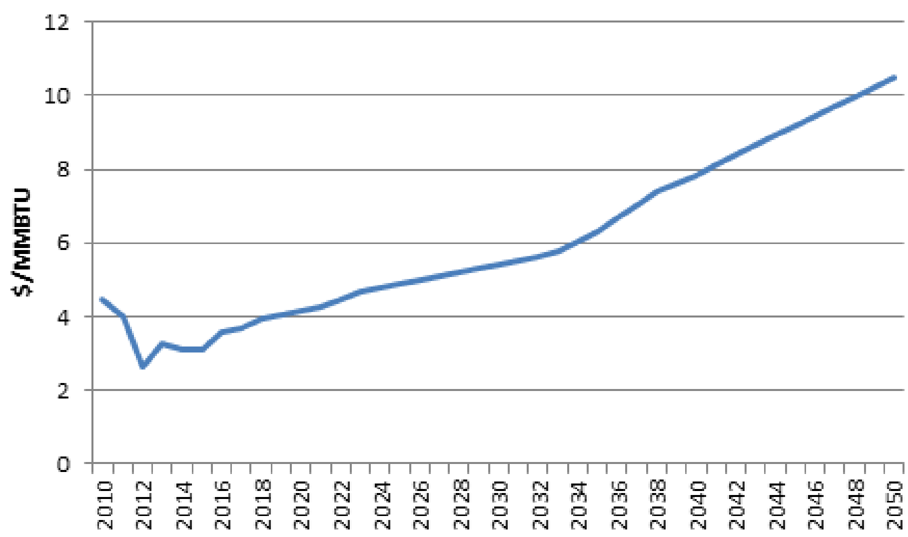


Figure 11. Natural gas commodity forecast

2.2.2 BIOMASS

A full description of the biomass methodology employed in PATHWAYS for all energy delivery types (liquid fuels, electricity, and pipeline gas) is available in section 3.

2.2.3 HYDROGEN

Hydrogen production in the model comes from both low carbon electricity generation – nuclear and renewable energy – and from natural gas with pre-combustion CCS. The data for estimating hydrogen production and delivery costs is adapted from the DOE Hydrogen Analysis Project (H2A). The production portion of the hydrogen module draws current and future assumptions from version 2.1 of the H2A production modeling, utilizing both centralized grid electrolysis and centralized natural gas reformation with CCS technology case studies. Hydrogen delivery draws current and future assumptions from version 2.3 of the H2A delivery model. The values used in the model are shown in Table 18 below.

Table 18. Hydrogen production parameter values from DOE Hydrogen Analysis Project.

Parameter	Grid Electrolysis	Natural Gas with CO_2 Sequestration
Plant Life	40	40
Initial Year	2005	2005
Initial Levelized Fixed Capacity Costs ($/kG-year)	1.53	0.14+0.45+0.09
Initial Efficiency (LHV)	0.74*0.88	0.71*0.88
Forecast Year	2030	2030
Forecast Levelized Fixed Capacity Costs ($/kG-year)	0.65	0.12+0.35+0.07
Forecast Efficiency (LHV)	0.884*0.88	0.711
Production Feedstock	Electricity	Pipeline Gas
Non-energy Variable Operating Costs ($/kG)	0.05	0.17
Capacity Factor	0.25	0.9
CO_2 Capture Ratio	0	0.9

Conversion efficiencies are the product of the efficiency of the hydrogen production process, either electrolysis of water or reformation of natural gas, times a factor of 0.88, which includes energy losses in gas cleaning and other system inefficiencies. The time trajectory of overall system efficiency for grid and natural gas CCS hydrogen production is shown in **Error! Reference source not found.**.

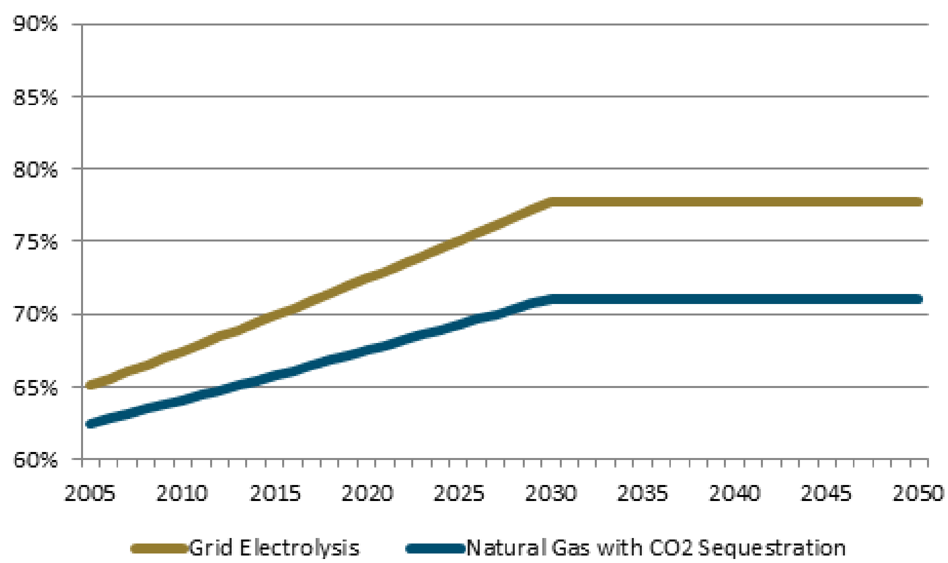


Figure 12. Conversion efficiency of hydrogen production from grid electrolysis and natural gas CCS

Levelized capital costs in the current year were calculated based on the respective H2A models for centralized grid electrolysis and centralized natural gas reformation. Capital cost reductions for 2030 were taken from H2A modeled future cases. The rate of decline to 2030 was assumed to follow the function

$$\mathbf{Cost_{Yr}} = \mathbf{Cost_i} * \mathbf{e}^{\left[\ln\left(\frac{\mathbf{Cost_f}}{\mathbf{Cost_i}}\right) * \frac{(\mathbf{Yr}-\mathbf{Cost_i})}{(\mathbf{Yr_f}-\mathbf{Yr_i})}\right]}$$

The overall levelized capital cost trajectory is shown in Figure 13.

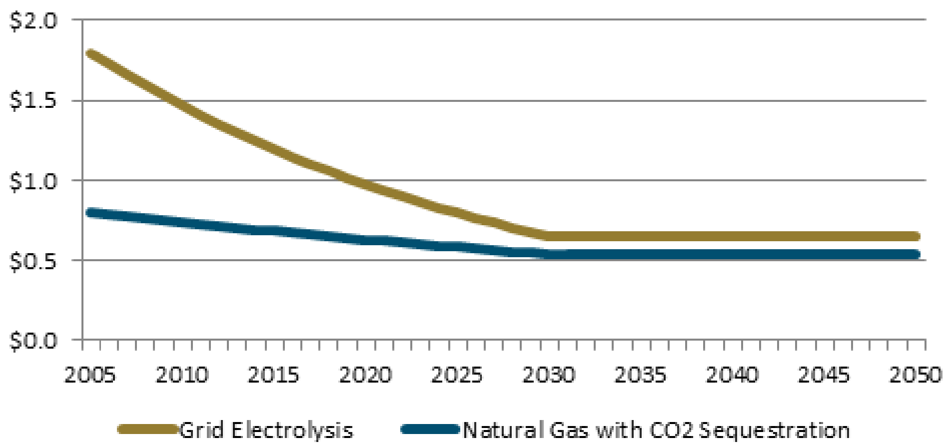


Figure 13. Levelized capital cost of hydrogen from grid hydrolysis and natural gas pre-combustion CCS.

Total annual hydrogen production is a user input. Hydrogen production capacity is built within the model to meet the user defined production level, with a stock roll-over constraint. Capacity factors are taken from the H2A models, with electrolysis running at a low capacity factor to take advantage of periods with low electricity prices. Total costs are the sum of capacity costs and variable costs, including input energy (natural gas or electricity) cost and non-fuel variable cost components. The model assumes that electrolysis-based hydrogen production pays the California average electricity rate.

2.2.4 SYNTHETIC NATURAL GAS (SNG)

SNG is produced in the model from low carbon electricity, which is used to produce hydrogen from electrolysis. In the model, the hydrogen undergoes methanation using CO_2 from air capture. The data used for estimating SNG production costs from this process is adapted from ***Power to Gas – a Technical Review*** authored by Gunnar Benjaminsson, Johan Benjaminsson, and Robert Boogh Rudberg, and published by the Swedish Gas Technology Center (SGC). These are summarized in Table 19. It should be emphasized that while SNG from power to gas is currently being demonstrated on small scale (6 MW is the largest current plant in the world), and includes air capture of CO_2, the cost estimates used here are still highly speculative due to the lack of data from large commercial operation of SNG plants.

Table 19. SNG production parameters in model based on Swedish Gas Technology Center report

Parameter	Value
Plant Life	15
Initial Year	2012
Initial Levelized Fixed Capital Costs ($/mmBtu-year)	18.5
Initial Efficiency	0.52
Forecast Year	2032
Forecast Levelized Fixed Capital Costs ($/mmBtu-year)	7.6
Forecast Efficiency	0.78*0.81
Production Feedstock	Electricity
Non-energy Variable Operating Costs ($/mmBtu)	6.5
Capacity Factor	0.25

Current year process efficiency is 52%, which is the product of an electrolysis efficiency of 65% and methanation efficiency (catalytic or biological) of 81%. Forecast efficiency in 2032 is 63%, based on the same methanation efficiency and an improved electrolysis efficiency of 78%. Process efficiency improves linearly from 2013 to 2032, and remains constant thereafter (**Error! Reference source not found.**).

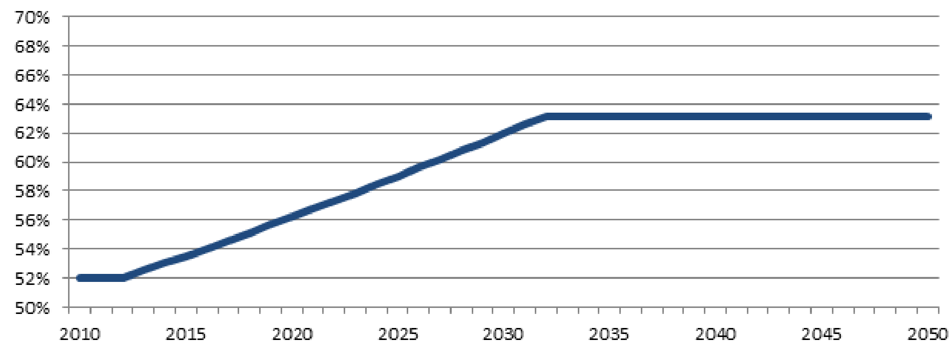


Figure 14. SNG production efficiency over time, based on SGC report

Levelized current capital cost of SNG production capacity is based on the SGC report, assuming production on the order of 25 mmBtu per hour. The capital cost assumption is probably optimistic both in terms of production volume (the throughput rate is higher than any facility currently operating) and because it leaves out plant maintenance costs, which would add approximately 10% to the levelized capital cost. Capital cost reductions to 2032 are assumed to follow the function below:

$$\boldsymbol{Cost_{Yr}} = \boldsymbol{Cost_i} * \boldsymbol{e}^{\left[\boldsymbol{ln}\left(\frac{\boldsymbol{Cost_f}}{\boldsymbol{Cost_i}}\right) * \frac{(\boldsymbol{Yr}-\boldsymbol{Cost_i})}{(\boldsymbol{Yr_f}-\boldsymbol{Yr_i})}\right]}$$

The levelized cost trajectory is shown in Figure 15.

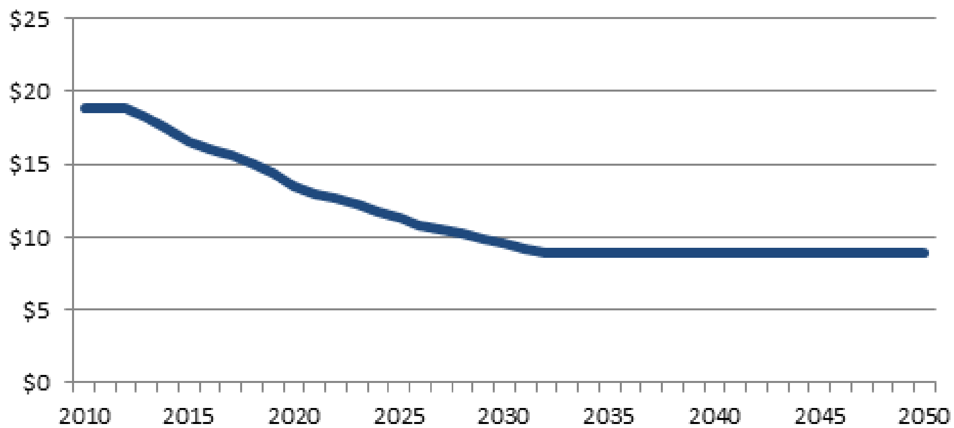


Figure 15. SNG production levelized capital cost

Annual SNG production is a model input. SNG production capacity is built by the model to meet the annual production level, based on a capacity that is assumed to be driven by the electrolysis process and is therefore identical to the assumption of electrolysis capacity factor of 25%. Total costs are a function of capacity costs and variable costs for production, including fuel/electricity costs. SNG capacity follows a stock roll-over that assumes a 15 year plant life. New capacity is added as necessary to meet the target annual production. Production energy costs are simply electricity costs, which are the average electricity rate for California. CO_2 air capture costs are assumed to be included within plant capacity costs.

2.2.5 DELIVERY COSTS

We model the California pipeline system's delivery of pipeline gas as well as compressed pipeline gas, and liquefied pipeline gas for transportation uses. We model these together in order to assess the capital cost implications of changing pipeline throughput volumes. Delivery costs of pipeline gas are a function of capital investments at the transmission and distribution-levels and delivery rates can be broadly separated into core (usually residential and small commercial) and non-core (large commercial, industrial, and electricity generation) categories. Core service traditionally provides reliable bundled services of transportation and sales compared to non-core customers with sufficient volumes to justify transportation-only service. The difference in delivery charges can be significant. In September, 2013 the average U.S. delivered price of gas to an industrial customer was $4.39/thousand cubic feet compared to $15.65/thousand cubic feet for residential customers （United States Energy Information Administration，2013）． This difference is driven primarily by the difference in delivery charges for different customer classes.

To model the potential implications of large changes in gas throughput on delivery costs, we use a simple revenue requirement model for each California IOU. This model includes total revenue requirements by core and non-core customer designations, an estimate of the real escalation of costs (to account for increasing prices of commodities, labor, engineering, etc.) of delivery services, an estimate of the remaining capital asset life of utility assets, and the percent of the delivery rate related to capital investments. These last two model inputs influence the rate at which the rate base depreciates, which will affect the delivery rates under scenarios where there is a rapid decline in pipeline throughput that outpaces capital depreciation. We assume that 50% of the revenue requirement of a gas utility is related to throughput growth and that capital assets have an average 30-year remaining financial life. This means that the revenue requirement at most could decline 1.7% per year and that any decline in throughput exceeding this rate would result in escalating delivery charges for remaining customers. This is a result of utilities being forced to recover revenue from a declining amount of throughput, increasing rates for remaining customers and potentially encouraging fuel switching, thus accelerating the process. These costs will have to be recovered and so need to continue to be represented even in scenarios where there are rapid declines in pipeline throughput.

2.2.5.1 Compressed pipeline gas

We model the costs of compression facilities at $.87/Gallons of Gasoline Equivalent (GGE) based on an average of cost ranges reported by Argonne National Laboratory （Argonne National Laboratory，2010）. Additionally, we model the electricity use of compressing facilities at 1 kWh per GGE based on the same report. These inputs affect the emissions associated with compressed pipeline gas relative to pipeline gas.

2.2.5.2 Liquefied pipeline gas

We model the non-energy costs of liquefaction facilities at $.434/Gallons of Gasoline Equivalent (GGE) based on an analysis by the Gas Technology Institute （Gas Technology Institute，2004）. Additionally, we model the electricity use of liquefaction facilities using electric drive technologies at $3.34 kWh per GGE based on the same report. These inputs affect the emissions associated with liquefied pipeline gas relative to pipeline gas.

2.3 Liquid fuels

Liquid fuels are primarily fuels used for transportation and include diesel, gasoline, jet-fuel, and hydrogen as well as LPG. We model biofuel processes for both diesel fuel as well as gasoline that are described further in section 3. Jet-fuel and LPG are only supplied as conventional fossil fuels. The sections below discuss conventional fossil price projections as well as liquid hydrogen delivery.

2.3.1 FOSSIL FUELS

Conventional fossil fuel price projections are taken from the AEO 2013 reference case scenario. They include both commodity as well as delivery costs for fuels delivered to the Pacific census division.

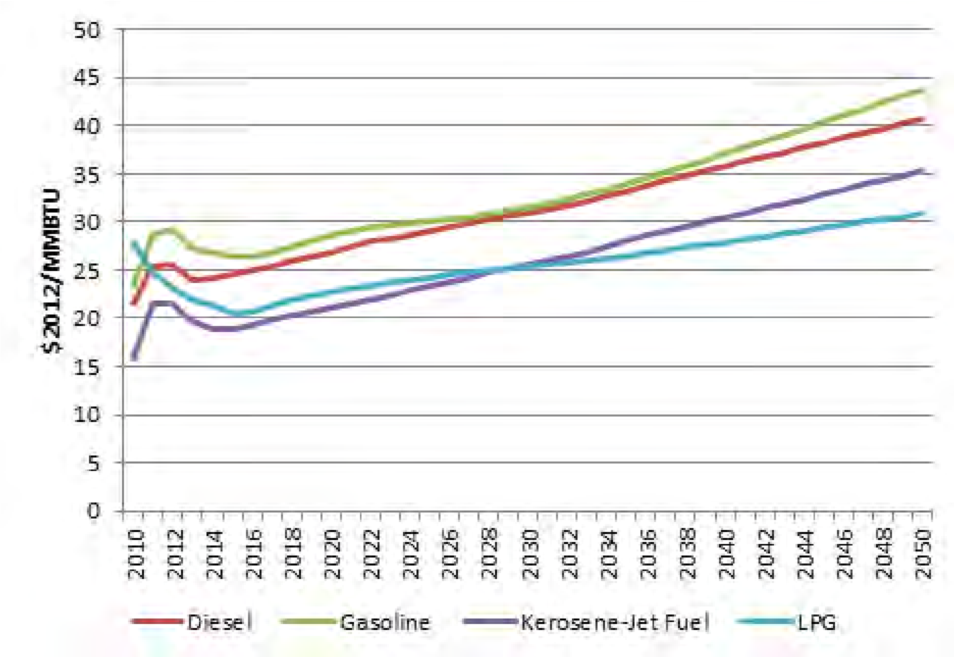


Figure 16. Fossil fuel price projections

2.3.2 LIQUID HYDROGEN

The hydrogen that is simply injected into the pipeline for distribution to end uses incurs no additional delivery costs in the model. The hydrogen that is liquefied for use in transportation, however, does incur delivery costs in addition to production costs. Delivery costs include liquefaction in a large scale plant, delivery by truck, and refueling. Parameter values for hydrogen delivery are based on H2A, as summarized in Table 20.

Table 20. Liquefied hydrogen delivery parameters.

Parameter	Value
Plant Life	30
Initial Year	2007
Initial Levelized Fixed Capacity Costs ($/kG-year)	1.01
Initial Efficiency (kWh/kg)	9.32
Forecast Levelized Fixed Capacity Costs ($/kG-year)	0.44
Forecast Year	2025
Forecast Efficiency (kWh/kg)	6.3
Production Feedstock	Electricity
Non-energy Variable Operating Costs ($/kG)	0
Capacity Factor	0.5

Levelized capital costs for the current year and 2030 were calculated based on the H2A delivery model, with the the rate of capital cost decline to 2030 assumed to follow the function

$$\boldsymbol{Cost_{Yr} = Cost_i * e^{\left[ln\left(\frac{Cost_f}{Cost_i}\right) * \frac{(Yr - Cost_i)}{(Yr_f - Yr_i)}\right]}}$$

The overall levelized capital cost trajectory for liquefied hydrogen delivery is shown in **Error! Reference source not found.**.

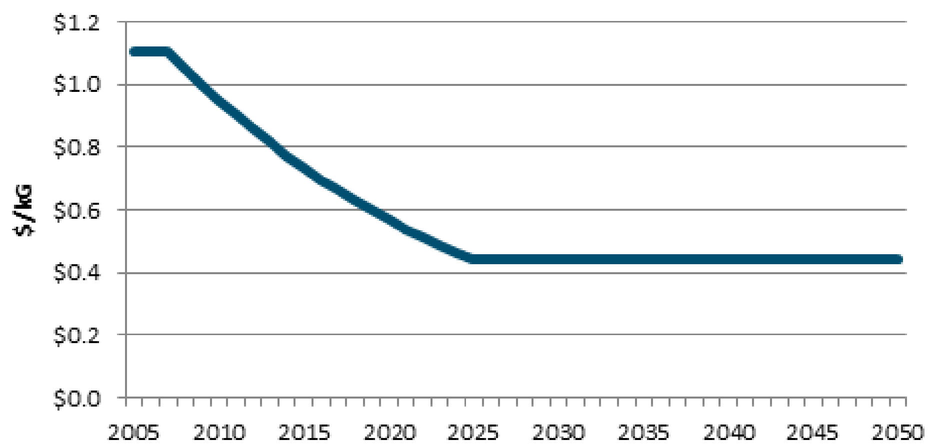


Figure 17. Levelized capital cost of liquefied hydrogen delivery, based on H2A

Forecast efficiency of delivery is taken from the H2A model and is assumed to improve over time. The improvement in process efficiency assumes a functional form identical to the cost reduction.

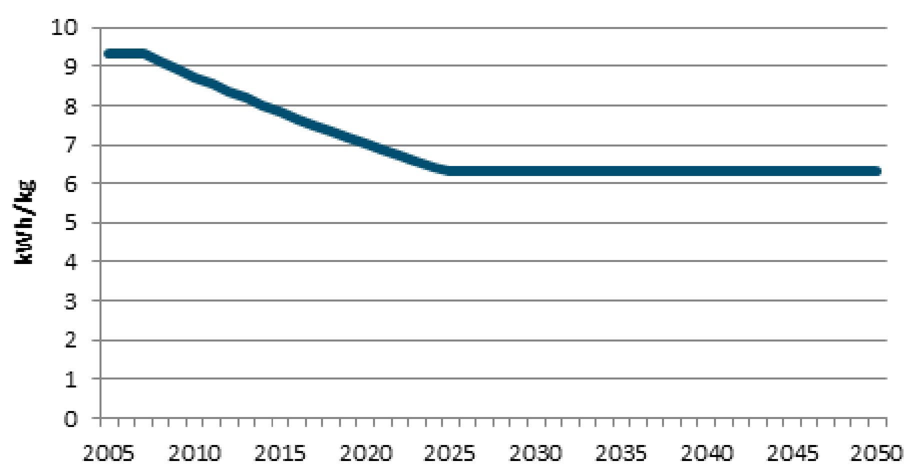


Figure 18. Liquefied hydrogen delivery efficiency, based on H2A.

As in the case of hydrogen production, the annual amount of delivered hydrogen is a user-defined input. Delivery capacity follows a basic stock roll-over model, with new capacity added as necessary to enable delivery. Delivery variable costs include electricity costs, based on the California average electricity rate.

2.3.3 REFINERY AND PROCESS GAS; COKE

We do not model any costs associated with refinery and process gas. We do model the costs of coke from the 2013 AEO Reference Case scenario （EIA, 2013）.

