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THE OUTLOOK FOR ENERGY AND MINERALS MARKETS IN THE 116TH CONGRESS

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED SIXTEENTH CONGRESS

FIRST SESSION

FEBRUARY 5, 2019

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THE OUTLOOK FOR ENERGY AND MINERALS MARKETS IN THE 116TH CONGRESS

TUESDAY, FEBRUARY 5, 2019

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The Committee met, pursuant to notice, at 9:51 a.m. in Room SD–366, Dirksen Senate Office Building, Hon. Lisa Murkowski, Chairman of the Committee, presiding.

OPENING STATEMENT OF HON. LISA MURKOWSKI, U.S. SENATOR FROM ALASKA

The CHAIRMAN. Good morning, everyone. The Committee will come to order.

This is our first hearing for the 116th Congress. It is good to be back at work. We have had a little bit slower start than we anticipated, but we are making up for it today with both our organizational meeting as well as our first official hearing.

This is an action-packed energy day because we have an opportunity to take a cloture vote on a motion to proceed to our bipartisan lands package. This will happen later this afternoon. So many of you have been working with us on that, and we are really very pleased that we are going to be moving forward with that.

While we wait for a quorum to begin the business meeting here this morning, I want to acknowledge and thank my former Ranking Member, Senator Cantwell, who for the past couple of years has been sitting right here and now she is a couple chairs down. But thank you, Senator Cantwell, for all that you have done as we worked together in this Committee to make good things happen, not the least of which is this lands package that we have been working on and so many other things. We are continuing to work in good faith and good measure on that, but I greatly, greatly appreciate what you have provided.

I would like to recognize my new Ranking Member, Senator Manchin, a long-time friend and colleague from West Virginia. We have had more than a couple of meetings already, going through what the Committee might anticipate for the year ahead and some of the opportunities. I think we both look at this from the perspective of coming from states that are producing states, but we have a lot of challenges within the demographics of our state, working together to address some of those challenges and to advance the opportunities is what we are all about.

I would also like to welcome our new members to the Committee. We have Senator Hyde-Smith who is with us from Mississippi, and

Senator McSally from Arizona. I think we always have an Arizonan on the Committee. It must be a mandatory requirement or something, but we are very pleased to have you with us. I think you will find that you made an excellent choice in selecting the Energy Committee. We are a good committee. We work hard. We work in a bipartisan manner, and it is always good.

Let me just give a little bit of a rundown in terms of what we are dealing with this morning. For the business meeting portion, we need to approve the Committee's funding resolution, ratify Subcommittee assignments and update our rules and our jurisdictional listings. These materials were transmitted to members last week, and copies have been provided.

Our funding resolution in agenda item one authorizes the Committee to make expenditures out of the Senate's contingent fund to pay staff salaries, mailing expenses and other administrative costs. The Rules Committee, which provides the authorization levels, has requested that we report this resolution this week.

With regards to agenda item two, the subcommittee assignments, I welcome our new Chairmen and Ranking Members to their roles. Senator Cassidy is going to be serving as the Chairman of the Energy Subcommittee with Senator Henrich as his Ranking Member. Senator Daines will be back as the Chairman of the National Parks Subcommittee with Senator King as his Ranking Member. Senator Lee is again Chairman of the Public Lands, Forests, and Mining Subcommittee and Senator Wyden will be his counterpart as the Ranking Member. And then finally, Senator McSally will serve as the Chairman of the Water and Power Subcommittee, and Senator Cortez Masto will be her Ranking Member. So, a great opportunity for all of you. I congratulate you on that. We are slightly modifying our jurisdictional listing so that bills relating to outdoor recreation resources are referred to the appropriate subcommittee on a case-by-case basis.

Agenda item three contains certain changes to our Committee rules. As we explained in the materials that were provided, we are lowering the number of members needed for both a working and a reporting requirement. This reflects the decrease in the Committee's membership from 23 members down to 20 members in this Congress.

Additionally, we are clarifying that an amendment filing deadline may be imposed for business meetings, if needed. Typically, we set these deadlines only once or twice a Congress and always in consultation with the Ranking Member.

We are also making a few technical updates to reflect the fact that women actually serve on this Committee.

[Laughter.]

So we went through the language and noted that while we give a lot of support to the hes, maybe we just add an s to that as well, just kind of updating things.