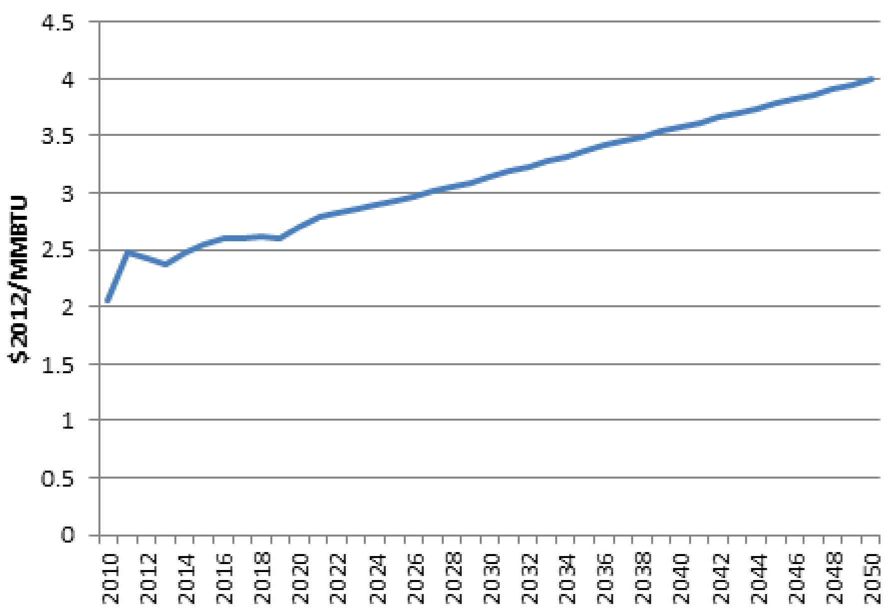


Figure 19. Petroleum coke price projection

3 Biomass

3.1 Resource assessments

The U.S. Department of Energy's 2011 Billion Ton Study Update (BT2) provides the most comprehensive analysis of biomass feedstock potential through 2030 for the United States. It provides a well-documented and publicly vetted foundation for analysis of the cost and magnitude of the US biomass resource base. However, there are a number of valid criticisms of the methods used that must be incorporated into a neutral assessment. Some of the most important critiques of the BT2 and their implications for long-term biomass supplies are described below.

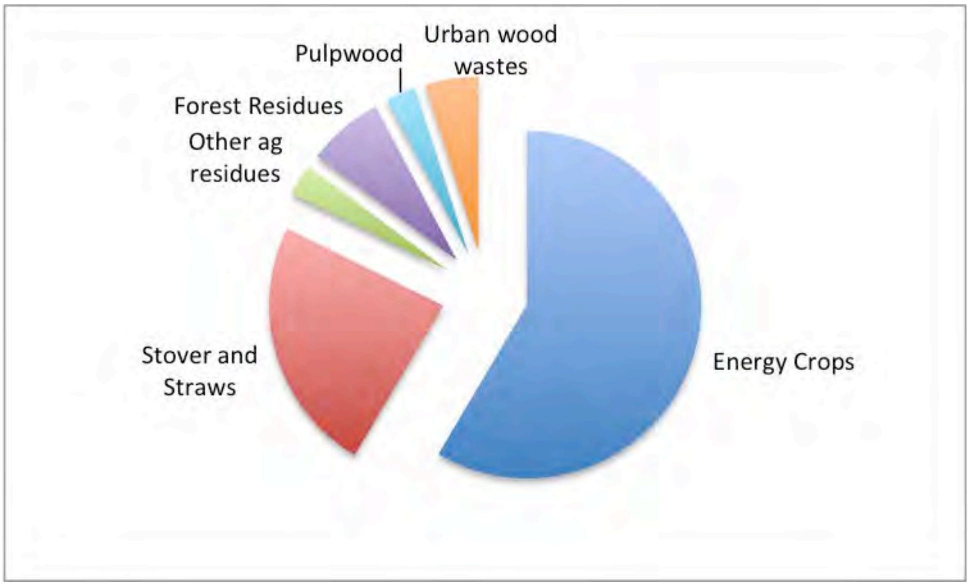


Figure 20. 2030 Billion Ton Study Update feedstock breakdown by weight at $80/ton. (Parker, 2011)

3.1.1 ENERGY CROPS

Energy crops are grown for the purpose of being used in energy production, and are chosen for high yields of biomass. They must compete with either conventional crops or pasture for land. The yield and production cost of an energy crop are therefore the two most important factors that impact its profitability and therefore whether it is competitive with incumbent land uses. The BT2 takes an optimistic view of both yields and costs in its baseline assessment and performs no sensitivity on more pessimistic parameter values.

On yield, modeled values used in BT2 are based on data from relatively small-scale trials on good agricultural lands. These yields are then used to represent the yield of an energy crop on all agricultural lands. Not surprisingly, in the modeling this leads to significant displacement of incumbent crops and pasture on marginally productive lands, but there is little evidence that the energy crop yields applied are representative of achievable yields on those marginal lands. This is a common assumption for large scale energy crop production in agricultural economic models. There is no way to systematically correct for this bias in the data.

The BT2 costs are optimistic relative to available estimates from university extension specialists who are advising farmers considering whether to grow these new crops (Duffy 1999; Wilkes 2007). Parker (2011) developed a production cost model that varied with yield based on the crop budget provided by Duffy. The costs are significantly higher especially at the high yields that are likely to induce adoption. The difference appears to be a large difference in the harvest cost and in how the harvest cost scales with yield. Based on the INL feedstock supply logistics model, the harvesting equipment is throughput limited at 2 tons per acre leading to no reductions in harvest costs as yield go over 2 tons per acre. On average, adding $17/ton of energy crop would bring the BT2 costs in line with the cost reported by extension specialists. This analysis applies to herbaceous energy crops. Further analysis would be needed to understand the quality of the woody energy crop estimate in BT2.

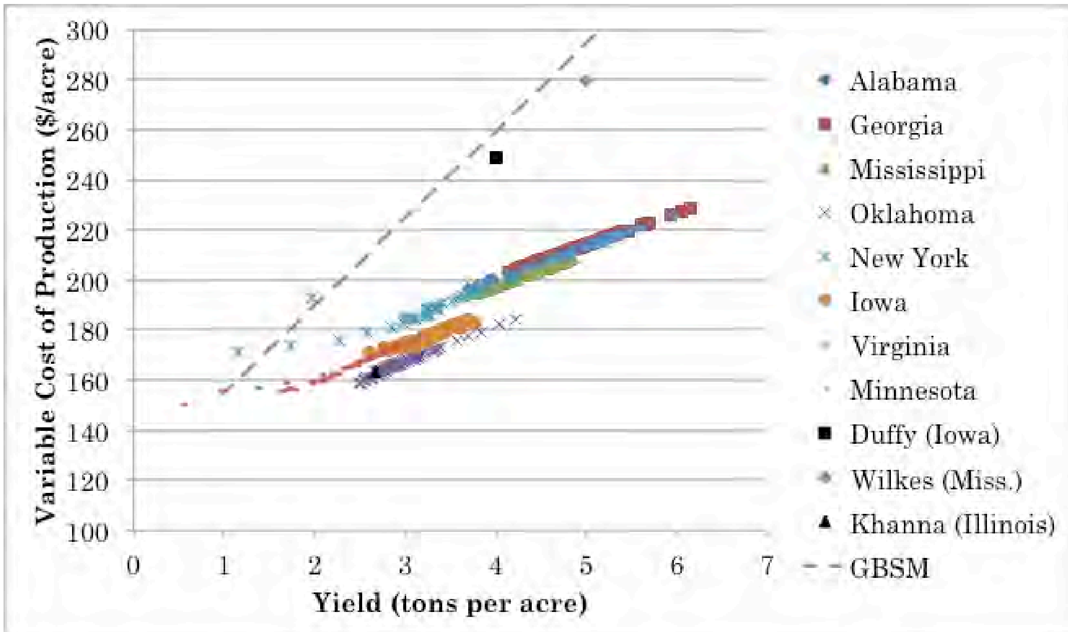


Figure 21. Variable production costs versus yield by region (Parker, 2011)

3.1.2 AGRICULTURAL RESIDUES

Agricultural residues are straws, stovers and other plant components remaining in the field after harvest of the crop. They play a role in maintaining soil health and preventing erosion (Lal, 2009; Wilhelm *et al.,* 2007). Limited removal of the residues has been proposed as a source of biomass. The scale of this resource potential depends on how much excess residues exist beyond what is required for soil maintenance, or on the existence of an economic alternative for providing the soil maintenance functions.

Muth *et al* (2012) provides the modeling basis for sustainable removal of the residues. Residues are available only if their removal will not increase soil erosion beyond the tolerable soil loss limit or cause soil organic carbon metrics to decline. This method has been questioned because its metrics for sustainability are weak, but it is a good estimate of maximum possible potential. At high prices, the BT2 estimate approaches this maximum.

3.1.3 FOREST RESIDUES

Woody biomass is available from forestry operations, and can come from three sources – integrated harvesting operations, "other forest removals," and mill residues. Residues are also available from "other forest removals" including urban land clearing and cultural operations. Integrated harvesting operations produce residues as part of the management of the forest to produce high value timber products. Costs for this woody biomass are estimated based on the cost of road-siding and chipping, as well as a fraction of historical stumpage fees for the removal of small trees.

The BT2 forest residue assessment comes from the US Forest Service and is a fair assessment. One critique is that it requires historical logging operations in a region as a screen for whether the forests will be managed. This leads to ignoring some potentially important resources such as the beetle-kill region in Colorado and some overstocked forests in the East. On the other hand, in a resource assessment by the Union of Concerned Scientists (2012), "other forest removals" and thinnings were excluded due to concerns about the climate impact of whole-tree removal. These residue categories are an area for focused study based on a life-cycle assessment, which needs to account for the dynamics of forest growth and fire risk. Leaving out these categories from potential estimates is conservative.

3.1.4 CONVENTIONAL WOOD

Wood production for the pulp industry could be expanded or diverted to energy production if the price of biomass for energy is high enough. The BT2 estimate comes from Skog *et al* (2010). The quantity of pulpwood that would become available at higher prices from both increases in supplies and decreases in demand from pulp mills in response to the price shift were found using estimates of the elasticity of pulpwood supply. At a county level, increases in pulpwood supply are limited to not exceed annual timber growth. Displacement of current pulpwood uses is also limited to below 20% of 2007 use due to uncertainties in the elasticity estimates, especially the range over which they are valid.

3.1.5 MUNICIPAL WASTE

There is a significant resource of organic wastes that are currently disposed of in the municipal waste stream. The MSW resource is not fully counted in BT2, as only woody MSW resources are counted in BT2. Other resources that are not currently included could play a role. Of particular interest are food wastes and green wastes (yard wastes) that are already seeing some market in anaerobic digesters for energy production and waste diversion purposes. The scale of the current food waste and yard waste disposal is 30% of the wood waste stream.

Table 21. Comparison of 2030 Biomass Resource Assessments (Parker, 2014)

Feedstock	BT2 ($80/ton)	Khanna ($90/ton)	Muth (baseline)	Muth (all no till)	UCS ($60/ton)
Energy Crops	512	350-650			400
Stover and Straws	208	187-197	228.70	327.25	129
Other Ag Residues	26				26
Forest Residues	62				21
Pulpwood	24				-
Urban wood wastes	43				43

3.1.6 SUMMARY

The Billion Ton Study update is a generally good source for a reasonable estimate of long-run biomass supply in the United States, given the critiques mentioned above. Its estimates for the most part fall in line with other estimates that have been made Table 21. The principal objection is that the prices for biomass in BT2 are too low. The National Academies of Science's report on the Renewable Fuel Standard (RFS) has a significantly higher estimate of the price that biomass providers would be willing to accept. These numbers suggest that prices 10-50% higher would be required to deliver the resource potential in BT2 at $80/ton (Table 22).

Table 22. Required feedstock prices from NAS (2011) (Parker 2014)

Feedstock	Farmer's Willingness-to-Accept ($/dry ton)
Stover (CS)	$92
Stover-Alfalfa	$92
Alfalfa	$118
Switchgrass (MW)	$133
Switchgrass (MW LQ)	$126
Switchgrass (App)	$100
Switchgrass (SC)	$98
Miscanthus (MW)	$115
Miscanthus (MW LQ)	$119
Miscanthus (App)	$105
Wheat Straw	$75
SRWC	$89

3.2 Biomass transport costs

The cost of transporting biomass to biorefineries will depend on the optimal size of the biorefinery, the moisture content of the feedstock, the spatial layout of the resource, and the cost of trucking (fuel, etc). The Geospatial Bioenergy Systems Model (GBSM) optimizes the layout of the biofuels industry for a given resource base, set of conversion technologies, and fuel markets. In a case study of the 2022 RFS mandate, Parker found that the average transport cost for woody biomass was significantly higher than herbaceous biomass in an optimized system for producing biofuels. These are reasonable estimates for the average transport costs. They will be high for technologies that can operate at small scale, like anaerobic digestion, and they will be low for very large centralized production. They do match the conversion costs in terms of the assumed scale of the biorefineries.

Table 23. Biomass transport costs by feedstock type based on Parker (2012)

Feedstock Type	Avg. Transport Cost ($/dry ton)
Woody	26.71
Straws/grasses/stovers	9.89

3.3 Biomass conversion technologies

Biomass can be converted to fuels or electricity to serve all energy markets. Processes exist to convert biomass to compete in the gasoline market, the diesel market, the jet fuel market, the natural gas market and the electricity market. A few of these technologies are currently in use, but many bioenergy conversion technologies are not currently commercial. To assess the potential process efficiency and cost of these technologies, cost models are based on simulations of the biorefinery. These studies have obvious limitations but are the best available information. Table 3 shows a summary of conversion process efficiencies and costs.

Table 24. Summary of conversion technology performance and cost (Parker, 2014 based on Rhodes, 2005, and CEC cost of generation)

Pathway			Yield			Conversion Cost ($/dry ton)	
Feedstock Group	Conversion Technology	Fuel	Basis	Esti mate	Range	2020 est.	2020 range
Cellulosics	AD	NG	gge/ton	77.5	32-112	$185	167-205
Cellulosics	Gasification	NG	HHV	66%	66-73	$124	118-165
Cellulosics	IGCC	Electricity	HHV	32%	30-35%	$132	
Cellulosics	Solid fuel Combustion	Electricity	HHV	25%	20-35%	$120	94-172
Cellulosics	Enzymatic Hydrolysis	Ethanol	Theoretical Ethanol	76%	67-82%	$120	83-166
Cellulosics	F-T Diesel	Diesel	HHV	42%	39-50%	$185	115-220
Cellulosics	Fast Pyrolysis	Diesel	HHV	36%	24-50%	$80	50-103
Cellulosics	Fast Pyrolysis	Jet fuel	HHV	36%	24-50%	$80	50-103
Cellulosics	Fast Pyrolysis	Gasoline	HHV	36%	24-50%	$80	50-103
Lipids (biodiesel precursors)	Hydro-treatment	Diesel	gge/ton	256	267-305 gge/ton	$314	150-
Lipids (biodiesel precursors)	Hydro-treatment	Jet fuel	gge/ton	248	267-305 gge/ton	$345	75-150
Manure	AD	NG	gge/ton	87	55-111	$40	30-40

3.3.1 RENEWABLE METHANE

The production of methane or renewable natural gas from biomass can follow two potential routes: anaerobic digestion and gasification combined with methane synthesis. The choice between the two appears to be mainly driven by moisture content, feedstock biodegradability, and cost. Anaerobic digestion is a technology that is currently in use for waste and residue feedstocks such as manures, waste water, and food wastes. In these cases, anaerobic digestion is used largely as a waste management technology that happens to produce energy.

More sophisticated anaerobic digester processes are under development to maximize the energy yield. The gasification and synthesis route is not currently commercial. Commercial projects exist for coal gasification and synthesis to methane, which is a similar process (Kopyscinski, 2010).

Anaerobic digestion is a complex biological process with four steps: hydrolysis, acidogenesis, acetogenesis, and methanation. The carbohydrates, proteins, and fats in biomass are broken down into simple sugars, amino acids, and fatty acids during hydrolysis. Through acidogensis, acetogenesis and methanation, these hydrolysis products are converted to methane and carbon dioxide following a few different paths. The effectiveness of anaerobic digestion depends on the biodegradability of the feedstock. Feedstocks with high lignin content or crystalline cellulosic structure are difficult to break down. Pretreatment of these feedstocks to make the carbohydrates available to the hydrolase enzymes can lead to good yields (Chandra, 2012). The AD technology is modeled based on Krich *et al* (2005) for manures and Shafiei *et al* (2013) for cellulosic feedstocks. The yield of methane is highly variable with reports of between 85 and 550 m^3 of CH_4 per dry ton depending on feedstock and study. The 77.5 gge/ton value suggested corresponds to approximately 265 m^3 of CH_4 per dry ton and is the reported yield for wheat straw with pretreatment.

The gasification route breaks down biomass into a syngas comprised mainly of hydrogen and carbon monoxide in a hot oxygen starved environment. The syngas is then converted to methane through a series of three synthesis reactors. The process is reported to be highly efficient, converting approximately 66% of the energy content of biomass into methane. A small amount of co-product electricity and a high quality waste heat stream can make the overall efficiency approach 80% if it can be co-located with a heat load. Only a few studies have assessed the economics of this pathway. They estimate the cost of production between $2.55-3.65/gge at scales that seem reasonable in the next decade (Glassner, 2009; Tuna, 2014). Like most thermochemical PATHWAYS, the cost of the gasification route is heavily dependent on scale economies, with scale-up potentially leading to cost reductions of 20% or more.

3.3.2 CELLULOSIC ETHANOL

Ethanol production from cellulosic biomass is not currently a commercially viable technology. Estimates for the cost of production rely on a number of engineering studies with process-level modeling of the biorefinery. The majority of studies of cellulosic ethanol consider the biochemical pathway in which the cellulose and hemicellulose are converted to sugars through enzymatic hydrolysis and saccharification, and then fermented to make ethanol. Tao and Aden considered the thermochemical pathway via gasification and synthesis, and found the cost and performance to be similar to the biochemical pathway at a scale of 45 million gallons of ethanol per year (Tao and Aden, 2009). The biochemical route is taken to be the model cellulosic ethanol technology due to the larger base of supporting literature. The thermochemical pathway may prove to be the better technology in certain cases, but given the overall uncertainty in the technology costs and performance the performance of the thermochemical pathway is assumed to fall within the study range.

The biochemical pathway begins with feedstock pretreatment to make the cellulose available to the enzymes. There are a number of techniques under research and development for this pretreatment, including dilute acid hydrolysis, ammonia fiber explosion, liquid hot water, and steam explosion. In the process of exposing the cellulose, the hemicellulose is broken into its component sugars (xylose, arabinose, etc.). The exposed cellulose is then converted to glucose with cellulase enzymes. Glucose is fermented to ethanol and the 5-carbon sugars are fermented to ethanol either in a combined reactor using recombinant *Zymomonas mobilis* or in separate reactors using yeast for the C6 sugars and *Z. mobilis* for the C5 sugars. In the advanced designs of Laser *et al.* (2010) and Hamelinck *et al.* (2005) a consolidated bioprocessing (CBP) approach is taken where all biological conversions (enzyme production, enzymatic hydrolysis, and fermentation) occur in the same reactor. This design is attractive but the catalyst to make it possible has yet to be identified. In most designs, the lignin is separated from the beer, dried, and combusted to produce steam and electricity for the biorefinery, with some net export of electricity.

There is a large range of projected costs using "current" technology. There are three main sources of variation in the costs estimates. First is the expected yield of ethanol from cellulosic material. Estimates range from 52.4 gallons per ton to 76.4 gallons of ethanol per dry ton of switchgrass or corn stover. This variation is due to difference in the performance of the pretreatment, cellulase enzymes, and fermentation organisms each study assumes. Dutta *et al.* (2010) and Kazi *et al.* (2010) use experimentally verified performance measures and show the highest production costs. The second source of variation is the capital investment required. This is due to the variety of configurations studied, as well as yield differences. Within the same study, capital costs varied by 42% due to different configurations of pretreatment, hydrolysis, fermentation, and distillation (Kazi *et al.*, 2010). The third factor is the variable operating cost – mainly the cost of cellulase enzymes. For example, Aden (2008) projects cellulase enzymes available at $0.32/gal of ethanol where Kazi *et al.* (2010) puts the cost at $1.05/gal. Also of interest is that the estimate for year 2000 technology in Wooley *et al.* (1999) falls below the more recent estimates of current costs, demonstrating that as more is learned about these technologies, limitations are identified that lead to additional costs.

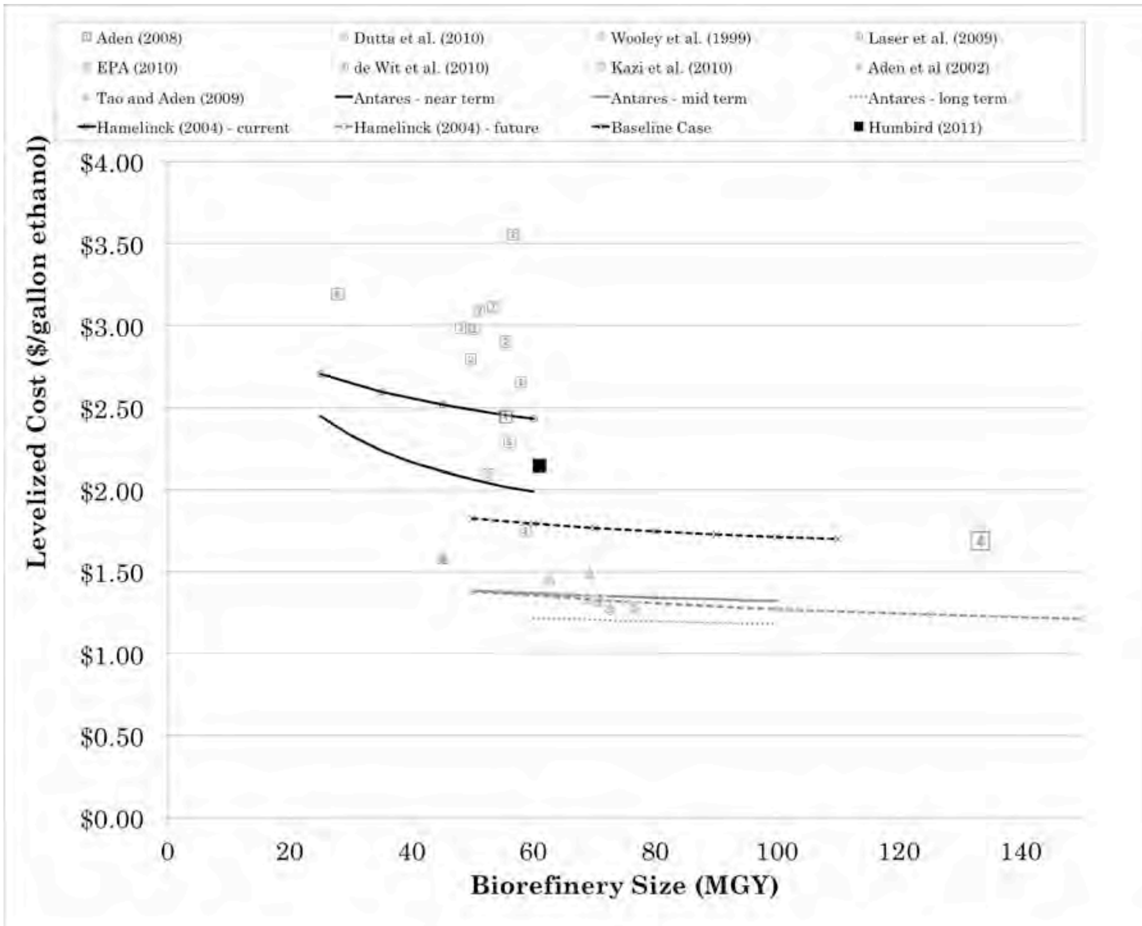


Figure 22. Comparison of estimated levelized cost of production for cellulosic ethanol. Near term technology assessments are represented by squares, mid-term technology (7-15 years ahead) are triangles; long-term projections are shown as diamonds. (Parker, 2014)

The yield for biochemical ethanol is presented as a percentage of maximum theoretical yield. The maximum theoretical yield is the production of ethanol if all the component sugars in the cellulose and hemicellulose fractions of biomass are fully converted to ethanol. The theoretical yield ranges from 73 to 122 gallons per dry ton for the feedstocks considered here. The range shrinks to 100-117 gallons per ton if considering only feedstocks with a large potential (corn stover, wheat straw, energy crops, and woody resources). Studies show a range of actual yields between 67% and 82% of the maximum theoretical yield. The equation for calculating ethanol yield for a given feedstock composition is below.

$$\boldsymbol{Yield}\left(\frac{\boldsymbol{gal}}{\boldsymbol{ton}}\right) = (\mathbf{1.11} * \boldsymbol{Cellulose\ fraction} * \%\boldsymbol{cellulose\ conversion} + \mathbf{1.136} * \boldsymbol{Hemicellulose\ fraction} * \%\ \boldsymbol{hemicellulose\ conversion}) * \mathbf{0.51} * \mathbf{2000/6.55}$$

Where: Cellulose fraction = fraction of dry matter that is cellulose

Hemicellulose fraction = fraction of dry matter that is hemicellulose

$$\%\ \textit{cellulose conversion} = \frac{\boldsymbol{actual\ yield\ of\ cellulose\ to\ ethanol}}{\boldsymbol{theoretical\ yield}}$$

$$\%\ \textit{hemicellulose conversion} = \frac{\boldsymbol{actual\ yield\ of\ hemicellulose\ to\ ethanol}}{\boldsymbol{theoretical\ yield}}$$

3.3.3 FISCHER-TROPSCH DISTILLATE FUELS

Thermochemical conversion of biomass to fuels can take many routes. The Fischer-Tropsch synthesis process is among the most studied and furthest developed. Commercial facilities exist or have existed in the past for production of F-T fuels from both coal and natural gas. Advances in biomass gasifiers and the optimizing of gas clean-up and the F-T synthesis process for biomass-based synthesis gas will be required for commercialization. A number of biomass gasifier configurations have been studied, the details of which can be found in Hamelinck *et al.* (2004), Larson *et al.* (2009) and Swanson *et al.* (2010).

There is a large range in the projected cost for current technology F-T diesel production. This represents disagreement on which technologies are current and which are unproven, as well as difference in design. The Swanson study states that hot gas clean up (tar cracking) is not yet commercial while all other studies employ it is if it were commercial. The Antares study uses an indirectly fired atmospheric gasifier, while most others use pressurized oxygen blown directly fired gasifiers. In projecting future technology versus current technology, Hamelinck *et al.* (2004) foresees no changes in the design but projects reductions in capital and operating costs due to incremental improvements and increases in scale. Larson *et al.* (2009) presents a case with mature technology where a once-through configuration is designed for greater electricity production than found in other studies. The EPA projection is significantly lower compared to other studies at similar scale and timeframe (EPA, 2010). Little information was provided to support this estimate.

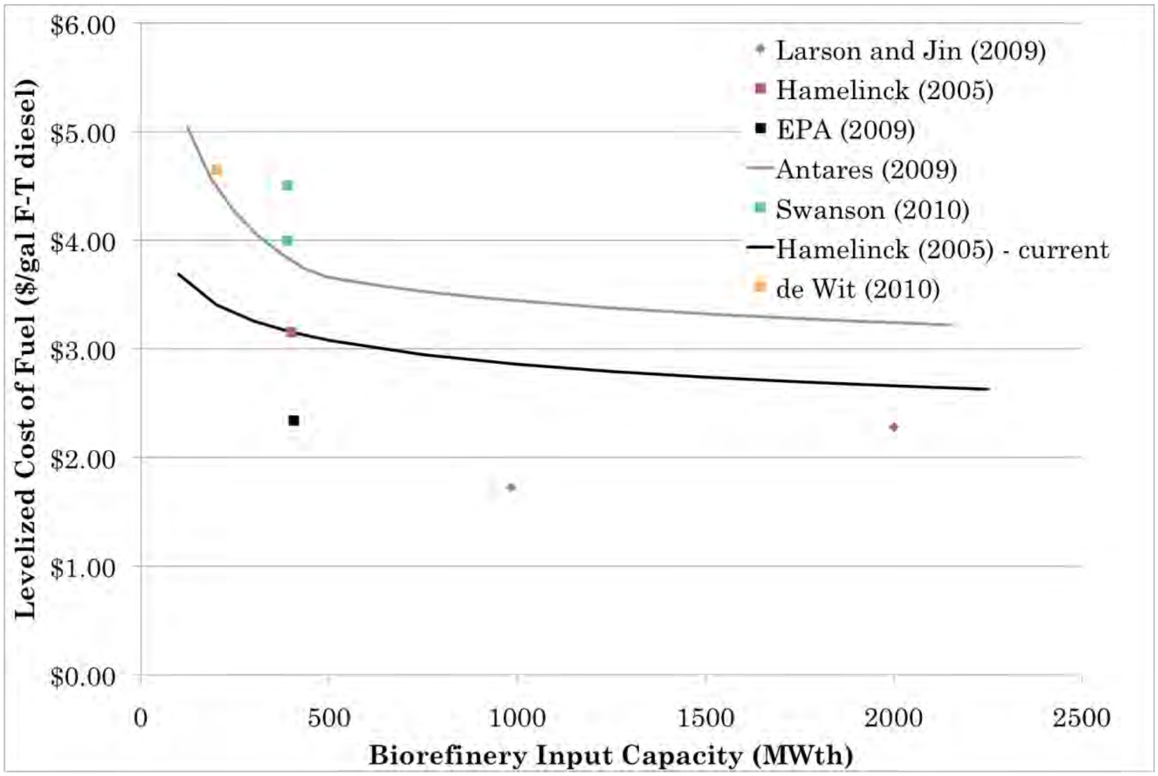


Figure 23. Comparison of estimated levelized cost of production for Fischer-Tropsch diesel technologies. Near term technology assessments are represented by squares, mid-term technology (7-15 years ahead) are triangles; long-term projections are shown as diamonds. (Parker, 2014)

3.3.3.1 Fast pyrolysis of cellulosic biomass to hydrocarbons

Fast pyrolysis of cellulosic biomass generates a crude bio-oil that then must be upgraded using petroleum refinery technologies. This technology can produce a range of hydrocarbons with some control over the fraction that goes to gasoline, diesel, and jet fuel. Upgrading this method requires hydrogen, and there have been two designs considered for fast pyrolysis; one in which he hydrogen is produced from the bio-oil itself and another in which the hydrogen is produced from natural gas. The technologies shown here all assume the hydrogen is produced from the bio-oil to simplify accounting in the model. One fast pyrolysis biorefinery at pre-commercial scale began operations in 2013. Wright *et al* (2010) found that hydrocarbon fuels could be produced via fast pyrolysis at between \$2.60 and \$3.75 per gallon.

3.3.3.2 Lipid (fats and oils) to diesel or jet fuels

Conversion of lipids to diesel replacement fuels is currently performed using a transesterfication process to create fatty acid methyl esters (FAME) or conventional biodiesel. Emerging technologies seek to create a hydrocarbon fuel that can be freely blended with diesel through a hydrotreatment process. These two technologies can be modeled as competitors for the lipid feedstocks, or one can be chosen as representative. The hydrotreatment technology is presented here due to its flexibility in meeting diesel and jet demands.

Techno-economic analyses of the hydrotreatment process are based on the UOP/Eni process (Holmgren *et al.*, 2007). In the process, the lipids and hydrogen pass through a hydroprocessing unit in which the oxygen is stripped from the lipids through decarboxylation and hydrodeoxygenation reactions. The resulting products are a combination of "green diesel" and lighter hydrocarbons (naphtha and/or propane) with byproducts of water and carbon oxides (CO and CO_2). The green diesel fuel is reported to have a number of desirable properties – high cetane number (70-90), energy density equivalent to ultra-low sulfur diesel, sulfur content of less than 1 ppm (USLD < 10 ppm sulfur), and good stability. Holmgren *et al* (2007) identify the potential to use green diesel as a premium blendstock allowing for the use of lower valued light-cycle oil as part of a diesel blend.

The Antares model considers two configurations for the hydrotreatment process; one as a stand-alone unit within a petroleum refinery and one as co-processing within the same hydroprocessing units as petroleum products. The stand-alone units have higher capital costs but lower hydrogen demand and higher green diesel yields. The coprocessing design has higher hydrogen requirements because the hydroprocessing units for crude oil operate in conditions that favor the hydrodeoxygenation reactions over the decarboxylation reactions, which consume 3.75 times the hydrogen per oxygen removed (Antares, 2009).

The EPA's estimate of the cost of hydrotreament-based diesel is slightly higher than the Antares model. The EPA model is based on the stand-alone design but assumes higher hydrogen consumption (0.224 lb/gal compared to 0.117 lb/gal) (EPA, 2010). The higher hydrogen cost is offset somewhat by an assumed lower capital and operating expenses besides hydrogen.

Pearlson *et al* (2013) provided an updated estimate with a distinction between diesel and jet fuel facilities. The jet fuel facilities require more hydrogen and produce less distillate fuel overall, as more fuel falls in the naphtha range. The costs are significantly higher than earlier estimates.

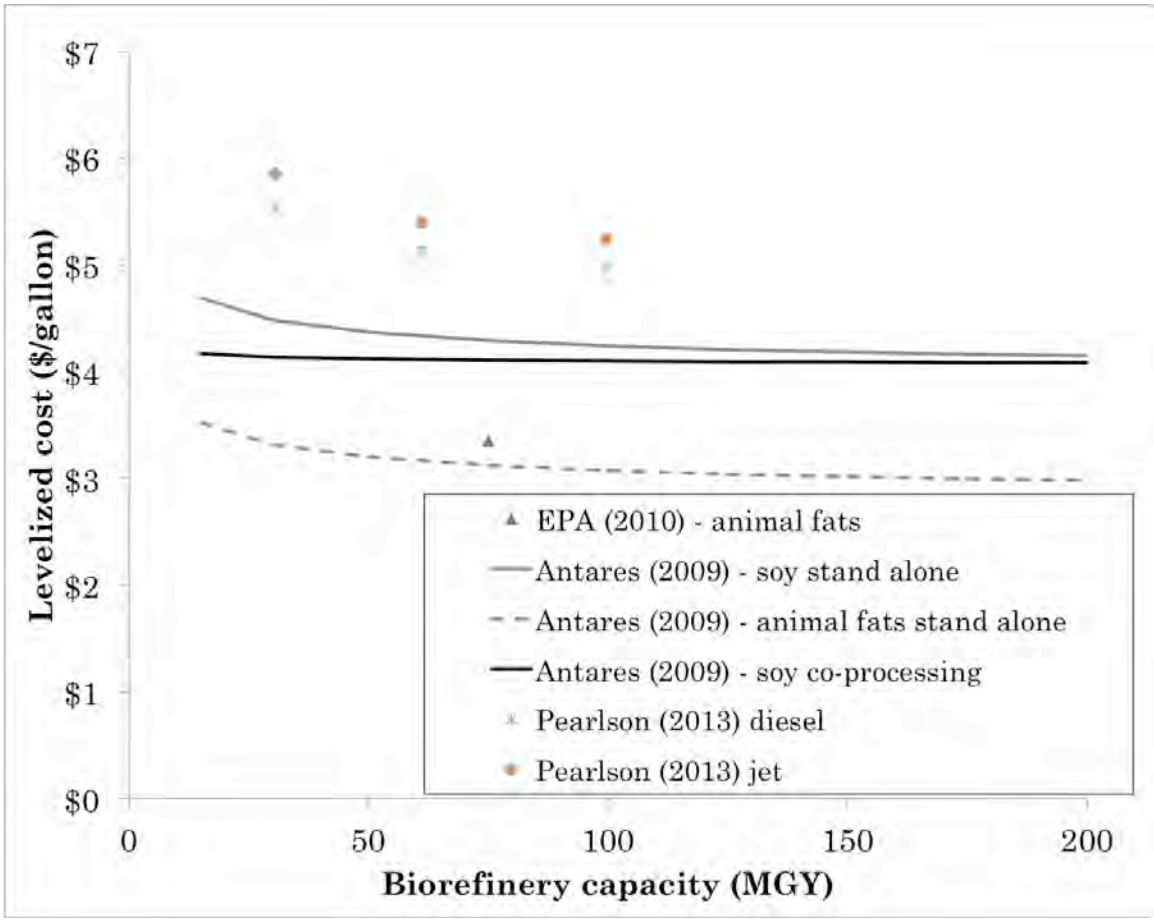


Figure 24. Comparison of estimated levelized cost of production for hydrotreatment of lipids to distillate fuels. All estimates are for mid-term technologies (7 – 15 years ahead) (Parker, 2014)

Table 25. Biomass feedstock composition and theoretical ethanol yield

Feedstock	PATHWAYS Category	HHV (GJ/tonne)	Cellulose	Hemi-cellulose	Lignin	Theoretical ethanol yield (gal/ton)	Theoretical ethanol yield (gge/ton)
Barley straw	Solids	16.1	33%	20%	17%	93	61
Corn stover	Solids	17.1	36%	23%	19%	104	68
Oat straw	Solids	17.9	38%	23%	13%	106	70
Sorghum stubble	Solids	17.6	35%	24%	25%	103	68
Wheat straw	Solids	17.9	34%	23%	14%	100	66
Annual energy crop	Solids	17.6	49%	18%	23%	117	77
Perennial grasses	Solids	18.1	32%	25%	18%	100	66
Woody crops	Solids	19.5	45%	19%	26%	110	72
Composite	Solids	19.0	45%	22%	28%	116	76
Removal residue	Solids	19.0	45%	22%	28%	116	76
Conventional wood	Solids	19.0	45%	22%	28%	116	76
Treatment thinnings	Solids	19.0	45%	22%	28%	116	76
Secondary mill residue	Solids	20.2	45%	22%	28%	116	76
Primary mill residue	Solids	20.2	45%	22%	28%	116	76
Urban wood waste other	Solids	18.4	45%	19%	26%	110	72
Urban wood MSW	Solids	18.4	45%	19%	26%	110	72
Cotton gin trash	Solids	16.0	41%	15%	29%	98	64
Cotton residue	Solids	16.0	31%	11%	28%	73	48
Manure	Biogas Precursors					-	-
Orchard and vineyard prunings	Solids	17.8	45%	19%	26%	110	72
Rice hulls	Solids	16.8	40%	19%	25%	103	68
Rice straw	Solids	15.1	39%	20%	23%	102	67
Sugarcane trash	Solids	17.8	45%	25%	18%	122	80
Wheat dust	Solids	16.8	36%	18%	16%	94	62

Fuelwood	Solids	19.0	45%	22%	28%	116	76
Mill residue	Solids	20.2	45%	22%	28%	116	76
Pulping liquors	Solids	15.0				-	-
Existing forest MSW	Solids	18.4	45%	19%	26%	110	72
Existing biodiesel precursors	Biodiesel Precursors					-	-
Existing Agricultural MSW	Solids	14.0	50%	7%	11%	99	65

4 Biomass References

Aden, A. (2008). Biochemical Production of Ethanol from Corn Stover : 2007 State of Technology Model Biochemical Production of Ethanol from Corn Stover : 2007 State of Technology Model, (May).

Aden, A., Ruth, M., Ibsen, K., Jechura, J., Neeves, K., Sheehan, J., … Lukas, J. (2002). *Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehyd*.

Arbogast, S., Bellman, D., Paynter, J. D., & Wykowski, J. (2013). Advanced biofuels from pyrolysis oil…Opportunities for cost reduction. *Fuel Processing Technology*, *106*, 518–525. doi:10.1016/j.fuproc.2012.09.022

Antares. (2009). National Biorefinery Siting Model Draft Final Report – Task 2 Technologies for Biofuels Production.

Bledzki, A. K., Mamun, A. a., & Volk, J. (2010). Physical, chemical and surface properties of wheat husk, rye husk and soft wood and their polypropylene composites. *Composites Part A: Applied Science and Manufacturing*, *41*(4), 480–488. doi:10.1016/j.compositesa.2009.12.004

Brown, T. R., Thilakaratne, R., Brown, R. C., & Hu, G. (2013). Regional differences in the economic feasibility of advanced biorefineries: Fast pyrolysis and hydroprocessing. *Energy Policy*, *57*, 234–243. doi:10.1016/j.enpol.2013.01.058

Chandra, R., Takeuchi, H., & Hasegawa, T. (2012). Methane production from lignocellulosic agricultural crop wastes: A review in context to second generation of biofuel production. *Renewable and Sustainable Energy Reviews*, *16*(3), 1462–1476. doi:10.1016/j.rser.2011.11.035

Demirbas, A. (2002). Pyrolysis and steam gasification processes of black liquor, *43*, 877–884.

Duffy, M. D., & Vontalge, A. L. (1999). Estimated costs of crop production in Iowa, 1999.

Dutta, A., Dowe, N., Ibsen, K. N., Schell, D. J., & Aden, A. (2009). An economic comparison of different fermentation configurations to convert corn stover to ethanol using Z. mobilis and Saccharomyces. *Biotechnology Progress*, *26*(1), 64–72. doi:10.1002/btpr.311

Dutta, A., Talmadge, M., Hensley, J., Worley, M., Dudgeon, D., Barton, D., … Hess, J. (2011). *Process Design and Economics for Conversion of Lignocellulosic Biomass to Ethanol Thermochemical Pathway by Indirect Gasification and Mixed Alcohol Synthesis*.

Dwivedi, P., Alavalapati, J. R. R., & Lal, P. (2009). Cellulosic ethanol production in the United States: Conversion technologies, current production status, economics, and emerging developments. *Energy for Sustainable Development*, *13*(3), 174–182. doi:10.1016/j.esd.2009.06.003

Foust, T. D., Aden, A., Dutta, A., & Phillips, S. (2009). An economic and environmental comparison of a biochemical and a thermochemical lignocellulosic ethanol conversion processes. *Cellulose*, *16*(4), 547–565. doi:10.1007/s10570-009-9317-x

Gassner, M., & Maréchal, F. (2009). Thermo-economic process model for thermochemical production of Synthetic Natural Gas (SNG) from lignocellulosic biomass. *Biomass and Bioenergy*, *33*(11), 1587–1604. doi:10.1016/j.biombioe.2009.08.004

Hamelinck, C., Faaij, a, Denuil, H., & Boerrigter, H. (2004). Production of FT transportation fuels from biomass; technical options, process analysis and optimisation, and development potential. *Energy*, *29*(11), 1743–1771. doi:10.1016/j.energy.2004.01.002

Hamelinck, C. N. (2004). *OUTLOOK FOR ADVANCED BIOFUELS*.

Hamelinck, C. N., Hooijdonk, G. van, & Faaij, A. P. C. (2005). Ethanol from lignocellulosic biomass: techno-economic performance in short-, middle- and long-term. *Biomass and Bioenergy*, *28*(4), 384–410. Retrieved from http://www.sciencedirect.com/science/article/B6V22-4F320KP-1/1/6f03b6163c5c4128eafef42d9b74f8b3

Huang, H.-J., Ramaswamy, S., Al-Dajani, W., Tschirner, U., & Cairncross, R. a. (2009). Effect of biomass species and plant size on cellulosic ethanol: A comparative process and economic analysis. *Biomass and Bioenergy*, *33*(2), 234–246. doi:10.1016/j.biombioe.2008.05.007

Humbird, D., Davis, R., Tao, L., Kinchin, C., Hsu, D., Aden, A., … Dudgeon, D. (2011). *Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol*.

Jeoh, T. (1998). Steam Explosion Pretreatment of Cotton Gin Waste for Fuel Ethanol Production by.

Kazi, F. K., Fortman, J. a., Anex, R. P., Hsu, D. D., Aden, A., Dutta, A., & Kothandaraman, G. (2010). Techno-economic comparison of process technologies for biochemical ethanol production from corn stover. *Fuel*, *89*, S20–S28. doi:10.1016/j.fuel.2010.01.001

Khanna, M., Chen, X., Huang, H., & Onal, H. (2010). SUPPLY OF CELLULOSIC BIOFUEL FEEDSTOCKS AND Regional Production Patterns. In *Agricultural & Applied Economics Assiociation*.

Kopyscinski, J., Schildhauer, T. J., & Biollaz, S. M. a. (2010). Production of synthetic natural gas (SNG) from coal and dry biomass – A technology review from 1950 to 2009. *Fuel*, *89*(8), 1763–1783. doi:10.1016/j.fuel.2010.01.027

Kwiatkowski, J. R., McAloon, A. J., Taylor, F., & Johnston, D. B. (2006). Modeling the process and costs of fuel ethanol production by the corn dry-grind process. *Industrial Crops and Products*, *23*(3), 288–296. doi:10.1016/j.indcrop.2005.08.004

Liu, G., Larson, E. D., Williams, R. H., Kreutz, T. G., & Guo, X. (2011). Making Fischer−Tropsch Fuels and Electricity from Coal and Biomass: Performance and Cost Analysis. *Energy & Fuels*, *25*(1), 415–437. doi:10.1021/ef101184e

Marsh, M., Officer, C. E., Krich, K., Krich, K., Augenstein, D., Benemann, J., … Salour, D. (2005). Biomethane from Dairy Waste A Sourcebook for the Production and Use of, (July).

Muth, D. J., Bryden, K. M., & Nelson, R. G. (2013). Sustainable agricultural residue removal for bioenergy: A spatially comprehensive US national assessment. *Applied Energy*, *102*, 403–417. doi:10.1016/j.apenergy.2012.07.028

National Academies of Sciences. (2011). *Renewable Fuel Standard : Potential Economic and Environmental Effects of U . S . Biofuel Policy Committee on Economic and Environmental Impacts of Increasing Biofuels*.

Pearlson, M., Wollersheim, C., Hileman, J., & August, R. (2013). Modeling and Analysis A techno-economic review of hydroprocessed renewable esters and fatty acids for jet fuel production, 89–96. doi:10.1002/bbb

Piccolo, C., & Bezzo, F. (2009). A techno-economic comparison between two technologies for bioethanol production from lignocellulose. *Biomass and Bioenergy*, *33*(3), 478–491. doi:10.1016/j.biombioe.2008.08.008

Pütün, A. E., Özbay, N., Önal, E. P., & Pütün, E. (2005). Fixed-bed pyrolysis of cotton stalk for liquid and solid products. *Fuel Processing Technology*, *86*(11), 1207–1219. doi:10.1016/j.fuproc.2004.12.006

Rhodes, J. S., & Keith, D. W. (2005). Engineering economic analysis of biomass IGCC with carbon capture and storage. *Biomass and Bioenergy*, *29*(6), 440–450. doi:10.1016/j.biombioe.2005.06.007

Searle, S. Y., & Malins, C. J. (2014). Will energy crop yields meet expectations? *Biomass and Bioenergy*, 1–10. doi:10.1016/j.biombioe.2014.01.001

Shafiei, M., Kabir, M. M., Zilouei, H., Sárvári Horváth, I., & Karimi, K. (2013). Techno-economical study of biogas production improved by steam explosion pretreatment. *Bioresource Technology*, *148*, 53–60. doi:10.1016/j.biortech.2013.08.111

Silverstein, R. a, Chen, Y., Sharma-Shivappa, R. R., Boyette, M. D., & Osborne, J. (2007). A comparison of chemical pretreatment methods for improving saccharification of cotton stalks. *Bioresource Technology*, *98*(16), 3000–11. doi:10.1016/j.biortech.2006.10.022

Swanson, R. M., Platon, A., Satrio, J. a., & Brown, R. C. (2010). Techno-economic analysis of biomass-to-liquids production based on gasification. *Fuel*, *89*, S11–S19. doi:10.1016/j.fuel.2010.07.027

Tunå, P., & Hulteberg, C. (2014). Woody biomass-based transportation fuels – A comparative techno-economic study. *Fuel*, *117*, 1020–1026. doi:10.1016/j.fuel.2013.10.019

Union of Concerned Scientists (UCS). (2012). Clean Power and Fuel — If Handled Right.

Villanueva Perales, a. L., Reyes Valle, C., Ollero, P., & Gómez-Barea, a. (2011). Technoeconomic assessment of ethanol production via thermochemical conversion of biomass by entrained flow gasification. *Energy*, *36*(7), 4097–4108. doi:10.1016/j.energy.2011.04.037

Wilkes, H. L., & Jackson, M. S. Jamie L. Whitten Plant Materials Center 2007 Annual Technical Report.

Wooley, R., Ruth, M., Sheehan, J., Majdeski, H., & Galvez, A. (1999). Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Futuristic Scenarios Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current D, (July).

Wright, M., Daugaard, D., Satrio, J., & Brown, R. (2010). Techno-Economic Analysis of Biomass Fast Pyrolysis to Transportation Fuels. *Fuel*, (November). Retrieved from http://www.sciencedirect.com/science/article/pii/S0016236110003765

Wright, M. M., Daugaard, D. E., Satrio, J. A., & Brown, R. C. (2010). Techno-economic analysis of biomass fast pyrolysis to transportation fuels. *Fuel*, *89*(null), S2–S10. doi:10.1016/j.fuel.2010.07.029

Yu, J., Zhang, J., He, J., Liu, Z., & Yu, Z. (2009). Combinations of mild physical or chemical pretreatment with biological pretreatment for enzymatic hydrolysis of rice hull. *Bioresource Technology*, *100*(2), 903–8. doi:10.1016/j.biortech.2008.07.025

5 Stock Characterization and Demand Projection References

Sector	Subsector	Activity Sources		Baseline Efficiency and Stock Characterization Sources	New Technology Sources	Cost Sources	Calibration Sources
Residential	Water Heating	2009 RASS		2009 RASS; California Appliance Standards	DOE Residential Heating Products Final Rule Technical Support Documents	DOE Residential Heating Products Final Rule Technical Support Documents	CEC Energy Demand Forecast
Residential	Space Heating	2009 RASS		2009 RASS; California Appliance Standards	DOE Life Cycle Cost Spreadsheet DHE Equipment; DOE Furnace and Central Air Conditioners and Heat Pump Life Cycle Cost and Payback Period Spreadsheets	DOE Life Cycle Cost Spreadsheet DHE Equipment; DOE Furnace and Central Air Conditioners and Heat Pump Life Cycle Cost and Payback Period Spreadsheets	CEC Energy Demand Forecast
Residential	Air Conditioning	2009 RASS		2009 RASS; California Appliance Standards; 2013 Navigant EE Potential Model	2013 Navigant EE Potential Model	2013 Navigant EE Potential Model	CEC Energy Demand Forecast

Sector	Subsector	Activity Sources		Baseline Efficiency and Stock Characterization Sources	New Technology Sources	Cost Sources	Calibration Sources
Residential	Lighting	Calculated from CEC Demand Forecast and residential sq. footage projections		2013 California Building Energy Efficiency Standards: Draft Measure Information Template - Residential Lighting; 2010 Lighting Market Characterization	DOE: Energy Savings Potential of Solid-State Lighting in General Illumination Applications	DOE: Energy Savings Potential of Solid-State Lighting in General Illumination Applications	CEC Energy Demand Forecast
Residential	Misc.	Calculated from CEC Energy Demand Forecast		2009 RASS; DOE Pool Heater Life Cycle Cost Model; DOE Clothes Washer Life-Cycle Cost and Payback Period Analysis; Draft DOE Oven Life Cycle Cost Spreadsheet; DOE Dishwasher Life Cycle Cost Spreadsheet; DOE National Impact Analysis: Refrigerators and Freezers; DOE Clothes Dryer Lifecycle Cost Model	DOE Pool Heater Life Cycle Cost Model; DOE Clothes Washer Life-Cycle Cost and Payback Period Analysis; Draft DOE Oven Life Cycle Cost Spreadsheet; DOE Dishwasher Life Cycle Cost Spreadsheet; DOE National Impact Analysis: Refrigerators and Freezers; DOE Clothes Dryer Lifecycle Cost Model	DOE Pool Heater Life Cycle Cost Model; DOE Clothes Washer Life-Cycle Cost and Payback Period Analysis; Draft DOE Oven Life Cycle Cost Spreadsheet; DOE Dishwasher Life Cycle Cost Spreadsheet; DOE National Impact Analysis: Refrigerators and Freezers; DOE Clothes Dryer Lifecycle Cost Model	CEC Energy Demand Forecast
Transportation	Light Duty Vehicles	CARB EMFAC		CARB EMFAC; ARB LDV Off-Road Model	"Transitions to Alternative Vehicles and Fuels", National Academies Press, 2013	"Transitions to Alternative Vehicles and Fuels", National Academies Press, 2013	
Transportation	Passenger Rail	National Transit Database, Federal Transit Administration, 2011		National Transit Database, Federal Transit Administration, 2011	EIA	APTA U.S. Average New Vehicle Costs for 2010 and 2011 Vehicles by Type	

Sector	Subsector	Activity Sources		Baseline Efficiency and Stock Characterization Sources	New Technology Sources	Cost Sources	Calibration Sources
Transportation	Bus	National Transit Database, Federal Transit Administration, 2011		National Transit Database, Federal Transit Administration, 2011; AQMD Emissions Factors; 2013 APTA Vehicle Database	Department of Transportation Fuel Cell Bus Life Cycle Model: Base Case and Future Scenario Analysis	Department of Transportation Fuel Cell Bus Life Cycle Model: Base Case and Future Scenario Analysis	
Transportation	Commercial Aviation	US DOT: Research and Innovative Technology Administration; Bureau of Transportation Statistics		US DOT: Research and Innovative Technology Administration; Bureau of Transportation Statistics	US DOT: Research and Innovative Technology Administration; Bureau of Transportation Statistics	EIA Annual Energy Outlook 2013: Air Travel Energy Use	CARB Emissions Inventory
Transportation	General Aviation	2010 General Aviation Statistical Databook and Industry Outlook		2010 General Aviation Statistical Databook and Industry Outlook			CARB Emissions Inventory
Transportation	Freight Rail	CARB Vision Off-Road Model		CARB Vision Off-Road Model	CARB Vision Off-Road Model		AQD Emissions Inventories; CARB Emissions Inventory
Transportation	Ocean Going Vessels	CARB Vision Off-Road Model		CARB Vision Off-Road Model	CARB Vision Off-Road Model		AQD Emissions Inventories; CARB Emissions Inventory
Transportation	Heavy Duty Trucking	CARB EMFAC		CARB EMFAC	Assessment of Fuel Economy Technologies for Medium- and Heavy-Duty Vehicles; 2012 MODEL YEAR ALTERNATIVE FUEL VEHICLE (AFV) GUIDE	Assessment of Fuel Economy Technologies for Medium- and Heavy-Duty Vehicles	AQD Emissions Inventories; CARB Emissions Inventory

Sector	Subsector	Activity Sources		Baseline Efficiency and Stock Characterization Sources	New Technology Sources	Cost Sources	Calibration Sources
Transportation	Commercial Harbor Craft	CARB Vision Off-Road Model		CARB Vision Off-Road Model;	CARB Vision Off-Road Model		AQD Emissions Inventories; CARB Emissions Inventory
Transportation	Off-Road	2011 CARB Off-Road Diesel Emissions Inventory Model		2011 CARB Off-Road Diesel Emissions Inventory Model			EMISSIONS INVENTORY DEVELOPMENT FOR IN-USE OFF-ROAD EQUIPMENT
Agriculture	Other	CEC Demand Forecasts; EIA Diesel Farm Fuel Sales		N/A	N/A	N/A	CEC Demand Forecast (Gas and Electricity); AQD Emissions Inventories
Oil & Gas Extraction	Other	CEC Demand Forecasts; CARB Gasoline Sales Estimates		N/A	N/A	N/A	CEC Demand Forecast (Gas and Electricity); AQD Emissions Inventories
Petroleum Refining	Other	CEC Demand Forecasts		N/A	N/A	N/A	CEC Demand Forecast (Gas and Electricity); AQD Emissions Inventories
Transportation, Communication, and Utilities	Other	CEC Demand Forecasts		N/A	N/A	N/A	CEC Demand Forecast (Electricity); AQD Emissions Inventories

Sector	Subsector	Activity Sources		Baseline Efficiency and Stock Characterization Sources	New Technology Sources	Cost Sources	Calibration Sources
Industrial	Unspecified (by industry)			N/A	N/A	N/A	CEC Demand Forecasts; AQD Emissions Inventories
Commercial	Lighting	CEC Demand Forecasts		2010 Lighting Market Characterization	DOE: Energy Savings Potential of Solid-State Lighting in General Illumination Applications	DOE: Energy Savings Potential of Solid-State Lighting in General Illumination Applications	CEC Energy Demand Forecast
Commercial	All other Sectors	CEC Demand Forecasts; California Commercial End-Use Survey;		2013 Navigant EE Potential Model	2013 Navigant EE Potential Model	2013 Navigant EE Potential Model	CEC Energy Demand Forecast

6 References

Argonne National Laboratory *Natual Gas Vehicles: Status, Barriers, and Opportunities.* Argonne, Illinois, s.n., 2010.

EIAAnnual Energy Outlook 2013: Natural Gas Supply Disposition and Prices. *United States Energy Information Administration.* [Online]2013. http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=0-AEO2013&table=13-AEO2013&region=0-0&cases=ref2013-d102312a.

Gas Technology Institute *Small Scale Liquefier Development.* Washington, D.C., U.S. Department of Energy: Energy Efficiency and Renewable Energy Technical Committee, 2004.

United States Energy Information Administration Washington D.C., s.n., 2013
.

Public Safety Power Shutoff (PSPS) / De-Energization

What is PSPS? History and Background

Over the last decade, California has experienced increased, intense, and record-breaking wildfires in Northern and Southern California. These fires have resulted in devastating loss of life and billions of dollars in damage to property and infrastructure. Electric utility infrastructure has historically been responsible for less than ten percent of reported wildfires; however, fires attributed to power lines comprise roughly half of the most destructive fires in California history. With the continuing threat of wildfire, utilities may proactively cut power to electrical lines that may fail in certain weather conditions to reduce the likelihood that their infrastructure could cause or contribute to a wildfire. This effort to reduce the risk of fires caused by electric infrastructure by temporarily turning off power to specific areas is called a Public Safety Power Shutoff (PSPS). However, a PSPS can leave communities and essential facilities without power, which brings its own risks and hardships, particularly for vulnerable communities and individuals. From 2013 to the end of 2019, California experienced over 57,000 wildfires (averaging 8,000 per year) and the three large energy companies conducted 33 PSPS de-energizations.

In 2012, the CPUC ruled that California Public Utilities Code Sections 451 and 399.2(a) give electric utilities authority to shut off electric power in order to protect public safety. This allows the energy companies (SDG&E, PG&E, SCE, Liberty, Bear Valley and PacifiCorp) to shut off power for the prevention of fires where strong winds, heat events, and related conditions are present.

In 2017, fires raged in Santa Rosa, Los Angeles, and Ventura making it one of the most devastating wildfire seasons in California's history. In response to the 2017 wildfires and Senate Bill (SB) 901, the Commission revised earlier guidelines on the de-energization of powerlines.

The CPUC adopted the most current set of PSPS guidelines on June 5, 2020.

In 2020, the electric companies' PSPS plans include provisions for COVID-19 measures. Click here for the utilities' 2020 Planning for Public Safety Power Shutoffs (PSPS).

Access to information about consumer disaster relief protections for customers of affected areas during any declared state of emergency, including wildfires, is available on this CPUC News Blog.

Evolution of Public Safety Power Shutoffs in California

The CPUC continues to take action to mitigate the impacts of PSPS events:

- On June 11, 2020, the CPUC adopted short-term Actions to Accelerate Microgrid Deployment and other resiliency solutions in Decision 20-06-017.
- On May 28, 2020, the Commission adopted updated and additional PSPS guidelines to mitigate wildfire risk and the impact on customers when a utility considers implementing a PSPS. These guidelines were approved in Decision 20-05-051, which contains Appendix A, which is Phase 2 of Rulemaking 18-12-005. The CPUC opened this rulemaking to examine de-energization of power lines (PSPS).
- On May 28, 2020, the CPUC enhances community engagement and collaboration for utility PSPS events. (Fact sheet here, updated October 2020.)

The current PSPS guidelines (D.20-05-051) direct the electric utilities to more actively and holistically take into account the needs and input of the Access and Functional Needs (AFN) community, including vulnerable populations and current and potentially eligible medical baseline customers.

Government Code 8593.3 defines "access and functional needs population" as individuals who have the following conditions: Developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking, older adults, children, people living in institutionalized settings, those who are low income, homeless, transportation disadvantaged, including those who are dependent on public transit, those who are pregnant. The CPUC and the Governor's Office of Emergency Services have adopted this definition as well.

Click here for a list of AFN actions the guidelines direct the electric utilities to take during a PSPS event.

Phase 2 guidelines are a recent CPUC action directing the electric companies before, during and after a PSPS event. These current guidelines ensure the IOUs enhance consistent, customer-friendly communications before and during PSPS events, minimize the impact on customers when energy utility companies implement PSPS events, and increase accountability with impacted regional Working Groups and reports.

The current Phase 2 guidelines are preceded by and build upon past CPUC actions, described below.

- On April 30, 2020, the CPUC Safety and Enforcement Division (SED) completed a Public Report on the Late 2019 Public Safety Power Shutoff Events (attachments: Part 1, Part 2) that assessed the performance of PG&E, SCE and SDG&E during the late Fall 2019 PSPS events. (SED served its Report in June 2020 to the I.19-11-013 service list, and the Report was incorporated into the record of R.18-12-005 in September 2020.)

  The late 2019 PSPS Events by the three utility companies caused customer confusion, anger, and resulted in some customers, including medical baseline customers, not being notified of the PSPS. These PSPS events spurred many CPUC actions.

  On Oct. 18, 2019, the CPUC held an Emergency Meeting to hear from top Pacific Gas and Electric Company (PG&E) executives to publicly address the mistakes and operational gaps identified in the utility's October 2019 PSPS events and to provide lessons learned to ensure they are not repeated.

  More information about the meeting and CPUC actions in response to all three companies' Late Fall 2019 PSPS Events is available on the "October 2019 PSPS Events" webpage.

- Phase 1 guidelines were approved on May 30, 2019, in a decision in the R.18-12-005 proceeding, to prepare for the 2019 fire season.
- The CPUC opened a new Rulemaking (R.18-12-005) on December 13, 2018 to examine the utilities' PSPS processes and practices in response to Senate Bill 901.
- Resolution ESRB-8 was adopted on July 12, 2018 to strengthen customer notification requirements before de-energization events and required utilities to submit a report within 10 days after each de-energization event.
- On April 19, 2012, the CPUC provided its first PSPS guidance to utilities in Decision 12-04-024, in response to SDG&E's Application 08-12-021 requesting specific authority to shut off power as a fire-prevention measure against severe Santa Ana winds and a review of SDG&E's proactive de-energization measures.

Utility Company PSPS Post Event Reports

The reports in this section are submitted by the utility companies in accordance with Resolution ESRB-8, Ordering Paragraph 1 of California Public Utilities Commission (CPUC) Decision (D.) 19-05-042 (Phase 1), and Ordering Paragraph 1 of Decision (D.) 20-05-051 (Phase 2).

Reports are listed by the date of the PSPS event or anticipated PSPS event, not the date the report was submitted.

- **CPUC PSPS Rollup: Oct. 2013 Through Dec. 31, 2020**

2021 Utility Company PSPS Post Event Reports

PG&E

- Jan. 19, 2021: PSPS Post Event Report

SCE

- Apr. 12-13, 2021: PSPS Post Event Report
- Jan. 12-21, 2021: PSPS Post Event Report
  - Amended Jan. 12-21, 2021: PSPS Post Event Report

SDG&E

- Jan. 14-16, 2021: PSPS Post Event Report

2020 Utility Company PSPS Post Event Reports

2019 Utility Company PSPS Post Event Reports

2018 Utility Company PSPS Post Event Reports

2017 Utility Company PSPS Post Event Reports

Potential Impacts on Telephone Service during De-Energization

End users of communication services will receive differing levels of service when their provider loses power. Communications service providers are required under Decision 10-01-026 to implement programs to educate their customers on the different types of back up power supplies and how to obtain them.

Will my telephone work in a de-energization event? It depends.

- Wireline customers who subscribe to POTS (plain old telephone service) voice service using copper lines generally have service during a power outage. This is because the central office that serves the residence as backup power, which provides the electricity necessary to operate a wired telephone during a power outage.
  - The CPUC does not have rules mandating backup power for this service, however most central offices do have and maintain backup power.
  - Cordless phones require the end user to maintain the batteries in those devices, so that the home portion of the telephone service can operate in a power outage.

- For VoIP customers, service during a power outage depends on the underlying facility used by the provider. Some VoIP providers will maintain line power (some variants of DSL) during an outage, and others rely on network power which may or may not be present.
- Cable subscribers with voice service may or may not have service in a power outage.
  - The CPUC does not have rules mandating backup power for this type of service.

- Wireless (cellular) customers may or may not have voice service in a power outage, depending on the backup power installed at cell sites.
  - The CPUC does not have rules mandating backup power for this type of service.

- It is the responsibility of the customer to obtain the required backup power in the residence to have working telephone service during an outage event. This might include batteries for cordless phones, routers, WIFI, fiber termination devices, and other customer premises equipment.

Does a communication provider have to provide service? Some do.

- A service provider that is designed a Carrier of Last Resort (COLR) must offer basic service to all residential customers in its territory under Decision 12-12-038. This includes AT&T, Consolidated, Frontier, and 13 small rural carriers. View a list of all the COLRs and a map of their service territories.
  - One required element of basic service is for COLRs to provide free access to 9-1-1.
  - The CPUC does not have rules for service providers to keep telephone service operational during a planned power outage.

- If you have a complaint about your telephone service, first call your service provider. If they don't fix it, then please call the CPUC's Consumer Affairs Branch at (800) 649-7570 to submit an informal complaint.

The CPUC's General Order 168 Rule 3 requires communication providers who offer end-user access to the public switched telephone network to provide access to 9-1-1 emergency services to all residential customers and wireless devices. Rule 3 does not require carriers to provide access to 9-1-1 during a power outage or de-energization event.

CPUC Resolution ESRB-8 requires electric utilities to make all practical attempts to notify and coordinate with all potentially affected communications service providers before and after a de-energization event.

- Jul. 16, 2020: CPUC Requires Wireless Companies to Better Serve Customers in Emergencies (CPUC Press Release)

More Information

For additional information, including utility company Progress Reports, go to the company website.

Contact

Contact the CPUC's Public Advisor's Office at public.advisor@cpuc.ca.gov or U.S. mail at CPUC, Public Advisor's Office, 505 Van Ness Ave., San Francisco, CA 94102 if you have questions or would like to comment.

Looking for Consumer Information?

Information on our programs, complaint process, brochures, and more!

Visit the Consumer Information Website

Meetings on PSPS Issues

Please visit our events calendar for upcoming meetings.

- Apr. 20, 2021: CPUC Tree Overstrike Workshop on PG&E’s Proposed Implementation of Proposed Probation Conditions in its PSPS Program
  - Media Advisory
  - Agenda
  - Presentation
- Mar. 29, 2021: Joint IOU 2020 PSPS Workshop
  - Media Advisory
  - Agenda
  - PacifiCorp Presentation
  - PG&E Presentation
  - SDG&E Presentation
- Mar. 26, 2021: Meeting on Wildfire Risk Analysis Results
  - Media Advisory
  - Agenda
  - Technosylva Presentation
- Mar. 1, 2021: SCE 2020 PSPS Corrective Action Plan Meeting
  - Media Advisory
  - Agenda
  - SCE Presentation
  - Webcast Recording
- Jan. 26, 2021: SCE Meeting on Execution of 2020 PSPS Events
  - Media Advisory
  - SCE Presentation
  - Agenda
  - Webcast Recording
  - Jan. 19, 2021: Public Meeting
  - Jan. 19, 2021: President Batjer's Letter to SCE
  - Jan. 22, 2021: SCE's Reply Letter
  - Feb. 12, 2021: SCE's Correction Action Plan
- Aug. 13, 2020: PG&E PSPS Public Briefing
- Aug. 11, 2020: SCE PSPS Public Briefing
- Aug. 10, 2020: SDG&E PSPS Public Briefing

PSPS News & Updates

- Jun. 28, 2021: CPUC Executive Director letter to PG&E on Tree Overstrike
- Jun. 24, 2021: CPUC Issues Additional Guidelines and Rules in Continual Improvements to Utility Execution of Public Safety Power Shutoffs
- Feb. 12, 2021: SCE's Correction Action Plan
- Feb. 19, 2021: CPUC Proposes Additional Guidelines for Utilities To Minimize the Impact of Public Safety Power Shutoffs
- Jan. 22, 2021: SCE Reply Letter to President Batjer
- Jan. 19, 2021: CPUC To Hold Meeting on Jan. 26 To Hear From SCE About Execution of Recent PSPS Events
- Jan. 19, 2021: CPUC President Marybel Batjer letter to SCE re: 2020 PSPS Events
- Jan. 14, 2021: CPUC Adopts Strategies To Help Facilitate Commercialization of Microgrids Statewide
- Sept. 8, 2020: PG&E Response Letter Appendix - Community Resource Centers and Supplemental Information

- Sept. 8, 2020: PG&E Response Letter
- Sept. 8, 2020: SCE Response Letter
- Sept. 8, 2020: SDG&E Response Letter
- Aug. 27, 2020: President Batjer Follow-Up Letter to PG&E, SCE, and SDG&E on Utility PSPS Public Briefings
- Apr. 30, 2020: SED served a copy of its Public Report on the Late 2019 PSPS Events to the service list of I.19-11-013
- Nov. 1, 2019: Consumer Protections and Resources for Wildfire Victims

Utility Company PSPS Programs

As a result of Resolution ESRB-8, the electric utilities developed de-energization programs, referred to as "Public Safety Power Shutoff" (PSPS) as a preventative measure of last resort if the utility reasonably believes that there is an imminent and significant risk that strong winds may topple power lines or cause major vegetation-related issues leading to increased risk of fire. The programs outline criteria the utility analyzes when considering shutting off power to one of more electric distribution or transmission lines, and protocols for when and how customers are notified. Information about the utilities' PSPS programs can be found in the links below.

Under each utility PSPS program link below, click to read the utility's Progress Report describing its implementation of the PSPS Guidelines that were adopted in Decision (D.) 19-05-042, Appendix A.

Pacific Gas and Electric Company (PG&E)

- PG&E PSPS Programs

Southern California Edison (SCE)

- SCE PSPS Programs

San Diego Gas & Electric (SDG&E)

- SDG&E PSPS Programs

PacifiCorp

- PacifiCorp PSPS Programs

Liberty Utilities (CalPeco Electric) (Liberty)

- Liberty PSPS Programs

Bear Valley Electric Service (BVES)

- BVES PSPS Programs

PSPS Resources

- The Power of Being Prepared
- State of California Wildfire Response Resources
- CAL FIRE - Ready for Wildfire
- Cal OES - Governor's Office of Emergency Services
- Info on the Self-Generation Incentive Program
- PSPS Frequently Asked Questions

Pacific Gas and Electric Company®

Meredith E. Allen
Senior Director
Regulatory Relations

77 Beale Street, Room 2341
San Francisco, CA 94105

Mailing Address
Pacific Gas and Electric Company
P.O. Box 770000
Mail Code: B23A
San Francisco, CA 94177

Tel.: 415-973-2868
Meredith.Allen@pge.com

November 8, 2019

Elizaveta Malashenko
Deputy Executive Director, Safety and Enforcement
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA, 94102

Dear Ms. Malashenko:

On October 25, 2019, PG&E submitted its compliance report for the proactive de-energization event that was initiated on October 9, 2019 and fully restored on October 12, 2019. PG&E submitted this report as required by Resolution ESRB-8 and in accordance with Ordering Paragraph 1 of California Public Utilities Commission (Commission) Decision (D.) 19-05-042.

Today, PG&E is submitting an amendment to that report. PG&E's amendment updates the incidents of damage found, the list of circuits that were de-energized, and number of impacted customers. Updates are provided in redline. This report has been verified by a PG&E officer in accordance with Rule 1.11 of the Commission's Rules of Practice and Procedure.

If you have any questions, please do not hesitate to call.

Sincerely,

Meredith E. Allen

Meredith E. Allen
Senior Director – Regulatory Relations

Enclosures

cc: Leslie Palmer, SED
Anthony Noll, SED
Charlotte TerKeurst, SED
Dan Bout, SED
ESRB_ComplianceFilings@cpuc.ca.gov
EnergyDivisionCentralFiles@cpuc.ca.gov

AMENDED PG&E Public Safety Power Shutoff (PSPS) Report to the CPUC October 9-12, 2019 De-Energization Event

Executive Summary

The devastating wildfires of the past two years have made it overwhelmingly clear that more must be done, and with greater urgency, to adapt to and address the growing threat of wildfires and extreme weather facing our state.

As gusty winds and dry conditions increase the risk of damage to the electric infrastructure and the potential for rapid fire spread, it will be necessary for Pacific Gas and Electric Company (PG&E or the Company) to turn off electricity in certain areas in the interest of public safety.

PG&E knows how much our customers rely on electric service, and the impacts that these shutoff events can have on them, their families, businesses and communities. PG&E considers temporarily turning off power, based on weather and fire-risk conditions, only in the interest of safety to reduce the risk of wildfire.

On Sunday, October 6, 2019 at 1800, PG&E activated its Emergency Operations Center (EOC) in anticipation of a PSPS event impacting multiple Fire Index Areas (FIA). This particular Public Safety Power Shutoff (PSPS) event became the largest to date, impacting ~~728,980~~ 732,348 customers in 35 counties across the Sacramento Valley, Sierra Foothills, North Bay, South Bay, East Bay, Central Coast, and parts of Southern California.

Between October 6 and October 12, 2019, PG&E responded to a forecasted offshore wind weather event by proactively turning off power in multiple phases, in an effort to reduce the risk of wildfire ignition.

As PG&E prepared to take these steps for public safety, it followed established protocols and communicated to customers directly, providing advanced notification when and where possible via automated calls, texts, e-mails and online notices. Medical baseline customers also received repeat automated calls and texts at hourly intervals until they confirmed receipt of notifications. PG&E knocked on the doors of medical baseline customers who did not confirm receipt of these notifications and were not otherwise reached. PG&E representatives who visited medical baseline customers also left a door hanger with information if the customers were not home at the time of visit.

Throughout the PSPS event, PG&E communicated continuously with state and local officials and proactively engaged the media via news briefings, news releases, interviews and social media updates. This included sharing information in the various required languages.

The decision to de-energize was made by a designated Officer-in-Charge (OIC) at PG&E's EOC, which was staffed by PG&E's electric operations, meteorology, customer care, public information and government liaison functions, as well as other functions.

The first phase of shutoffs impacted customers shortly after midnight on October 9 in portions of the following counties: Amador, Butte, Calaveras, Colusa, Contra Costa, El Dorado, Glenn, Humboldt, Lake, Marin, Mendocino, Napa, Nevada, Placer, Plumas, Shasta, Sierra, Siskiyou Solano, Sonoma, Tehama, Trinity, Yolo, and Yuba counties.

The second and third phases of the PSPS event began later the same day, Wednesday, October 9, at approximately 1400 and 2200, respectively impacting portions of the following counties: Alameda, Alpine, Calaveras, Contra Costa, Mariposa, Mendocino, Merced, San Joaquin, San Mateo, Santa Clara, Santa Cruz, Stanislaus, and Tuolumne.

The last phase was executed at approximately 0945 on Thursday, October 10, for portions of Kern County.

Key Learnings

PG&E appreciates the feedback we have received from the Governor's office, state agencies, our customers and our communities since the last PSPS event. PG&E has taken those requests and suggestions seriously and is working to implement many of them for this and future PSPS events. While PG&E recognizes that the scope of the October 9 event is unsustainable in the long term, it was the right decision given the large-scale weather event and the damage to PG&E's electric system that unfolded across our service area. PG&E appreciates the offer of ongoing assistance from state agencies and will continue to work closely with the representatives from the California Department of Forestry and Fire Protection (CAL FIRE), The Governor of California's Office of Emergency Services (Cal OES) and the California Public Utilities Commission (CPUC or Commission) that were embedded in our EOC during this event operational period.

PG&E acknowledges falling short in several areas of execution, which is why PG&E is committed to closing identified gaps quickly. First and foremost, PG&E has reinforced its website and redistributed staffing in its call centers to handle a much higher volume for future events.

In the short term, and for immediate future events, all customers visiting pge.com or its sub-pages will be redirected to a temporary website where critical information such as PSPS address lookup, Community Resource Center (CRC) locations, and other PSPS event-related information will be available. The redirect will occur just before PSPS notifications are sent to customers at approximately the 48-hour mark prior to de-energization.

PG&E wants to ensure that critical information is available to customers at all times. This special event website has been tested to handle high volume and PG&E does not expect significant interruption to website accessibility during an event, while we execute on a more permanent solution for pge.com. Many online services, including the ability to pay energy bills, will be unavailable while we are redirecting traffic from pge.com to pgealerts.com.

Additionally, and for immediate future PSPS events, PG&E call centers will be focused on taking emergency and PSPS calls only.

PG&E also understands that our CRCs did not adequately meet the needs of the customers who used them for this very large event. For future events, we have begun to acquire spaces that are accessible to Access and Functional Needs (AFN) populations, and will extend the hours of operation by two hours, to be 8 a.m. to 8 p.m. PG&E will partner with local agencies to identify where CRCs should be located, to open as many CRCs across the impacted service area as possible and to post locations and hours on pge.com.

Finally, we are working to strengthen coordination with government agencies, in particular the counties, cities, and tribal governments in our service area. Effective immediately, we have established a single point of contact for each county. We have created a dedicated agency helpline monitored 24/7 for special requests from our counties and tribes. In addition, we are offering each county a remote or onsite Geographic Information System (GIS) mapping specialist to provide more real-time information and technical support.

Section 1 – Explanation of PG&E's Decision to De-Energize

October 4: While preparing to execute the October 5-6 PSPS event, PG&E began monitoring a potentially stronger offshore wind event near mid-week the following week around October 9 or 10.

- The Predictive Services unit of the Northern California Geographic Area Coordination Center (North Ops) 7-Day forecast indicated "*Confidence increasing for a potentially stronger N-NE-offshore wind event Wed-Thur as high pressure re-builds and could warrant a High Risk in the coming days*."
- Global weather models available such as the Global Forecast System (GFS) and the European Centre for Medium Range Weather Forecasting (ECMWF) model, and respective model ensembles, indicated a dry offshore or "Diablo" and "Santa Ana" wind event. The operational run of the 10/4/2019 0000 Coordinated Universal Time (UTC) ECMWF model indicated peak Redding airport (KRDD) to Sacramento Airport (KSAC) pressure gradients near 6 millibars (mb), and San Francisco airport (KSFO) to Winnemucca airport in Nevada (KWMC) pressure gradients near -18 mb. In short, the ECMWF model was forecasting the strongest offshore wind event of the season thus far.
- PG&E's Dynamic Pattern and Analog Matcher[1] (DPAM) showed that the best analog match to the upcoming forecast was October 8-9, 2017 when several catastrophic wildfires had occurred within PG&E's territory.

PG&E Meteorology issued the publicly available 7-Day PSPS Potential forecast which was published to www.pge.com/weather and indicated multiple zones in an elevated state for Wednesday into Thursday, October 10. PG&E Meteorology continued to

---

[1] PG&E's DPAM is an internally-developed forecasting tool that automatically matches GFS forecasts for the next 7 days against the North American Regional Reanalysis (NARR) from January 1995 through July 2019 using seven atmospheric fields: 500- and 700- hectopascal (hPa) geopotential height, 250- and 500-hPa winds, 700-hPa temperature, precipitable water, and sea-level pressure. DPAM returns the top 20 historical analogs that can be studied in more detail by a PG&E meteorologist.

update the 7-Day PSPS Potential forecast accordingly leading up to and throughout the event.

October 5: PG&E meteorology participated in an interagency conference call hosted by North Ops that was also attended by local National Weather Service (NWS) offices. There was consensus amongst meteorologists that a strong offshore wind event was still being forecast for the 9th and 10th by global forecast models.

- North Ops 7-Day forecast elevated to "High Risk" indicating a Critical Burn Environment that, given an ignition, significant fire growth will occur due to a combination of sufficiently dry fuels and critical weather conditions.[2]
- The 10/5/2019 1200 UTC ECMWF operational weather model forecasted peak pressure gradients to be among the strongest in the PG&E pressure gradient archive, which dates back to January 1, 1995. It was also noted that if these pressure gradients developed as forecasted, this would be the strongest event observed since October 2017.
- An in-depth analysis of historical events by PG&E Meteorology using the DPAM tool indicated the weather on October 8 and 9, 2017 as the most similar match to the upcoming event.

Based on information from the global forecast models, PG&E Meteorology produced an initial draft scope, a GIS polygon, of the potentially impacted areas where gusty winds may produce risk of outage activity. Typically, the 'event scope' is produced closer to the event once output from the PG&E high resolution model becomes available; however, there was need to estimate the scope based on the coarser global models earlier due to the potential seriousness and magnitude of the event. As the October 8-9, 2017 event appeared to be an appropriate analog, meteorological and fire potential data from that event was also utilized to help create the draft scope.

During the analysis, two distinct risk periods were identified. The first associated with north winds down the Sacramento Valley and adjacent terrain including the North Bay and Sierra foothills starting on the morning of October 9. Forecasts of peak wind gusts were estimated to be near 50 miles per hour (mph) with widespread gusts 35-45 mph. The second period of risk was expected to occur overnight and associated with strong and downslope northeast winds. That period was identified to begin around sunset on October 9. Forecasts of peak wind gusts over the highest peak and wind prone spots were estimated to reach 60-65 mph with widespread gusts of 40-55 mph elsewhere. The third period of wind risk associated with Santa Ana winds in the Tehachapis was yet to be identified.

October 6: Forecasts continued to show a strong, outlier, high-risk event. Based on consensus amongst forecast models, low dispersion in the forecast model ensembles, and consensus among the experts, confidence continued to grow around this event producing considerable and dangerous fire weather and fire potential.

---

[2] https://www.predictiveservices.nifc.gov/outlooks/7-Day_Product_Description.pdf.

- NWS offices in Northern California began to issue Fire Weather Watches for the upcoming event. Both the Sacramento and Bay Area NWS offices issued Fire Weather Watches from Wednesday through Thursday for the upcoming high-risk fire weather event, noting in text discussions "*Given the degree of model consistency and agreement, forecast confidence is high*."
- ECMWF pressure gradients from the 10/6/2019 0000 UTC forecast continued to indicate a strong, outlier event. Many ensemble forecast members indicated potential of an even stronger event than the operational version.
- National Oceanic and Atmospheric Administration (NOAA) Storm Prediction Center (SPC) discussed the coming threat and highlighted critical fire danger in products and forecast discussions.

Through the course of the day, PG&E's high-resolution weather model (PG&E Operational Mesoscale Modeling System (POMMS)) started to resolve the event, allowing more detailed analysis. The high-resolution model is run out 84 hours, such that by 1500 on 10/6/2019 forecast data was available through 11 p.m. on 10/9/2019. The POMMS model was also run historically each hour over the past 30 years so that historical wind speeds can be analyzed and visualized, and to put the forecast in perspective historically. On 10/9/2019, the forecasted wind speed at many locations were >99 percent historical values.

As the scope of the event appeared large and widespread, at the request of Cal OES, PG&E held an interagency call and video conference at 1800 hours and invited NWS offices from central and Northern California, as well as North Ops. The purpose of the call was to share PG&E's analyses with agencies, PG&E's thoughts about the forecast and potential scope and hear points and thoughts from other experts. PG&E made it clear it was open to challenges in its analysis and welcomed any points counter to the risks PG&E discussed. Representatives from North Ops, NWS Sacramento, Bay Area and Eureka participated on the call and each meteorological entity confirmed what PG&E was seeing: a high-risk event with potential for significant fires. There was consensus this was looking like the highest risk event of the season; likely the strongest since October 2017. Notes from the call were sent to the Cal OES representative embedded in the EOC, who verbally confirmed receipt and that they passed the notes to Cal OES leadership.

Based on the factors above, PG&E made the decision to activate the EOC at 1800 on 10/6/2019, shortly after closing it from the October 5-6 event, to prepare for the coming weather event.

Near 2200 on 10/6/2019, PG&E meteorology obtained Utility Fire Potential Index (FPI) model output that had data available through 0000 10/10/2019 and Outage Producing Wind (OPW) data available through 0500 on 10/10/2019. Based on this data, meteorology refined the meteorological footprint of the first two risk periods identified and monitored a potential third period of risk in a portion of Kern county where Santa Ana winds were expected to develop.

Meteorology also updated their wind forecasts were as follows:

- North Bay – Peak gusts 60-70 mph, with widespread gusts 40-55 mph;
- Sierra Nevada – Peak gusts 60-70 mph, with widespread gusts 40-55 mph;
- East Bay – Peak gusts 45-50 mph, with widespread gusts 30 - 40 mph; and
- South Bay & Santa Cruz Mountains – Peak gusts 50-55 mph, with widespread gusts 35-45 mph.

October 7: Overnight, the latest weather models available were analyzed and showed no significant changes in the strength of the event.

- PG&E meteorology continued to study the upper level and surface forecasted pattern, which was a synoptic setup for a Diablo wind event that brings cold dense air into the Pacific Northwest and the upper great Basin, producing strong offshore pressure gradients and dry, offshore winds.
- North Ops noted in their forecast noted "*unusually strong N-NE Winds/Low RH*" and that there is ""*High confidence for a +97th percentile High Risk atmospheric event*."
- Fuels were reported to be sufficiently dry to carry and support significant fires and it was mentioned the fuel loading of fine fuels, which have now cured, was above normal due to four consecutive years of above normal grass growth.
- The Sacramento NWS office issued a fire weather watch across a vast portion of Northern Ca and noted "*easier fire starts*", "*Potential for the rapid spread of fire*" and winds gusts up to 45 mph, locally higher. Sacramento NWS also issued a wind advisory for the Sacramento Valley adjacent elevated terrain including the Sierra foothills and Lake county for potentially damaging winds due to strong wind gusts.

Through the day, PG&E's FPI and OPW models remained consistent in showing vast portions of the elevated terrain of the Bay Area, north coastal mountains and Sierra with elevated fire potential combined with potential for outage activity.

At 1645, the OIC gave the authority to execute customer notifications and external communication for the footprint Meteorology previously identified for the first two periods of risk. (These two risk periods were eventually referred to as Phases 1, 2, and 3.)

Near 2200 on 10/7/2019, PG&E meteorology obtained FPI model output that had data available through 0000 10/11/2019 and OPW data available through 0500 on 10/11/2019. Based on this data, meteorology refined the meteorological footprint of the event for the first two periods of risk and developed a footprint for a portion of Kern County where Santa Ana winds were expected to develop.

Peak gusts were communicated as follows:

- North Bay – Peak gusts 60-70 mph, with widespread gusts 40-55 mph;
- Sierra Nevada – Peak gusts 60-70 mph, with widespread gusts 40-55 mph;
- East Bay – Peak gusts 45-50 mph, with widespread gusts 30-40 mph; and

- South Bay & Santa Cruz Mountains – Peak gusts 50-55 mph, with widespread gusts 35-45 mph.

October 8: Model forecasts continued to remain consistent with the upcoming strong wind event and showed no significant changes from previous forecast model solutions.

- The NWS Bay Area office upgraded fire weather watches to Red Flag Warnings (RFW) noting "*This event has the potential to be the strongest offshore wind event in the area since the October 2017 North Bay Fires*." They also issued a wind advisory for the North and East Bay Hills above 1000 feet and noted "*critical fire weather conditions. Possible downed trees and powerlines*."
- The NWS Sacramento and Eureka offices also upgraded fire weather watches to RFWs.
- The Storm Prediction Center forecast also showed elevated to critical fire weather for vast portions of PG&E's territory that also encompassed the meteorological footprint PG&E Meteorology identified for the event.
- PG&E's Storm Outage Prediction Project (SOPP) model also predicted considerable outage activity on the 9th and 10^{th}.

At 0800, the OIC gave the authority to execute customer notifications and external communication for the meteorological footprint in Kern County. (This risk period was eventually referred to as Phase 4.) The OIC also approved the decision to de-energize the first two periods of risk. This included an expansion of the meteorological scope approved for de-energization based on new areas of high risk identified the latest POMMS model run. The de-energization scope was approved to expand the previously identified footprints in the East Bay, Santa Cruz, and Marin.

October 9: Forecasts from the NWS and North Ops showed little change; the event was beginning to unfold with gusty northerly winds developing down the Sacramento Valley.

- All forecast entities (PG&E, NWS, North Ops, South Ops, SPC) were aligned that this event looked like the strongest offshore wind and highest fire risk event of the season and likely strongest since October 2017.
- RFWs and "high-risk" forecasts remained in effect from the NWS and North Ops, respectively with 44 of 58 California counties at least partially covered by a RFW in this event with 37 of those counties in the PG&E territory.
- The POMMS FPI model continued to suggest high potential of significant fires across vast portions of Northern California and PG&E's OPW model also suggest high risk of outages if lines remained energized.

Near 1200 on 10/9/2019, PG&E meteorology refined the meteorological footprint of the Kern County event using the latest FPI, OPW and agency data available. At 1300 on 10/9/2019 an OIC decision meeting to de-energize was convened for the Kern county location. Wind gusts were communicated as widespread gusts 25-35 mph with peak gusts of 55 mph.

At 1455 the OIC approved the final scope and de-energization for the Kern county footprint.

When analyzing the timing of the second phase of the Northern California weather event, the meteorology data indicated that the wind event would start at later than expected for the customers in the Santa Cruz and the East Bay. Based off this information, the OIC requested that the de-energization start time be delayed from 1700 to 2200 of 10/9 to further mitigate any customer impacts.

By the evening, the northerly component of the event was winding down, but a very dry airmass had settled over Northern California with copious humidity observations in the teens to single digits. At 1800 the weather station on the top of Mount St. Helena recorded wind speeds of 30 mph with gusts to 41 mph along with RH at 7 percent.

<u>October 10</u>: The strongest winds were recorded at 0400 and 0410 on the 10th where sustained winds of 68 mph were observed with gusts to 77 mph. Later that morning a review of public forecasts indicated no major changes.

- RFWs were still in effect across vast portions of California (44 counties), North Ops still forecast several PSAs as high-risk (35 counties in the PG&E territory).
- NOAA SPC forecasted elevated, critical and extreme fire weather across vast portions of California with 32,301 sq. miles of California under critical fire weather, which encompassed a population of 9.2 million Californians.

Through the course of the day, PG&E meteorology monitored wind speeds, pressure gradients and forecast models in order to recommend an "all-clear" so that crews could begin to inspect lines for energizing. Forecast models suggested winds would continue to taper off for almost all areas of Northern California except for the northern Sierra where another round of offshore winds was expected in the evening. Based on winds, pressure gradients and forecast models, the 'all-clear' was approved by the OIC for the Santa Cruz mountains, East Bay, Marin county, and areas south of I-80. Near 1400, based on the same criteria, the all-clear was given by the OIC for the remainder of the Northern California scope.

In Southern California, the Hanford NWS office continued a RFW for Kern County and south-eastern Tulare County mountain, which was in effect from 10 a.m. on the 10th through 5 p.m. on the 11th. In the RFW they noted that wildfires could spread quickly and change direction. At 2:13 p.m. on the 10th the Remote Automated Weather Station, Grapevine Peak, recorded wind gusts to 51 mph with RH at 6 percent.

<u>October 11</u>: At 2:13 p.m. on the 10th the Remote Automated Weather Station, Grapevine Peak, recorded wind gusts to 51 mph with RH at 6 percent. PG&E meteorology continued monitoring wind speeds, pressure gradients and forecast models in order to recommend an "all-clear" so that crews could begin to inspect lines to re-energize. Near 0800, winds had sufficiently decreased and the all-clear was given for the northern Sierra. The RFW in the area would expire at 1000 on the 11th. In the Kern county footprint of the PSPS event, the all-clear was determined near 1500 on the 11th, 2 hours before the RFW would expire. At this point in time, all areas impacted by the PSPS event had been given the all-clear.

Section 2 – Factors Considered in Decision

No single factor dictates the decision to de-energize. PG&E carefully reviews a combination of factors when determining if power should be turned off for public safety. The factors described below were considered in reaching the decision to de-energize on October 9-10:

Weather: FPI and OPW forecasts; forecast model trends and run to run consistencies; the latest forecasted pressure gradients; timing of the event; hourly wind forecasts; the updated meteorological event footprint; relative humidity forecasts; a review of external agency forecasts; fire weather watches and RFWs issued by NWS forecast offices; Wind advisories issued by the NWS; North Ops Predictive Services "high risk" forecasts for several PSAs. (See detailed description in Section 1 and Section 16 for additional meteorological data including max windspeeds by county.)

- Field Data: Real-time data from PG&E's weather station network and PG&E's Wildfire Safety Operations Center (WSOC) reported hourly in the hours approaching de-energization. There were no exceptions on active fires or field observations reported by WSOC impacting the decision to de-energize. Weather stations and field observers using handheld Kestrel wind meters were used to confirm wind speeds against the forecast.
- Transmission Line Scope: Enhanced inspections completed on all transmission facilities within the potential PSPS scope as a part of the Wildfire Safety Inspection Program (WSIP). Insights from enhanced inspections and other asset health data informed assessment of each transmission line's wildfire risk, which includes historical outages, open maintenance tags, date of the last vegetation patrol, and vegetation Lidar data. Assessment results confirm asset health and low wildfire risk for the majority of transmission lines within the potential PSPS scope, resulting in the ability to safely maintain power on these lines and to reduce customer impacts.
- Power Flow Analysis: Completion of power flow analysis for transmission facilities within the PSPS scope, which analyzes potential downstream impacts of load shedding, coordinates with CAISO, and confirms solution feasibility with Transmission System Protection. Results from this analysis confirmed the ability to maintain grid integrity during the potential event, and identified the following notable customer impact.

- Customer Impact: Number of customers impacted by the potential de-energization estimated at the time the decision was made was approximately 752,000[3] customers. Of those customers, approximately 4,500 were critical customers and approximately 30,800 were medical baseline customers. This impact was considered in conjunction with efforts to mitigate the impacts of de-energization.
- Alternatives to De-Energization: Inadequacy of alternatives to de-energization, including the below steps taken leading up to the potential PSPS event:
  - Additional vegetation management deployed to address active open tags (i.e., vegetation recently inspected but not yet cleared) within the potential PSPS scope; Work complete on a portion of this population; the remaining will be ongoing.
  - Pre-patrol of transmission lines within the potential PSPS scope using helicopters.
  - All automatic reclosing disabled in Tier 2/Tier 3.
  - Sectionalizing implemented to the extent possible, reducing the potential PSPS impact by approximately 77,000 customers.
- Mitigations to the Impacts of De-Energization: Updates on the below ongoing mitigation efforts to lessen the impact on public safety and customers:
  - Confirmation of notifications sent to customers potentially impacted by the PSPS scope, including critical facilities and medical baseline customers.
  - Confirmation of 29 CRCs planned to serve 29 counties, with 9 of the 29 still pending specific site location (29 represents CRCs known at the time of the decision. On-going efforts resulted in a total of 33 CRCs ultimately stood up for this event.).
  - Confirmation that resource personnel (ultimately over 6,000) was on track with the objective of deploying on the morning of October 9 for training, followed by pre-staging in the field two hours prior to weather clearing for patrol start
  - Confirmation of 24 Safety and Infrastructure Protection Team (SIPT) crews prepared to conduct observations and support pre-treatment, switching, and location jurisdictions where needed throughout the event.

---

[3] Actual count of customers de-energized may vary from planned customers impacted due to system conditions encountered during actual de-energization including circuit configuration and differences between actual and as-modeled alignment. Customer totals prior to de-energization include inactive customer accounts; after de-energization, actual customer outage totals do not include inactive customer accounts. Reconciliation results in an updated customer impact total; total customer impact after post-event reconciliation and as reported throughout this report is approximately ~~729,000~~ 732,000 customers.

Section 3 – Time, Place, and Duration

Appendix B shows each circuit involved in the PSPS event, along with the following for each circuit: whether the areas affected by the de-energization are classified as Zone 1, Tier 2, or Tier 3, as per the definition in General Order (GO) 95, Rule 21.2-D; the start time of the outage; communities served; and the restoration data and time for the last customer re-energized. Restoration of the circuits takes place in sections. The restoration time represents the date and time when the last section of the circuit and associated customers were restored.

The event began on October 9, 2019 at 0009 when the first circuit was de-energized. The event ended on October 12, 2019 at 1741 when the last circuit was restored. The de-energization occurred in the communities listed in the Appendix B. PG&E attempted to minimize the duration and location of de-energization by phase de-energization of circuits to align with the timing of weather arriving in different regions.

Section 4 – Customers Impacted

Please see Appendix C for each distribution and transmission circuit involved, the total number of customers impacted on each circuit, and the number of customers impacted on each circuit by type.

Approximately ~~729,000~~ 732,000 distribution customers and 35 transmission customers were de-energized during this event.

The approximate distribution customers by type are as follows:

- ~~636,000~~ 639,000 residential;
- ~~81,000~~ 82,000 commercial/industrial;
- 11,300 other; and
- Of the approximate total ~~729,000~~ 732,000 customers, approximately 30,000 are medical baseline.

The 35 transmission customers were all commercial/industrial. See Appendix C for customers by type per circuit de-energized.

Table 1 – Summary of De-energization Start and Restoration by Phase

Phase	De-Energization Start Time	Restoration Completed
1	10/09/2019 0009	10/12/19 1741
2	10/09/2019 1351	10/12/19 1020
3	10/09/2019 2233	10/12/19 1225
4	10/10/2019 0947	10/12/19 525

Section 5 – Damage to Overhead Facilities

PG&E personnel patrolled all sections of de-energized PSPS circuits for safety prior to re-energizing. During those patrols, PG&E discovered ~~120~~ 116 instances of wind-related issues across impacted divisions that required remediation prior to re-energizing. These included ~~69~~ 65 instances of damage to PG&E assets such as conductors, service drops, and poles. In each case, PG&E repaired or replaced the damaged equipment prior to re-energizing. In addition to these damaged assets, PG&E personnel discovered 51 instances of documented hazards, all vegetation-related, such as branches found lying across conductors, which were cleared prior to re-energizing.

- ~~69~~ 65 cases of damages:
  - ~~26~~ 25 where vegetation was identified as the cause
  - ~~43~~ 40 cases of wind-caused asset damage or where the cause could not be identified
- 51 cases of hazards

See Appendix D for example photographs of damage and hazards.

Section 6 – Customer Notifications

Through direct notifications, PG&E proactively reached out to potentially impacted customers via automated calls, text messaging, e-mail, and personal phone calls, while also maintaining a strong media presence with customers. PG&E took additional steps to notify customers enrolled in PG&E's medical baseline program, who rely on electric service for mobility or life sustaining medical reasons, to ensure they confirmed receipt of the notification to adequately prepare for an outage. Customer notification details, including media engagement and digital updates, are further described below.

Media Engagement

Between Sunday, October 6 and Saturday, October 12, PG&E engaged with customers and the public through the media in the following ways:

- Provided information to a total of to 613 news organizations on a regular and ongoing basis. A total of 856 unique stories were issued by the media in online or print outlets;
- Issued at least two news releases a day with updates at key times during the event, for a total of 12 news releases;[4]
- Conducted five daily 6 p.m. media briefings with senior officers and members of PG&E's Meteorological team;

[4] https://www.pge.com/en/about/newsroom/newsreleases/index.page.

- Maintained a regular and ongoing social media presence on multiple platforms, including the use of Nextdoor Urgent Messages for the first time. PG&E issued 650+ social media posts, which were shared more than 12,300 times;
- Maintained both corporate and local Twitter handles to be able to more precisely target information to customers and stakeholders;
- Livestreamed the 6 p.m. daily media briefings on both Twitter and Facebook for the first time. See links to these briefings in Appendix E;
- Augmented paid advertising by increasing media buy on television and digital outlets for targeted ad messaging altering the public about the PSPS; and
- Created a radio spot targeting medical baseline customers who were not answering the phone, text or e-mails about the PSPS notifications.

PG&E Website

Up to and during this PSPS event, PG&E worked to actively provide event updates on www.pge.com, and implemented tools to drive traffic to the PSPS event updates page at www.pge.com/pspsupdates. This site included a tool for customers, public safety partners and interested parties to view polygons of the potential PSPS impact areas on a map, provided an address lookup tool for customers to determine if their home or business may be included in the scope of the active PSPS event, listed locations of the CRCs stood up by PG&E to support customers during the event, and allowed government agencies to download GIS maps of impacted regions. Additionally, on Monday October 7, in preparation for increased website traffic due to the scale of the planned PSPS event, PG&E doubled the database capacity for the site.

From the time PG&E's EOC was activated on Sunday October 6 to the time the last customers were restored on Saturday October 12, the PG&E website experienced an unprecedented amount of user traffic and "bot"[5] traffic when available. Over 1.7 million unique visitors went to the English version[6] of the PSPS event updates page, almost 10 times the normal traffic.

5 "Bot" traffic is related to software applications that run automated tasks (scripts) over the Internet, whereby other websites were connecting to PG&E's website to tie to PG&E's PSPS event maps and event updates.

6 PG&E pre-translated in 7 languages content for the PSPS event updates page to ensure the information could be published almost simultaneously throughout events in English, Spanish, Chinese, Vietnamese, Korean, Russian, and Tagalog. In addition, in-language instructions were provided for using the PSPS address lookup tool when available. The following number of unique visits were made to each of the translated sites for PSPS Updates from October 6 to 12: Spanish–3,527, Chinese–5,477, Tagalog–545, Russian–702, Vietnamese–1,075, Korean–1,045.

Due to the scale of the event, despite increasing site capacity, the PG&E website experienced scalability issues and was intermittently available to provide customers information.

On Wednesday evening October 9, PG&E coordinated with a state agency, California Department of Technology, to release a temporary third-party site with general area maps.[7] Though not as precise as the address lookup tool, customers could enter their address to see what areas were generally expected to be impacted. PG&E made customers aware of this new site through notifications to local government agencies and a press release for local news stations to share with the public.

PG&E is working to fortify online resources for future PSPS events. Key PSPS applications, such as the address lookup tool, are being rebuilt for the cloud, which will allow for PG&E to scale web traffic as needed during an event.

Customer Notifications

As described in section 4, customers were de-energized in four different phases based on weather timing in different geographic regions. Notifications were made throughout the event in accordance with these phases.

Throughout the afternoon of Monday, October 7, PG&E sent the first PSPS event notifications[8] to potentially impacted public safety partners, critical facilities, medical baseline and all general customers initially identified in Phases 1, 2, and 3. Soon after, PG&E sent automated notifications to potentially impacted transmission customers. PG&E notified customers currently enrolled in the Company's medical baseline program, including customers that are tenants of a master meter[9] and initiated the medical baseline door knock process[10] for over 6,800 customers that had not confirmed

---

[7] www.arcgis.com/apps/Cascade/index.html?appid=cb0658a472664835aa4defffc6d6868b.

[8] For potentially impacted customers, PSPS notifications were primarily delivered in English, or Spanish if language preference was available. Customers also had an option to listen or view the notification in Spanish if the language preference was unknown, or access event information translated in 240 languages by calling PG&E's Contact Center to access our Customer Service Representatives 24 hours a day during the event.

[9] Persons that meet the criteria of PG&E's medical baseline customers, but are not a PG&E account holder, can apply for the PG&E medical baseline program and indicate they are tenant of a master meter account with PG&E. Through this designation, they receive the medical baseline discounted rate allowance, and will also receive direct notifications by PG&E during a PSPS event, including the above process described for all medical baseline customers.

[10] For notifications during a PSPS event, medical baseline customers received automated calls, text and e-mails at the same intervals as the general customer notifications. In addition, these customers received repeat automated calls and texts at regular (hourly) intervals until the customer confirms receipt of the notifications by either answering the phone or responding to the text. If confirmation is not received, a PG&E representative visits the customer home to check on the customer (referred to as the "door knock process"). If the

receipt of the first automated notifications or did not have contact information on file. For all medical baseline customers, automatic notification retries were issued hourly within Telephone Consumer Protection Act (TCPA) curfew boundaries[11] in parallel to the door knock process. All notifications sent prior to de-energization were also sent to customers signed up for PG&E's PSPS Zip Code Alerts.

PG&E was in direct communication with eight telecommunication providers and nine impacted Community Choice Aggregators (CCA) throughout the event. PG&E representatives based in PG&E's local Operations Emergency Centers (OEC) provided localized support for other public safety partner critical facilities, such as water agencies and hospitals.

On October 8, the weather footprint expanded, resulting in the identification of additional customer impacts as a part of Phase 1, 2, and 3. A set of notifications were issued indicating power would be shutoff overnight. This set of notifications was the second notification for the majority of customers and the first notification for the customers identified in scope that morning. Around the same time on the morning of October 8, Customers in Phase 4 received their first notification that their power may be shutoff within 36 to 48 hours. (The scope identified, and therefore the customers notified, for phase 4 was large at this time, and subsequently narrowed on October 9.)

In the afternoon, it was confirmed that de-energization would start for Phase 1 customers overnight at approximately midnight and Phase 2 and 3 de-energizations would start at approximately 1500 on October 9. Customer notifications were sent accordingly. Phase 1 customers were notified power would be turned off overnight. Phase 2 and 3 customers were notified power may be turned off in 24 to 36 hours.

On the morning of October 9, Phase 2 and 3 customers, including tenants of a master meter medical baseline customers, received a notification that their power would soon be shutoff.

Also, on the morning of October 9, customers in Phase 4, including tenants of a master meter medical baseline customers, received notifications that their power would be shutoff within 24 hours. In the early afternoon of October 9, the Phase 4 scope was substantially reduced based on a narrowed and localized meteorological footprint using granular weather modeling. PG&E sent a cancellation notification to these customers on the evening of October 9, indicating that they would not be de-energized in the upcoming PSPS-related shutoff. At the same time, the remaining customers in Phase 4 area received a notification that their power would soon be shutoff.

---

customer does not answer, a door hanger is left at the home. In both cases the notification is considered successful.

[11] Curfew hours are between 2100 and 0800, whereby TCPA (under the rules of the Federal Communications Commission (FCC)), requires no automated calls or texts be made to customers during this window for telemarketing and advertisements. While PSPS notices do not fall under this prohibition, PG&E aims to align with these guidelines. However, PG&E will consider notifications during curfew hours on a case by case basis (e.g., calls to medical baseline customers during curfew hours due to suddenly changing conditions).

Approximately 23,000 customers out of the ~~729,000~~ 732,000 customers de-energized did not receive notifications prior to de-energization (approximately 500 of which were medical baseline customers). This was primarily due to the following reasons:

- No customer contact information on file;
- Abnormal switching configurations whereby customers could be operationally tied to one circuit that was impacted by the PSPS event, but their notifications were sent based on the normal circuit configurations which were not impacted; and
- Challenges related to a currently manual process of taking the areas identified as high-risk by meteorology, translating the areas into assets on the electric grid, and correlating to impacted customer currently requires manual steps.

Medical Baseline Customers

During PSPS events, PG&E continues to attempt contact with medical baseline customers if the Company is not able to confirm receipt of their notification. As part of PG&E's regular PSPS awareness campaign, all medical baseline customers received a postcard and e-mail (to those with e-mail on file) weeks prior to this event reminding them to be on alert to answer calls from 1-800-743-5002, respond to text notifications from 976-33 and to open e-mails from PGEcustomerservice@notifications.pge.com.

PG&E initially identified a total of approximately 31,000 medical baseline customers that could be potentially de-energized in this event. For the 84 medical baseline customers identified in the initial scope of the event that had no contact information on file, PG&E began immediately sending out representatives to these customers to confirm notification and to collect contact information, if possible. Of the ~~30,026~~ 30,077 medical baseline customers impacted, PG&E verified ~~29,144~~ 29,184 received notice prior to de-energization. A total of 28,177 confirmed receipt of a notification,[12] which included 5,080 door knocks. The medical baseline customers that did not confirm receipt of an automatic notification prior to de-energization had received multiple contact attempts.

Engagement With Local Partners That Support AFN Populations

PG&E continued their collaboration with the California Foundation for Independent Living Centers (CFILC) during this PSPS event in an effort to support vulnerable

---

[12] Contact with a customer is considered "successful" if one of the following occurs: Customer answers the phone or voice message is left, text message is delivered, or text is received back from the customer, e-mail is delivered or opened, or a link within the e-mail is clicked. Contact with a customer is considered "received" if one of the following occurs: Customer answers the phone, text is received back from the customer, or e-mail is opened or a link within the e-mail is clicked. For Non-Medical Baseline customers: two additional retries will be commenced in 10-minute intervals. For Medical Baseline customers: If a confirmation has not been received through system notifications, PG&E commences the door knock process, which is an in-person visit by PG&E personnel in parallel with system notifications occurring every hour (until curfew or PG&E suspends). PG&E will leave a door hanger at customer premise if possible.

populations, including medical baseline customers. CFILC is a California-based non-profit organization whose goal is to increase access and equal opportunity for populations with disabilities by building the capacity of independent living. PG&E has coordinated with CFILC to respond to customers that require continuous power for medical sustainability or need assistance charging medical devices during the PSPS event. CFILC experienced a high volume of calls to their local offices in impacted areas. PG&E sent press releases to CFILC so they could provide information to their consumers throughout the duration of the event.

Additionally, CFILC supported some of PG&E's escalations from PG&E's Contact Center and local offices by providing several Yeti 3000 batteries (less than 10) to customers in need of temporary backup power. They also referred customers to local resources through their existing community network and local agencies.

Section 7 – Local Community Representatives Contacted

PG&E sent out over 1300 notifications to over 160 city and county offices about this PSPS event. Appendix F shows the local government, tribal representatives, and CCAs contacted prior to de-energization, the initial date on which these stakeholders were contacted, and whether the areas affected by de-energization are classified as Zone 1, Tier 2 or Tier 3 as per the definition in GO 95, Rule 21.2-D. Dates marked with an asterisk are representatives who received multiple notifications during the event.

Section 8 – Local and State Public Safety Partner Engagement

Since 2018, PG&E has been meeting with cities, counties, tribes, state agencies and other public safety partners to provide information about PG&E's PSPS Program. This has included, but was not limited to:

- Reviewing key notification milestones with public safety partners;
- Identifying 24-hour contact numbers for all jurisdictions within PG&E's service area;
- Coordinating with cities and counties to confirm critical facilities in their jurisdictions;
- Establishing access to the secure data transfer portal and securing non-disclosure agreements (NDA) with cities and counties for additional customer information needed to assist local response efforts during an event; and
- Expanding outreach to key stakeholders and local communities regarding the increased scope of the program to include transmission-level assets and the importance of emergency preparedness.

In 2019, to date, PG&E has held 663 meetings with cities, counties, and public safety partners regarding PSPS, including 17 planning workshops attended by more than 930 public safety partners. Throughout the year, PG&E also held regular meetings with state agencies including the CPUC, Cal OES, and CAL FIRE and the other investor-owned utilities (IOU) regarding PSPS processes and standards.

On October 6, PG&E notified state agencies (Cal OES, CPUC, and Governor's Office) via e-mail and phone calls of a potential PSPS event. During the period in which PG&E's EOC was active, PG&E submitted and continued to provide updates to Cal OES via the PSPS State Notification Form and twice-daily State Executive Calls. Members of the CPUC, Cal OES, and CAL FIRE were also embedded in PG&E's EOC and received real-time status updates.

Public Safety Answering Points (PSAP), County OES and tribal emergency responders were notified of potentially impacted communities through live phone calls. During the period in which PG&E's EOC was active, County OES and tribal governments received status updates through the thrice-daily Operational Briefing calls. PG&E also identified a dedicated PG&E point-of-contact for each impacted County to respond to unique, local inquires. In addition, PG&E liaison representatives were embedded in the local jurisdiction's EOC as requested, and Sonoma County Board of Supervisors and County OES were embedded in PG&E's EOC and received real-time status updates.

Additional outreach took place in the form of automated e-mails, phone calls, and text messages to the contacts listed in Section 7 – *Local Community Representatives Contacted* at regular intervals.

Although PG&E successfully contacted all potentially impacted cities, counties, tribes, state agencies, and other public safety partners in advance of shutting off power, PG&E identified areas for continued improvement regarding engagement with its public safety partners. Please see Section 14 – *Lessons Learned From Event* for further detail. It is important to note that PG&E is in the process of reaching out to impacted communities to solicit feedback and identify further areas for partnership and improvement.

Section 9 – Number and Nature of Complaints Received

As of October 22, PG&E had received three written, three phone and one e-mail CPUC complaints. These complaints relate to:

- Questions about programs to purchase generators and a request that PG&E pays for the customer's generator;
- Feedback that medical baseline notifications are too frequent and wanted calls to stop;
- Questions related to why the power was shut off and when power would be restored;
- Request for credit during the shut off period;
- Two complaints that the customer did not receive notifications prior to de-energization; and
- Feedback that the website did not work during the event.

Section 10 – Claims Filed Because of PSPS Event

As of October 21, 2019, PG&E has received 450 claims for the Oct. 9-12 PSPS event. 407 of those claims were residential and 43 were commercial.

- Commercial:
  - 32 business interruption/economic loss
  - 5 property damage with business
  - 3 property damage
  - 3 food loss
- Residential:
  - 46 economic loss
  - 16 property damage with business
  - 86 property damage
  - 256 food loss
  - 2 unclassified
  - 1 bodily injury

Section 11 – Detailed Description of Steps Taken to Restore Power

An initial “all clear” was issued by the OIC at 1130 on October 10, after winds decreased below outage-producing thresholds for a portion of PG&E's service territory. Additional "all clear" decisions were made for the remaining impacted areas as weather decreased below outage-producing thresholds for the corresponding portion of PG&E's service territory. Before the all clear, PG&E had mobilized resources from non-impacted divisions to support the execution of the patrol and re-energization strategy. In support of safe restoration, PG&E patrolled all facilities starting within 15 minutes of each "all clear" decision on October 10th and 11th to identify any damage before re-energizing. To reduce the outage impact to customers, PG&E utilized helicopter patrols in areas where visibility was not limited by vegetation. Using the Incident Command System (ICS) as a base response framework, each circuit was assigned a taskforce consisting of supervisors, crews, troublemen, and inspectors. This structure allowed PG&E to patrol and perform step restoration in alignment with the impacted centralized control centers. Over 25,000 circuit miles were visually patrolled for safety. PG&E utilized approximately 6,000 field personnel and 44 helicopters to identify any safety concerns and make necessary repairs prior to restoration. PG&E restored power to customers as patrols were completed and completely restored service to all customers at approximately 1800 on October 12.

Section 12 – Sectionalization

During this event, PG&E determined that it could implement PSPS for 46 of the in-scope circuits by sectionalizing and de-energizing only portions of each circuit (as opposed to the full circuit). Those 46 circuits are marked with a single asterisk in Table 1. This reduced the number of customers impacted by this PSPS event by 77,152 customers.

Section 13 – Community Assistance Locations

PG&E considers CRCs and Resilience Zones (RZ) as Community Assistance Locations, as well as backup generation support. This section describes these resources made available to customers during this PSPS event.

Resilience Zones

A RZ is a designated area where PG&E can safely provide electricity to community resources by rapidly isolating it from the wider grid and re-energizing it using temporary mobile generation at a pre-installed interconnection hub (PIH) during an outage. Though each RZ will vary in scale and scope, the following equipment will enable each site:

- Isolation devices used to disconnect the circuit from the wider grid during a public safety outage; and
- A PIH that enables PG&E to rapidly connect temporary primary generation and energize the isolated circuit (thereby forming an energized "island").

Note that while PG&E's objective is to provide power continuity in RZs to support community normalcy, PG&E is not in a position to guarantee service on behalf of any customer energized within a RZ.

During this PSPS event, PG&E readied and executed plans to further mitigate the impacts of de-energization on customers by safely sectionalizing and energizing pre-defined areas in Angwin and Calistoga using temporary primary generation beginning the morning of Tuesday, October 8 through late evening Thursday, October 10. These pilot efforts are paving the way for PG&E to scale up its ability to safely provide power continuity using temporary generation during PSPS events to more communities, and thereby reduce the footprint of PSPS.

The Angwin RZ, PG&E's first pilot RZ, energized a sectionalized an area of the town that included the local fire department and student housing during this PSPS event. Mobile generators were staged and connected at the PIH.

Figure 1 – Approximate Area Served by PG&E Resilience Zone in Angwin

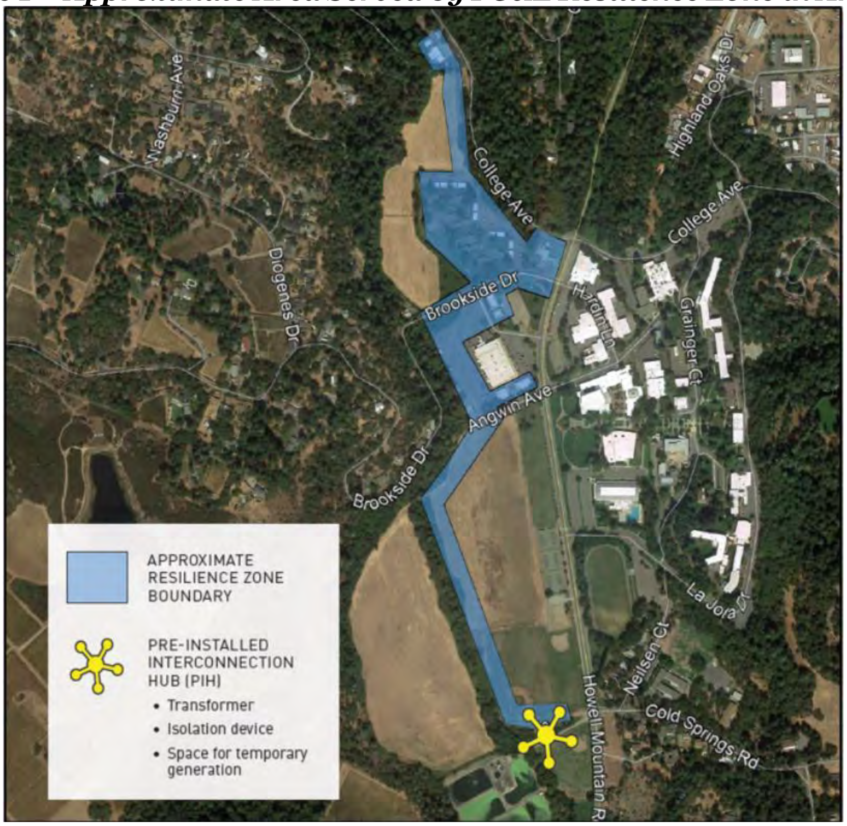


Figure 2 – Mobile Generation Staged at Angwin PIH

PG&E has an in-flight project with the City of Calistoga to deploy a PIH that is currently in the design phase. Calistoga was targeted for the development of a PIH because despite its location outside of the CPUC's Tier 2 and Tier 3 fire-threat areas, the 60 kilovolt lines that feed its substation run through Tier 2 and 3 areas in FIAs 175/180 that have been in-scope for PSPS numerous times, making Calistoga one of the towns most likely to be impacted by PSPS events. Calistoga also presents PG&E the opportunity to pilot a PIH configuration and processes to support a significantly larger RZ than that found in Angwin.

Although Calistoga does not yet have a PIH in place, PG&E used temporary primary generators that were already stationed at the local substation for other work to energize a portion of Calistoga that had previously been confirmed as safe to energize during PSPS weather conditions.

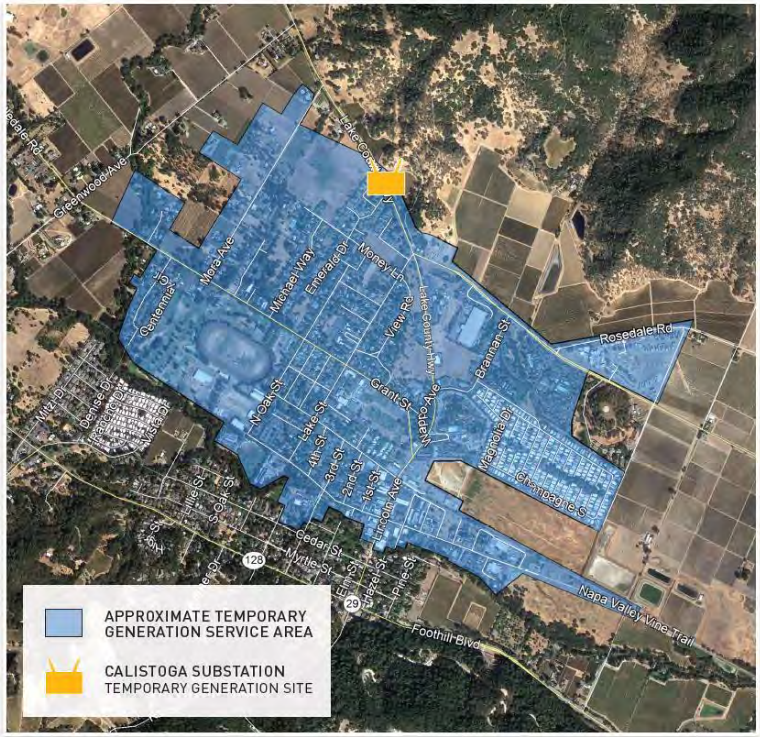
<u>RZ Site Selection Considerations (2020)</u>

In determining the locations of potential future RZs, PG&E's targeting process begins by considering communities that are most likely to experience PSPS. For those communities, PG&E assesses solution fit by looking for:

- Clusters of shared services in downtown corridors that can support community normalcy;
- Electric infrastructure that is safe to energize during a PSPS event (e.g., minimal vegetation concerns, hardened infrastructure);
- Higher potential for longer outages based on location and the electric infrastructure serving the area; and
- Distance to areas that are less likely to experience a PSPS event.

PG&E will finalize its targeting decisions by taking into account implementation feasibility and the feedback of its Public Safety Partners about population vulnerability and critical infrastructure.

Figure 3 – Approximate Area Served by PG&E Resilience Zone in Calistoga



Community Resource Centers

When a PSPS event occurs, CRCs provide impacted customers and residents a space that is safe, energized and air-conditioned (as applicable) during daylight hours. Visitors are provided with up-to-date PSPS event information by dedicated PG&E staff, water and restrooms, tables and chairs, as well as power strips to meet basic charging needs, including charging for cell phones and laptops, small medical devices and Wi-Fi access (where possible). The CRCs are designed to meet the following criteria: Americans with Disabilities Act (ADA) compliant,[13] capable of accommodating up to approximately 100 customers at a time, site owner approval, and open typically from 8 a.m. to 6 p.m.[14,15]

In advance of a potential PSPS event, PG&E has coordinated with local government agencies in an effort to gain input and pre-identify ideal site locations for a CRC during an event that meet the criteria noted above. In order to simplify and accelerate the

---

13 All of PG&E's CRC structures are designed as ADA compliant. Going forward, PG&E will work in coordination with local agencies to ensure CRCs are sited in areas that are ADA accessible, such as near ADA compliant transportation hubs.

14 CRCs may close early if outage is fully restored in the area or if any safety concerns are identified. Some CRCs remained opened past 6 p.m. if there was demand from the community, no safety concerns at hand, and public safety officials were present to support security to the location(s).

15 Based on feedback received during this event, PG&E's CRC hours have been extended to 8 a.m. to 8 p.m.

logistical process of mobilizing a CRC within one day, PG&E has several standing agreements in place, as well as potential site locations identified for when a PSPS event is called. While these pre-identified locations are developed to simplify and optimize the mobilization of a CRC, the proximity of these locations to the nearest outages can vary based on the geography of the region and the locations meeting the following requirements: capacity of at least 100 people, ADA accessibility, back-up generation availability, safety needs, and approval from the property owner.

Location, Type, and Timeline of CRCs: During this PSPS event, PG&E received suggested CRC locations from public safety partners that would be more convenient for customers based on the outage areas; however, there were several constraints in place and some suggested sites could not meet these criteria noted above, which is why some seemingly more appropriate locations were not used.

Due to the scale of this PSPS event, PG&E provided a total of 33 CRCs throughout the impacted areas in the territory with the intent of having at least one CRC in the counties affected. Three of the 33 CRCs were indoor locations: Alcouffe Community Center in Oregon House, Clearlake Senior Center in Clearlake, and Hanna Boys Center in Sonoma. The remaining were temporary trailers or tented locations in an open space, such as a parking lot or grassy area at a shopping center, church, stadium, restaurant, fire station, hotel, amusement park, community center, and fairground.

On Wednesday, October 9, PG&E opened 28 CRCs across 25 counties. On Thursday, October 10, five additional CRCs were opened based on feedback from public safety partners and the anticipated time of de-energization in the surrounding areas. A total of 33 CRCs in 28 counties were available to the public on Thursday. On Friday, October 11, several CRCs were demobilized (closed) after some locations had service restored or attendance was minimal. A total of 27 CRCs remained open across 22 counties on Friday. With most customers restored by Friday evening, PG&E kept four CRCs open on Saturday, October 12 in four counties until power was restored to the areas.

Customer Visitation: Overall, approximately 5,300 visitors attended one of the 33 CRCs to use the services provided by PG&E. Some customers returned to the CRCs across multiple days and the length of stay varied—from a short visit to charge a phone or medical equipment and get PSPS-related information to spending most of the day to use the Wi-Fi while working. Additionally, PG&E received a total of 76 visitors from the media across these 33 locations. Customer attendance was highest in Grass Valley with almost 900 people attending across the four days it was open. The CRCs in Clear Lake, Auburn and Sonoma, each had over 400 in attendance across the three days they were open.

See Appendix G for further details on the CRCs that PG&E mobilized during the PSPS event, including specific locations, dates and times available, and total number of visitors that utilized the CRCs' services.

See Appendix G for a list of the CRCs offered by different agencies that PG&E is aware of. Specific providers are unknown, and the list is not exhaustive.

Figure 4 – PG&E Community Center in Oakland, Alameda County

Figure 5 – PG&E Community Center in Pioneer, Amador County

Figure 6 – PG&E Community Center in Oroville, Butte County

Figure 7 – PG&E Community Center in Magalia, Butte County

<u>Backup Power Support for Exceptional Circumstances Impacting Public Safety During a PSPS Event</u>

PG&E's standard for deploying portable generators to supply temporary power during planned or unplanned outages prioritizes critical societal infrastructure if de-energizing the facilities is deemed a high risk to public safety, the environment, or to essential emergency support facilities.

During this event, PG&E deployed over 9 megawatts (MW) of mobile generation to 10 sites at the request of customers to mitigate public safety risks, including 6 MW to the Caldecott Tunnel, as well as 3 MW of smaller units to support multiple public water utilities' pumping stations, Bay Area Rapid Transit (BART) facilities, multiple critical medical care locations, county's EOC and law enforcement facilities, a mine's wastewater diversion system.

Generation was deployed to an 11th site which included a PSPS critical helicopter hanger to support restoration efforts. PG&E's EOC staffed personnel 24 hours per day to intake elevated customer concerns and manage generator deployments.

In addition to these deployments, an additional 11 generator units were deployed to pre-established RZs and PG&E field crew housing.

Figure 8 – Mobile Generation at PSPS-Critical Helicopter Hangar

Figure 9 – Mobile Generation at a County Water District Facility

Figure 10 – Mobile Generation at Caldecott Tunnel

Photo credit: Ben Margot, Associated Press

Section 14 – Lessons Learned From Event

PG&E recognizes that there were significant shortcomings in its execution of this PSPS event. PG&E is committed to hearing and acting on the feedback received from local agencies and community partners, and all stakeholders.

Below are the high-level lessons learned and steps PG&E is taking to remedy those items.

Communications

A significant area of improvement for PG&E based on the feedback received is around communications; PG&E is committed to improving PSPS communications with our customers and communities with as much notice as possible, clarity as possible, and as frequently as needed.

Some of the communication issues that occurred were:

- Requests to PG&E's website increased by more than 250 times, from approximately 7,000 user requests per hour to more than 1.7 million user requests per hour, which impacted performance of the website and caused it to crash several times;
- PG&E experienced surges in call volume aligned with customer outbound notifications that exceeded its plan. This combined with the website capacity issues created several spikes on Monday, October 7 and Tuesday, October 8 in calls to PG&E contact centers, which were overloaded. PG&E did not respond to PSPS calls soon enough, leaving customers with longer than desired wait times;

- Operations Briefing call to provide overall situational awareness was not clearly established or enforced early on, and with the increase in participants from 200 to 1,000 at peak, necessitated a change in format and technology; and
- Agency portal and data access was problematic, untimely, and confusing.

Website: PG&E's website was a major area of frustration from our customers and public safety partners during this event, and the Company is committed to remedying this issue. In direct response, PG&E has moved specific components and features of the website to cloud-based solutions that can scale up as needed. These features include those most heavily used during an event (e.g., address look up, file download). These sites are being performance-tested and simulate an external load of up to 1 million users accessing the site in two minutes. This is more than double the number of users that accessed the site in two minutes during this event.

Contact Center: PG&E is also reinforcing call centers to handle a much higher volume. Going forward, PG&E will leverage the PSPS Call Strategy when a PSPS event scales to over 100,000 potentially impacted customers, as needed. This includes only accepting emergency calls related to PSPS, down wires, gas leaks, and outages when initial notifications are sent to customers for an active PSPS event. PG&E may also provide upfront interactive voice recordings (IVR) messaging intended to allow customers to self-serve on the website and utilize multiple staffing levers to supplement existing personnel in the Contact Centers. These levers include: maximizing staffing, and training Billing and Credit Customer Service Representatives. This PSPS Call Strategy can be reconsidered when call volume can be handled to meet the required response time goals with the additional support measures in place, e.g., staffing and upfront IVR.

Operations Briefing: For Operations Briefings, PG&E recognized the issue mid-event and implemented new tools and meeting format. PG&E moved from twice-daily operational briefings with local agencies to thrice-daily briefings, began utilizing a conference line with an operator, and using WebEx to allow for the ability to view documents. PG&E will consider a regional call structure for future large-scale events, as suggested by the CPUC, while also keeping in mind that many counties indicated a preference for a single call with a more streamlined structure.

Agency Portal: At times, public safety partners were also unable to access the secure data transfer portal. To enable more efficient data product sharing, PG&E is now working on a sharing process using an online GIS portal, which will be available later this wildfire season. In the meantime, PG&E will continue to work with agencies to provide access to the secure data transfer portal and securing NDAs for additional customer information needed to assist local response efforts during an event.

Sectionalization: PG&E understands the hardship these events place on our customers and communities and will continue to work on narrowing the scope of safety shutoffs by implementing the following: adjusting the timing of de-energization and/or re-energization if the weather changes, looking to increase the number of weather stations (to provide more precise local data), as well as seeking to implement additional circuit sectionalizing.

PG&E recognizes that customer notifications are inherently tied to the scope and timing of the PSPS event, which is dependent upon changing weather conditions. For these reasons, some customers may have received advanced notification of a possible shut off, but in fact were not shut off. This is not optimal and creates unnecessary hardship for our customers. Additional customer notification scripts will be developed that provide improved information about shifting weather conditions and the associated shifts in timing of potential shutoffs. Enhanced tools need to be developed that are better equipped to provide timely customer updates. Ultimately, PG&E's goal is to minimize the impact to customers and be as accurate as possible and more targeted in our customer notifications.

Agency Coordination and Unified Command Structure

Another key area of improvement required relates to PG&E's coordination efforts. Ensuring that PG&E is appropriately aligned with state and government agencies such as Cal OES and CAL FIRE to create a unified command structure is key to successful execution of future PSPS events.

Some of the coordination issues that occurred were:

- Some customers were sent notifications by their county when they were not in-scope for safety shutoff due to lack of coordination in distinguishing which notifications that were intended to be more targeted (at the identified circuit level) versus all customers within a county;
- Coordination break-downs and difficulty solving issues in real-time between PG&E and impacted county and tribal liaison; and
- Concerns with assisting customers with AFN during an extended outage related to a PSPS event.

Agency Notifications: Coordinating communication with city and county Offices of Emergency Services is also an area for PG&E to improve upon. During the event, PG&E coordinated with the 30+ counties impacted by the shutoff. Many local county OESs, in turn shared notifications to residents in their communities to prepare for the PSPS-related outage. PG&E will look to enhance coordination with county OESs to distinguish customers that will be impacted by safety shutoff due to targeted circuit compared to the other customers within that county to avoid confusion related to which customers would be impacted.

Staffing of Local County EOCs: During the event, PG&E received requests from counties for a PG&E liaison representative to be embedded in their EOC. In response, PG&E mobilized dedicated PG&E liaison representatives to the local EOCs of those impacted jurisdictions who expressed interest, including Napa, Sonoma, Santa Clara, Calaveras, Butte, and Nevada Counties. These liaison representatives had direct communication with PG&E's EOC and were able to resolve any local issues in real-time. Moving forward, PG&E will continue to make dedicated county and tribal liaison representatives available to embed in a local jurisdiction's EOC, if one has been activated and a PG&E liaison is requested.

Information Sharing: During the event, PG&E identified points-of-contacts for each potentially impacted county and tribal government to respond to unique, local inquires. These points-of-contacts had direct communication with PG&E's EOC. PG&E intends to leverage this model for future events.

Another mechanism to enhance the partnership between PG&E and the Tribes and Counties is to provide more information on how their local jurisdiction is served by the electric grid. PG&E will provide more transparency into operation of the grid and how PSPS events will likely be executed in their area as a result, to aid in planning, including:

- What facilities are on what circuits;
- How the local grid is configured;
- What areas are likely to be affected by a PSPS;
- The expected sequencing for restoration; and
- PG&E has done this with certain Counties that have asked for more specific information, but the Company will be doing this systematically with all counties and tribes and in the coming months.

<u>SEMS Training</u>: To better align with Cal OES and CAL FIRE, PG&E will be training all PG&E PSPS event and emergency response teams to the Standardized Emergency Management System (SEMS) standard.

<u>Access and Functional Needs Support</u>: PG&E continues to receive requests from various organizations, persons and agencies regarding how PG&E can further assist AFN populations. PG&E will continue to engage Community Based Organizations that currently serve the AFN population and have an expertise in meeting the needs of this population as part of their mission. In the future PSPS events, PG&E will continue their collaboration with the CFILC and increase the scope of their assistance to customers to potentially include: accessible transportation to CRCs or hotel vouchers for customers that require continuous power for medical sustainability, including accessible transportation to a hotel, as needed. PG&E will also direct customers to more specific organizations that may offer customers assistance during an event and provide this information in press releases, talking points, and online.

<u>Community Resource Centers</u>

It is understood that PG&E missed the mark on collaborating with the counties and tribes on where to locate the CRC facilities. Going forward, for all events, site selection will be a collaborative process with the counties and tribes. PG&E is developing a more effective plan for working with local governments to understand their needs and preferences for location of CRCs, while also updating criteria to include cell service availability. PG&E plans to re-circulate the list of planned CRC sites to cities and counties and continue to solicit feedback on preferred locations for local governments.

Online Maps

Another major issue experienced during this event were the distributed outage maps. Public safety partners shared feedback that the outage maps did not always reflect the clear boundaries of the PSPS outage area. Prior to the event, PG&E received and incorporated input from Cal OES on the methodology for creating buffered outage polygons used to illustrate impact areas on these maps, as well as alignment on data summary files.

These maps showing potentially impacted areas were not dependable and demonstrated a lack of precision. Maps were being used to check specific facilities that were impacted—in particular those facilities on the PSPS outage boundaries. Facilities on the boundaries were attempted to be verified using PG&E's online address checker tool, which was not available given PG&E's website issues. In the future, PG&E will be drawing tighter polygons, making GIS experts available to visit the County EOCs or assist with mapping questions to provide a more seamless data transfer for County EOC GIS needs, and developing the capability for counties and tribes to use the PG&E address checker tool with batches of facilities.

Societal Continuity Issues

PG&E is aware that they need to do a better job of planning for how a PSPS event will impact key infrastructure throughout its service territory, including bridges, tunnels, and mass-transit systems including BART, light-rail systems, and others. During this PSPS event, PG&E was able to successfully work with Caltrans, BART and other agencies to keep tunnels and tracks energized. However, this took place during the execution of the event. Instead, PG&E needs to identify this infrastructure prior to an event. Working with partner agencies, PG&E needs to understand what kind of backup power will be needed to keep these facilities fully operational. This is intended to be done with a robust inventory at the city and county level. PG&E will coordinate with Cal OES, customer agencies, and other California IOUs for assistance with leading a comprehensive review of potential customer impacts of PSPS, as well as other extended outages (e.g., earthquakes), on all major transit providers, refineries, and businesses dependent on fuels for operations.

Grid Preparedness

PG&E needs to ensure that all circuits, especially within the PSPS footprint, are in-service. Some lines were out-of-service due to maintenance or other issues and resulted in customers in Humboldt County being de-energized when they did not need to be.

Restoration

Past messaging to customers, stakeholders and PG&E's regulators has been that preparations should be made for outages lasting three to five days after the "all clear" weather signal is given. PG&E recognizes that five days as a benchmark is not acceptable. For this PSPS event, the majority of customers were restored within 48 hours, which will be the benchmark going forward. In future PSPS events, PG&E will resource every circuit with a dedicated restoration team. If that requires mutual-assistance, the Company will ask for assistance earlier in the process and have outside crews staged before restoration begins. PG&E is also partnering with Cal OES and California Highway Patrol to investigate the possibility of doing aerial patrols at night, further decreasing the time the time required for restoration.

Since the program began, we have learned valuable lessons that will help to shape how we conduct future events, both in our operations and our communications. We will take this feedback from our external partners and customers to further assess how we can improve the PSPS process.

Section 15 – Proposed Updates to ESRB-8

PG&E continues to work through the implementation of the de-energization guidelines and appreciates that there is opportunity to refine certain aspects of its guidelines. PG&E is actively addressing these issues with the CPUC, Cal OES, and CAL FIRE. Phase II of the CPUC's de-energization proceeding will continue to refine aspects of the de-energization guidelines adopted by Decision 19-05-042 and Resolution ESRB-8, including the development of a formal post de-energization reporting template. PG&E will continue to actively engage in that proceeding, and has no further suggestions at this time.

Section 16 – Other Relevant Information to Help the Commission Assessment of Reasonableness of Decision to De-Energize

Background on OPWs

PG&E's OPW Model converts forecasted wind speed from the POMMS model into an outage percentage, which represents the historical frequency of hours that unplanned outage activity was observed at a given wind speed. The OPW model was constructed using PG&E unplanned outage data from 2008-2018 and PG&E's high-resolution climatology model, which contains 30 years of hourly wind data at 3 kilometer (km) spatial resolution (>5 billion data points of wind). The same model and configuration used to construct the weather climatology is used in forecast mode to produce OPW forecasts. This consistency between historical and forecast data allows PG&E to apply wind outage correlations found in the historical data to a forecast model. The OPW model is location-specific because wind-outage response is heterogeneous across PG&E's territory depending on vegetation, climatological wind exposure, and topography, among other factors. In addition, PG&E utilizes the Weather Research and Forecasting (WRF) model for high resolution modeling purposes and maintains active partnerships with external experts in numerical weather prediction on this front.

Background on Utility FPI

The PG&E Utility FPI model was calibrated against fires in the PG&E territory from 1992-2018 and combines weather (wind, temperature, and relative humidity) and fuels (10-hour dead-fuel moisture, live fuel moisture, and fuel type) and aligns to the fire spread element of the National Fire Danger Ratings System. The FPI output represents the probability of significant fires occurring and its output on the same domain as PG&E's high-resolution weather model, POMMS. The FPI output is also ranked on a scale from R1 (lowest) to R5 (highest) with R5 indicating a very high potential for significant fires. The highest level, R5-Plus, indicates high fire danger plus the potential for OPWs.

OPW Forecast vs Damages from October 9 PSPS Event

PG&E's OPW forecast for this event averaged 33 percent at locations where asset damage and hazards were found. The damages and hazards found aligned with PG&E's expectations based on the OPW model forecasts.

FPI Forecast vs Historical Fires

PG&E compared the FPI forecast for this weather event to the FPI at the time and location of nearly 1,600 historical fire ignitions from the US Forest Service Databases of historical fires greater than 40,000 acres since 1992.

The FPI forecasted over this weather event at the locations of notable historical fires is generally similar to the historical FPI, indicating that comparable fires were possible under the critical fire conditions observed during this weather event.

Maximum Wind and Gust Speeds

The table below shows the maximum wind and gust speeds recorded by weather stations in the general timeframe and vicinity of the PSPS location:

Table 2 – Windspeeds by County

County	Date of Max Wind Gust (Pacific Daylight Time (PDT))	Station	FIA	Windspeed at Time of Maximum Gust (mph)[(a)]	Maximum Observed Gust (mph)[(b)]
Sonoma	10/10/2019 0410	PG132	175	68	77
Contra Costa	10/10/2019 0320	SJS02	530	55	75
Tehama	10/10/2019 0627	CBXC1	248	29	61
Tulare	10/9/2019 1510	BPKC1	445	45	61
Sierra	10/10/2019 0518	SLEC1	350	29	59
Butte	10/10/2019 0730	PG328	248	26	56
Los Angeles	10/10/2019 1153	KSDB	NA	38	54

Table 2 – Windspeeds by County (Continued)

County	Date of Max Wind Gust (Pacific Daylight Time (PDT))	Station	FIA	Windspeed at Time of Maximum Gust (mph)[(a)]	Maximum Observed Gust (mph)[(b)]
Napa	10/10/2019 0010	PG358	175	24	54
Santa Cruz	10/9/2019 2230	PG370	520	34	54
Placer	10/10/2019 0318	DUCC1	350	34	53
Solano	10/9/2019 2310	PG583	177	33	53
Yolo	10/10/2019 0320	PG490	177	32	53
Humboldt	10/9/2019 0608	PTEC1	105	29	52
Kern	10/10/2019 1413	GVPC1	651	29	51
Lake	10/10/2019 0809	KNXC1	175	31	51
Mendocino	10/10/2019 0104	MASC1	165	24	51
Santa Barbara	10/9/2019 2009	GVTC1	512	32	50
Shasta	10/9/2019 0720	PG473	244	32	49
Calaveras	10/9/2019 2254	STUC1	360	32	49
Alameda	10/10/2019 0128	RSPC1	535	23	48
Colusa	10/10/2019 0900	PG301	177	31	47
San Luis Obispo	10/11/2019 0310	PG569	575	33	46
El Dorado	10/10/2019 0536	BDMC1	335	13	46
Marin	10/10/2019 0710	PG521	180	25	40
Del Norte	10/9/2019 0957	SHXC1	110	23	39
Lassen	10/9/2019 0411	HDVC1	262	8	39
Yuba	10/10/2019 0310	PKCC1	282	18	39
San Mateo	10/10/2019 0340	PG605	518	22	38
Fresno	10/10/2019 0552	MMTC1	450	26	38
Stanislaus	10/10/2019 0600	DBLC1	540	14	38
Glenn	10/9/2019 1010	PG563	246	17	38
Plumas	10/10/2019 1847	CHAC1	285	19	37

Table 2 – Windspeeds by County
(Continued)

County	Date of Max Wind Gust (Pacific Daylight Time (PDT))	Station	FIA	Windspeed at Time of Maximum Gust (mph)[(a)]	Maximum Observed Gust (mph)[(b)]
Amador	10/10/2019 0300	PG178	335	22	37
Santa Clara	10/10/2019 0330	PG483	530	13	36
Ventura	10/10/2019 1222	OZNC1	588	19	35
Mono	10/9/2019 1349	BPOC1	460	22	34
Nevada	10/9/2019 2250	PG500	354	16	33
San Benito	10/10/2019 2357	SRTC1	495	19	33
Monterey	10/11/2019 1130	PG543	525	24	33
Inyo	10/9/2019 1254	OVRC1	461	12	32
Trinity	10/9/2019 0132	BABC1	230	12	32
Tuolumne	10/10/2019 0102	MOUC1	348	21	31
Modoc	10/9/2019 0703	RSHC1	255	8	25
Siskiyou	10/10/2019 0315	RNDC1	255	8	24
Mariposa	10/9/2019 16:00	PG459	320	14	23
Madera	10/10/2019 1120	PG428	424	4	22
Alpine	10/9/2019 0248	MKEC1	385	7	20

(a) The windspeed at time of maximum gust is the average windspeed of the 3-5 second gust.
(b) The maximum observed gust is the maximum windspeed measured during the gust.

AMENDED PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

SECTION 1 – EXPLANATION OF PG&E'S DECISION TO DE-ENERGIZE

Table 1-1. Counties With Red Flag Warning 10/9/2019 – 10/10/2019

ALAMEDA	SACRAMENTO
ALPINE	SAN FRANCISCO
AMADOR	SAN JOAQUIN
BUTTE	SAN MATEO
CALAVERAS	SANTA CLARA
COLUSA	SANTA CRUZ
CONTRA COSTA	SHASTA
EL DORADO	SIERRA
GLENN	SOLANO
HUMBOLDT	SONOMA
KERN	STANISLAUS
LAKE	SUTTER
LASSEN	TEHAMA
MARIN	TRINITY
MENDOCINO	TULARE
NAPA	TUOLUMNE
NEVADA	YOLO
PLACER	YUBA
PLUMAS	

Table 1-2. Counties With "High Risk" Predicted From North and South Ops Predictive Services in PG&E Service Territory 10/9/2019 – 10/10/2019

ALAMEDA	SAN FRANCISCO
ALPINE	SAN JOAQUIN
AMADOR	SAN LUIS OBISPO
BUTTE	SAN MATEO
COLUSA	SANTA BARBARA
CONTRA COSTA	SANTA CLARA
EL DORADO	SANTA CRUZ
GLENN	SHASTA
KERN	SIERRA
LAKE	SOLANO
LASSEN	SONOMA
MARIN	STANISLAUS
MENDOCINO	SUTTER
NAPA	TEHAMA
NEVADA	TRINITY
PLACER	YOLO
PLUMAS	YUBA
SACRAMENTO	

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

SECTION 3 – TIME, PLACE, AND DURATION

Table 1-1. Distribution

Circuits labeled as "non HFTD" are located outside of the CPUC High Fire-Threat District (HFTD). These circuits or portions of circuits are impacted for one of two reasons: (1) indirect impacts from transmission lines being de-energized or (2) the non-HFTD portion of the circuit are conductive to the HFTD at some point in the path to service.Circuits with an asterisk (*) were sectionalized during the event to further reduce customer impact.

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time
ALLEGHANY 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:31	ALLEGHANY, CALPINE, COURTLAND, DOWNIEVILLE, GOODYEARS BAR, SIERRA CITY	10/12/19 12:57
ALLEGHANY 1102	TIER 3	10/09/2019 03:36	ALLEGHANY, NEVADA CITY, WASHINGTON	10/11/19 18:03
ALTO 1120*	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:19	MILL VALLEY	10/10/19 15:31
ALTO 1125*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 00:27	MILL VALLEY, SAUSALITO, STINSON BEACH	10/11/19 10:52
ANDERSON 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 03:27	ANDERSON, COTTONWOOD	10/11/19 9:58
ANDERSON 1102	NON HFTD	10/09/2019 03:24	ANDERSON	10/10/19 21:09
ANDERSON 1103	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 03:20	ANDERSON, FAIRFIELD, MILLVILLE, PALO CEDRO, REDDING	10/11/19 16:58
ANITA 1106*	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 01:08	CHICO	10/10/19 17:34
ANNAPOLIS 1101	TIER 2	10/09/2019 02:50	ANNAPOLIS, CAZADERO, STEWARTS POINT	10/11/19 11:27
APPLE HILL 1104	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 05:42	CAMINO, EL DORADO HILLS, PLACERVILLE, POLLOCK PINES	10/11/19 16:38
APPLE HILL 2102[1]	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 05:19	CAMINO, EL DORADO, FIDDLETOWN, GRIZZLY FLATS, MOUNT AUKUM, PLACERVILLE, PLYMOUTH, POLLOCK PINES, SHINGLE SPRINGS, SOMERSET	10/11/19 17:54
ARBUCKLE 1104	TIER 2	10/09/2019 00:27	ARBUCKLE, DUNNIGAN, WILLIAMS	10/10/19 15:30
ARCATA 1105	NON HFTD	10/09/2019 03:31	ARCATA, MCKINLEYVILLE	10/10/19 2:37

[1] Due to abnormal switching the outages on Apple Hill 1103 are reported as part of the Apple Hill 2102 circuit.

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time
ARCATA 1106	NON HFTD	10/09/2019 03:32	ARCATA	10/10/19 2:42
ARCATA 1121	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:30	ARCATA, BAYSIDE, MCKINLEYVILLE	10/10/19 1:41
ARCATA 1122	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:34	ARCATA, BAYSIDE, EUREKA, KNEELAND	10/10/19 3:00
ARCATA 1123	NON HFTD	10/09/2019 03:33	ARCATA	10/10/19 2:45
ARVIN 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/10/2019 09:47	ARVIN, BAKERSFIELD, LAMONT	10/11/19 16:00
AUBURN 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 04:31	AUBURN	10/10/19 20:12
AUBURN 1102	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 04:31	AUBURN	10/10/19 20:15
BANGOR 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:07	BANGOR, BROWNS VALLEY, BROWNSVILLE, DOBBINS, MARYSVILLE, OREGON HOUSE, OROVILLE, RACKERBY, SACRAMENTO	10/11/19 20:07
BASALT 1106	TIER 2	10/09/2019 00:39	NAPA, SONOMA	10/10/19 22:28
BEAR VALLEY 2105*	TIER 2, TIER 3	10/09/2019 15:47	CHOWCHILLA, COULTERVILLE, GROVELAND, MARIPOSA, SOLEDAD	10/11/19 11:40
BELL 1107	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:20	AUBURN, WILTON	10/10/19 19:13
BELL 1108	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:16	AUBURN, MEADOW VISTA	10/10/19 20:33
BELL 1109	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:14	AUBURN	10/10/19 18:29
BELL 1110	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:11	AUBURN	10/10/19 15:26
BELLEVUE 2103*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:48	PENNGROVE, ROHNERT PARK, SANTA ROSA	10/11/19 15:47
BEN LOMOND 0401	TIER 3	10/10/2019 10:53	BEN LOMOND, BOULDER CREEK, FELTON	10/11/19 20:08

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time
BEN LOMOND 1101	TIER 3	10/09/2019 23:10	BEN LOMOND, BOULDER CREEK, BROOKDALE	10/11/19 19:32
BIG BASIN 1101	TIER 3	10/09/2019 23:15	BOULDER CREEK, SANTA CRUZ, WATSONVILLE	10/11/19 17:35
BIG BASIN 1102	TIER 2, TIER 3	10/09/2019 23:27	BEN LOMOND, BOULDER CREEK, LOS GATOS, SANTA CRUZ, STOCKTON	10/12/19 12:10
BIG BEND 1101	TIER 2, TIER 3	10/09/2019 00:45	OROVILLE	10/11/19 17:41
BIG BEND 1102	TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 00:45	BERRY CREEK, OROVILLE	10/11/19 16:28
BIG LAGOON 1101	NON HFTD	10/09/2019 03:36	ORICK, TRINIDAD	10/10/19 4:20
BIG TREES 0402	TIER 2, TIER 3, PARTIALLY OUTSIDE	10/10/2019 00:30	FELTON, SANTA CRUZ	10/11/19 15:04
BLUE LAKE 1101	NON HFTD	10/09/2019 03:38	ARCATA, BLUE LAKE, KORBEL	10/10/19 4:14
BLUE LAKE 1102	NON HFTD	10/09/2019 03:39	ARCATA, BAYSIDE, BLUE LAKE, MCKINLEYVILLE	10/10/19 4:14
BOLINAS 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 00:45	BOLINAS, FAIRFAX, MILL VALLEY, OLEMA, STINSON BEACH	10/11/19 15:54
BONNIE NOOK 1101	TIER 3	10/09/2019 03:21	ALTA, COLFAX, DUTCH FLAT, GOLD RUN	10/11/19 19:02
BONNIE NOOK 1102	TIER 3	10/09/2019 03:25	ALTA, DUTCH FLAT, GOLD RUN	10/11/19 16:01
BRIDGEVILLE 1101	TIER 2, TIER 3	10/09/2019 08:13	BRIDGEVILLE, CARLOTTA	10/10/19 0:20
BRIDGEVILLE 1102	TIER 2, TIER 3	10/09/2019 08:14	BLOCKSBURG, BRIDGEVILLE, CARLOTTA, MAD RIVER	10/10/19 2:06
BROWNS VALLEY 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:41	BROWNS VALLEY, LOOMIS, MARYSVILLE, SMARTSVILLE	10/11/19 9:35
BRUNSWICK 1102	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 04:49	GRASS VALLEY, NEVADA CITY	10/11/19 16:00
BRUNSWICK 1103	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 04:55	AUBURN, GRASS VALLEY, NEVADA CITY	10/11/19 17:20

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time
BRUNSWICK 1104	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 05:03	GRASS VALLEY, NEVADA CITY	10/12/19 10:19
BRUNSWICK 1105	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 05:11	GRASS VALLEY, NEVADA CITY	10/12/19 11:30
BRUNSWICK 1106	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 05:25	CEDAR RIDGE, CHICAGO PARK, DIAMOND SPRINGS, GRASS VALLEY, NEVADA CITY	10/12/19 10:57
BRUNSWICK 1107	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 05:32	GRASS VALLEY	10/11/19 16:46
BRUNSWICK 1110	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 05:40	GRASS VALLEY, NEVADA CITY, OROVILLE	10/11/19 13:50
BRYANT 0401	TIER 2, TIER 3	10/09/2019 23:23	CONCORD, ORINDA	10/11/19 9:37
BUCKS CREEK 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 00:09	OROVILLE, STORRIE	10/11/19 17:00
BUCKS CREEK 1102	TIER 2, TIER 3	10/09/2019 00:10	BELDEN, OROVILLE, QUINCY, STORRIE, TWAIN	10/12/19 11:28
BUCKS CREEK 1103	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 01:08	BIGGS, QUINCY	10/11/19 17:50
BURNS 2101	TIER 3	10/10/2019 00:17	BEN LOMOND, SANTA CRUZ	10/11/19 17:49
BUTTE 1105	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 01:08	CHICO	10/11/19 11:48
CAL WATER 1102	TIER 2, PARTIALLY OUTSIDE HFTD	10/10/2019 09:58	BAKERSFIELD	10/11/19 15:20
CALAVERAS CEMENT 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 15:45	ANGELS CAMP, COPPEROPOLIS, GLENCOE, MOKELUMNE HILL, MOUNTAIN RANCH, RAIL ROAD FLAT, SAN ANDREAS, VALLEY SPRINGS	10/11/19 17:53
CALISTOGA 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 01:48	CALISTOGA, NAPA, RUTHERFORD, SANTA ROSA	10/11/19 21:48
CALISTOGA 1102	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 01:02	CALISTOGA, SAINT HELENA	10/11/19 15:54

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time
CALPELLA 1101*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 02:33	CALPELLA, POINT ARENA, POTTER VALLEY, REDWOOD VALLEY, UKIAH, WILLITS	10/11/19 7:35
CAMP EVERS 2103*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 23:12	APTOS, SANTA CRUZ, SCOTTS VALLEY, SOQUEL	10/11/19 15:45
CAMP EVERS 2104*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 22:42	BIG SUR, FELTON, MOUNT HERMON, SANTA CRUZ, SCOTTS VALLEY	10/10/19 18:05
CAMP EVERS 2105*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 22:43	BEN LOMOND, BOULDER CREEK, FELTON, LOS GATOS, MOUNT HERMON, SCOTTS VALLEY	10/11/19 22:17
CAMP EVERS 2106*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 22:43	FELTON, LOS GATOS, MOUNT HERMON, REDWOOD ESTATES, SANTA CRUZ, SCOTTS VALLEY, SOQUEL	10/11/19 17:10
CARLOTTA 1121	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:02	CARLOTTA, FERNDALE, FORTUNA, HYDESVILLE	10/10/19 1:52
CASTRO VALLEY 1106*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 23:01	CASTRO VALLEY, HAYWARD	10/10/19 22:04
CASTRO VALLEY 1108*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 23:10	CASTRO VALLEY, HAYWARD, SAN LEANDRO	10/11/19 11:46
CASTRO VALLEY 1111	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 23:36	CASTRO VALLEY, HAYWARD	10/10/19 20:52
CEDAR CREEK 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 01:15	BELLA VISTA, BIG BEND, BURNEY, HAT CREEK, MONTGOMERY CREEK, OAK RUN, REDDING, ROUND MOUNTAIN	10/12/19 11:33
CHALLENGE 1101	TIER 2, TIER 3	10/09/2019 02:31	CHALLENGE, CLIPPER MILLS, FORBESTOWN, OROVILLE, STRAWBERRY VALLEY	10/12/19 14:05
CHALLENGE 1102	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 02:31	BROWNSVILLE, CHALLENGE, DOBBINS, FORBESTOWN, OROVILLE	10/12/19 9:01

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time
CLARK ROAD 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:59	OROVILLE	10/11/19 12:24
CLARK ROAD 1102	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 02:59	CHICO, OROVILLE, PALERMO, PARADISE	10/11/19 13:55
CLARKSVILLE 2104	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 00:34	EL DORADO HILLS, RESCUE, SHINGLE SPRINGS	10/10/19 18:58
CLARKSVILLE 2109	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 00:37	EL DORADO HILLS, EL DORADO, OREGON HOUSE, RESCUE	10/10/19 17:06
CLARKSVILLE 2110	NON HFTD	10/09/2019 00:43	EL DORADO HILLS	10/10/19 17:07
CLEAR LAKE 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 02:30	FINLEY, KELSEYVILLE, LAKEPORT	10/11/19 15:01
CLEAR LAKE 1102	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:31	FINLEY, KELSEYVILLE, LAKEPORT, MIDDLETOWN	10/11/19 11:24
CLOVERDALE 1102	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:51	CLOVERDALE, CROCKETT, GEYSERVILLE, HEALDSBURG, HOPLAND	10/11/19 12:00
COLUMBIA HILL 1101	TIER 2, TIER 3	10/09/2019 02:34	BROOKS, CAMPTONVILLE, GRASS VALLEY, NEVADA CITY, NORTH SAN JUAN, PENN VALLEY	10/12/19 10:11
CORNING 1101*	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:13	CORNING, COTTONWOOD, FLOURNOY, PASKENTA, RED BLUFF	10/11/19 15:55
CORNING 1102*	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:10	CORNING, FLOURNOY, PASKENTA, RED BLUFF	10/11/19 17:51
CORONA 1101	NON HFTD	10/09/2019 02:46	PETALUMA	10/9/19 11:19
CORONA 1103	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:37	PENNGROVE, PETALUMA	10/10/19 16:37
CORTINA 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 01:03	ARBUCKLE, WILLIAMS	10/10/19 16:26
COTTONWOOD 1101*	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:37	COTTONWOOD, RED BLUFF	10/11/19 16:22

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time
COTTONWOOD 1102*	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:24	ANDERSON, COTTONWOOD, IGO, REDDING	10/11/19 13:48
COTTONWOOD 1103*	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:28	COTTONWOOD, RED BLUFF	10/11/19 15:32
CURTIS 1701	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 15:39	SONORA, STANDARD	10/10/19 16:23
CURTIS 1702	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 15:35	COLUMBIA, PINECREST, SONORA, SOULSBYVILLE, TUOLUMNE, TWAIN HARTE	10/11/19 11:25
CURTIS 1703	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 15:28	BIG OAK FLAT, COULTERVILLE, GROVELAND, JAMESTOWN, SONORA, TUOLUMNE, YOSEMITE NATIONAL PARK	10/11/19 17:16
CURTIS 1704	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 15:40	COLUMBIA, OAKDALE, SONORA, STANDARD, TWAIN HARTE	10/11/19 15:29
CURTIS 1705	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 15:23	GROVELAND, JAMESTOWN, RIVERBANK, SONORA, SOULSBYVILLE, TUOLUMNE, TWAIN HARTE	10/11/19 15:50
DAIRYVILLE 1101	NON HFTD	10/09/2019 01:33	CORNING, LOS MOLINOS, RED BLUFF	10/10/19 20:08
DEL MAR 2109	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:22	AUBURN, LINCOLN, LOOMIS, ROCKLIN	10/10/19 16:24
DESCHUTES 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:08	MILLVILLE, OAK RUN, PALO CEDRO, REDDING, SHINGLETOWN, WHITMORE	10/11/19 14:01
DESCHUTES 1104	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 03:14	ANDERSON, BELLA VISTA, MILLVILLE, PALO CEDRO, REDDING	10/11/19 8:29
DIAMOND SPRINGS 1103*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 00:41	EL DORADO, PLACERVILLE	10/11/19 17:50
DIAMOND SPRINGS 1104*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 01:15	DIAMOND SPRINGS, EL DORADO, PLACERVILLE	10/10/19 23:20

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time
DIAMOND SPRINGS 1105	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 02:17	DIAMOND SPRINGS, EL DORADO, PLACERVILLE, SHINGLE SPRINGS	10/11/19 14:25
DIAMOND SPRINGS 1106*	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:49	DIAMOND SPRINGS, EL DORADO, PLACERVILLE	10/11/19 15:15
DIAMOND SPRINGS 1107*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 00:51	PLACERVILLE, SHINGLE SPRINGS	10/10/19 18:38
DOBBINS 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:40	BROWNS VALLEY, BROWNSVILLE, CAMPTONVILLE, DOBBINS, DOWNIEVILLE, GREENWOOD, MARYSVILLE, OREGON HOUSE, WHEATLAND	10/11/19 15:00
DRUM 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:22	ALTA, EMIGRANT GAP, MEADOW VISTA, NEVADA CITY	10/11/19 18:13
DUNBAR 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 01:12	GLEN ELLEN, KENWOOD, SANTA ROSA, SONOMA	10/11/19 17:56
DUNBAR 1102	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 01:33	BOYES HOT SPRINGS, ELDRIDGE, GLEN ELLEN, SANTA ROSA, SONOMA	10/11/19 21:42
DUNBAR 1103	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 01:56	GLEN ELLEN, SONOMA	10/11/19 15:08
EAST MARYSVILLE 1108	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:20	BROWNS VALLEY, MARYSVILLE, PENN VALLEY, YUBA CITY	10/10/19 15:34
EDES 1112	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 22:33	OAKLAND	10/10/19 20:05
EEL RIVER 1102	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:25	EUREKA, FERNDALE, FIELDS LANDING, FORTUNA, LOLETA, RIO DELL	10/10/19 2:00
EEL RIVER 1103	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:19	FERNDALE, FORTUNA	10/10/19 1:46
EL CERRITO G 1105	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 22:50	ALBANY, BERKELEY, EL CERRITO, ORINDA, RICHMOND, SAN PABLO	10/10/19 18:59

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time
EL DORADO PH 2101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:52	CAMINO, ECHO LAKE, GEORGETOWN, GRIZZLY FLATS, KYBURZ, PLACERVILLE, POLLOCK PINES, SOMERSET, TWIN BRIDGES	10/11/19 23:56
EL DORADO PH 2102	TIER 3	10/09/2019 03:55	CAMINO, POLLOCK PINES	10/11/19 13:35
ELECTRA 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:40	JACKSON, PINE GROVE	10/11/19 10:33
ELECTRA 1102	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:37	FIDDLETOWN, JACKSON, MOKELUMNE HILL	10/10/19 18:35
ELK CREEK 1101*	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:32	DURHAM, ELK CREEK, ORLAND, STONYFORD, WILLIAMS, WILLOWS	10/12/19 10:59
EUREKA A 1103	NON HFTD	10/09/2019 08:03	EUREKA	10/9/19 23:48
EUREKA A 1106	NON HFTD	10/09/2019 08:03	EUREKA, FORTUNA	10/9/19 23:45
EUREKA A 1107	NON HFTD	10/09/2019 08:04	EUREKA	10/9/19 23:47
EUREKA E 1101	NON HFTD	10/09/2019 03:45	EUREKA	10/9/19 23:12
EUREKA E 1104	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 03:45	EUREKA	10/10/19 0:11
EUREKA E 1105	NON HFTD	10/09/2019 03:46	EUREKA	10/9/19 23:09
FAIRHAVEN 1103	NON HFTD	10/09/2019 08:31	ARCATA, SAMOA	10/9/19 22:26
FELTON 0401	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/10/2019 11:24	BEN LOMOND, FELTON, SANTA CRUZ	10/10/19 16:46
FITCH MOUNTAIN 1113	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:28	GEYSERVILLE, GUERNEVILLE, HEALDSBURG	10/12/19 14:45
FLINT 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:26	AUBURN	10/10/19 20:21
FLINT 1102	TIER 2	10/09/2019 00:28	AUBURN	10/9/19 18:03
FORESTHILL 1101	TIER 2, TIER 3	10/09/2019 04:20	AUBURN, FOLSOM, FORESTHILL, OAKDALE	10/11/19 17:42

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time
FORESTHILL 1102	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 04:21	AUBURN, FORESTHILL	10/11/19 13:54
FORT SEWARD 1121	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:09	ALDERPOINT, GARBERVILLE, ZENIA	10/10/19 4:14
FORT SEWARD 1122	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:14	ALDERPOINT, BLOCKSBURG, GARBERVILLE, ZENIA	10/10/19 4:03
FREMONT 1104*	TIER 2, PARTIALLY OUTSIDE HFTD	10/10/2019 00:53	FREMONT	10/10/19 16:05
FRENCH GULCH 1101	TIER 2	10/09/2019 01:31	FRENCH GULCH	10/11/19 15:40
FRENCH GULCH 1102	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 01:30	FRENCH GULCH, REDDING, WHISKEYTOWN	10/11/19 15:59
FROGTOWN 1701	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 15:24	ANGELS CAMP, ARNOLD, AVERY, DOUGLAS FLAT, MOUNTAIN RANCH, MURPHYS, VALLECITO	10/11/19 12:11
FROGTOWN 1702	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 15:37	ALTAVILLE, ANGELS CAMP, ARNOLD, CLEMENTS, COPPEROPOLIS, DOUGLAS FLAT, FARMINGTON, GUSTINE, MURPHYS, SAN ANDREAS, VALLECITO, VALLEY SPRINGS	10/11/19 20:50
FRUITLAND 1141	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:03	MYERS FLAT, PHILLIPSVILLE, REDCREST, REDWAY, WEOTT	10/10/19 3:09
FRUITLAND 1142	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:07	BLOCKSBURG, MIRANDA, MYERS FLAT, PHILLIPSVILLE, REDCREST, WEOTT	10/10/19 4:24
FULTON 1102*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 02:15	HEALDSBURG, SANTA ROSA, WINDSOR	10/11/19 15:38
FULTON 1107*	TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:50	FULTON, SANTA ROSA, WINDSOR	10/11/19 10:58

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time

GARBERVILLE 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:12	ALDERPOINT, GARBERVILLE, LAYTONVILLE, LEGGETT, PIERCY, REDWAY, WESTPORT, WHITETHORN, ZENIA	10/10/19 5:56
GARBERVILLE 1102	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:23	GARBERVILLE, HONEYDEW, LOOMIS, PETROLIA, PHILLIPSVILLE, REDWAY, WHITETHORN	10/10/19 5:16
GARBERVILLE 1103	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:28	GARBERVILLE	10/10/19 3:32
GERBER 1101	NON HFTD	10/09/2019 01:26	CORNING, GERBER, RED BLUFF, TEHAMA	10/10/19 18:49
GERBER 1102	NON HFTD	10/09/2019 01:27	CORNING, GERBER, PROBERTA, RED BLUFF, REDDING	10/10/19 18:58
GEYSERVILLE 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 03:12	ANNAPOLIS, CLOVERDALE, GEYSERVILLE, HEALDSBURG	10/11/19 21:05
GEYSERVILLE 1102	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 02:57	CLOVERDALE, GEYSERVILLE, HEALDSBURG	10/11/19 19:55
GIRVAN 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:18	ANDERSON, COTTONWOOD, IGO, REDDING	10/11/19 11:51
GIRVAN 1102	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 03:10	REDDING, SHASTA	10/11/19 12:48
GLENN 1101*	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 01:08	ORLAND	10/10/19 19:20
GRASS VALLEY 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 02:44	GRASS VALLEY	10/11/19 8:33
GRASS VALLEY 1102	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:49	GRASS VALLEY	10/11/19 8:05
GRASS VALLEY 1103	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:52	GRASS VALLEY, PENN VALLEY, ROUGH AND READY	10/11/19 18:54
GREEN VALLEY 2101*	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 22:45	GILROY, WATSONVILLE	10/11/19 10:40
HALF MOON BAY 1101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 23:22	EL GRANADA, HALF MOON BAY, MOSS BEACH, REDWOOD CITY, SAN MATEO	10/10/19 18:08

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time

HALF MOON BAY 1102	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 23:31	EL GRANADA, HALF MOON BAY, MONTARA, MOSS BEACH, PACIFICA	10/10/19 18:36
HALF MOON BAY 1103	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 23:31	DAVENPORT, EL GRANADA, HALF MOON BAY, LA HONDA, LOMA MAR, PESCADERO, REDWOOD CITY, SAN GREGORIO	10/11/19 16:39
HALSEY 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 04:37	APPLEGATE, AUBURN, COLFAX, DUTCH FLAT, MEADOW VISTA	10/11/19 15:00
HALSEY 1102	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 04:43	ALTA, APPLEGATE, AUBURN, COLFAX, MEADOW VISTA, SODA SPRINGS, STOCKTON	10/11/19 8:41
HARRIS 1108	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:34	ARCATA, CUTTEN, EUREKA, MCKINLEYVILLE	10/10/19 1:58
HARRIS 1109	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 02:42	ARCATA, EUREKA, KNEELAND	10/10/19 2:02
HARTLEY 1101	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 03:06	LAKEPORT, NICE, UPPER LAKE	10/11/19 12:42
HARTLEY 1102	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 03:03	COBB, LAKEPORT	10/11/19 16:26
HICKS 2101	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 23:58	SAN JOSE	10/10/19 17:59
HIGGINS 1103	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:11	AUBURN, GRASS VALLEY	10/11/19 15:26
HIGGINS 1104	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:15	GRASS VALLEY	10/11/19 12:21
HIGGINS 1107	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:19	AUBURN, GRASS VALLEY, NEVADA CITY	10/11/19 9:13
HIGGINS 1109	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:22	AUBURN, GRASS VALLEY, PENN VALLEY	10/11/19 15:43
HIGGINS 1110	TIER 2, PARTIALLY OUTSIDE HFTD	10/09/2019 00:25	AUBURN, COLFAX, GRASS VALLEY, MEADOW VISTA	10/11/19 13:08
HIGHLANDS 1102	TIER 2, TIER 3, PARTIALLY OUTSIDE HFTD	10/09/2019 02:13	CLEARLAKE OAKS, CLEARLAKE	10/11/19 8:12

Table 1-1. Distribution (Continued)

Circuit	HFTD Tier(s)	Start Date and Time	Key Communities	Restoration Date and Time