So before we are able to do any business, Senator Manchin, why don't I turn to you for a moment for any opening comments that you might make as we are waiting. Otherwise, once you are done with that if we still do not have a quorum, we will move to our hearing. I know that several members have conflicting obligations here just about ten o'clock.

Senator Manchin.

STATEMENT OF HON. JOE MANCHIN III, U.S. SENATOR FROM WEST VIRGINIA

Senator MANCHIN. Well, Chairman Murkowski, first of all, it is a pleasure to be with you in this position. Also, I want to thank Senator Cantwell for her leadership in what she has done and how hard she has worked and gotten the land bill ready to go. We are going to carry the ball over the goal line, if we can, today—starting today, anyway.

But anyway, it is an honor to sit next to you. We are friends. We have been friends for a long time, and this is our first full Committee hearing in the Congress.

I am honored to serve as Ranking Member of the Committee which has been around for 42 years as of—yesterday was its birthday, I believe. Right, Sam?

I look forward to working with you, Madam Chairman, to tackle the biggest energy and natural resource questions facing our country, as well as beginning discussions on how we, as a Committee, can contribute pragmatic solutions to the climate challenges facing our country and the world.

I would also like to thank Senators Wyden, King, and Cortez Masto for continuing to serve as Ranking Members on the Public Lands, Parks, and Water and Power Subcommittees. Also, I am glad to turn over the Ranking Membership of the Energy Subcommittee to Senator Heinrich and thank him for agreeing to do so.

I want to take a moment to briefly touch on one rule change before us today which allows for filing deadlines to be set for amendments. I want to be clear that my understanding is that this is to provide all of our members more notice and time to consider what they will be asked to vote on, rather than to limit the ability of our members to offer amendments. We have drafted this to encourage collaboration and maintain the most flexibility.

I am excited to welcome those witnesses here today with Chairman Murkowski and look forward to the conversation.

In 2016, West Virginia, my little state, ranked fifth among the states in total energy production, according to the EIA. Our state has also consistently exported more electricity than we consume. We are a net producer. It is for that reason other states depend on us for reliable electric generation as well as coal and natural gas production. In fact, West Virginia is the seventh largest producer of marketable natural gas in the nation. Our underground gas storage capacity accounts for almost six percent of the nation's total capacity, which is critical in the winter months for the northeast.

West Virginia, along with its neighbors, also has the historic opportunity to develop an Appalachian Storage Hub. This innovative regional storage and distribution hub would attract manufacturing investment, create jobs and reduce the rejection rate of natural gas liquids to the ethane, thereby reducing greenhouse gas emissions.

West Virginia also accounts for 11 percent of the nation's coal production and is among the top three states in the amount of recoverable coal reserves at producing mines. Despite coal production declines around the country, Appalachian coal production increased for the second year in a row based largely on growth in coal exports to India, the Ukraine, Brazil and other nations.

Beyond my state's leadership on energy production, I know all of West Virginia is committed to solving the climate crisis. The impacts of climate change are felt in every economy in every community across the world, and that includes my State of West Virginia.

I have never met a West Virginian who wants to drink dirty water or breathe dirty air. The urgent need to clean up our climate is felt by everyone, and there is no reason rural America cannot be part of the cleaner energy solutions that we are working toward. We must work together to solve the problem and act now to lead the world in commercialization of carbon-reducing energy technology that keeps energy generation resources cost competitive and reliable, 24/7.

This is especially important during events like last week's polar vortex, where I know communities around the country are grateful for the energy supply and reliability that West Virginia provides.

Last week's brutal cold provided another test case for how our electricity grid is often stressed and changing. On Wednesday and Thursday regional grid operators for the Northeast—which is PJM, and Midwest—which is MISO, put emergency procedures in place. PJM serves approximately 65 million customers and includes my home State of West Virginia. On Thursday morning, PJM had one of its top 10 winter peak demand days in the last five years.

While the system performed well, rising natural gas demand made it economical to bring on coal to keep the lights on and homes warm, and coal will continue to be a critical part of the fuel mix in extreme weather situations like this, even in states with aggressive clean energy goals. If it gets cold, we are still going to need to work together.

Events like the polar vortex will continue to happen, continuing to underscore the importance of reliable energy; but it is clear as day that the United States does not lead in developing the technologies that will incentivize China and India to burn coal and natural gas in a cleaner way. It will not matter how much we do here.

In 2040, the International Energy Agency predicts that coal will make up about 51 percent of China's electric mix. For India, it could be up to 57 percent.

That is why I am encouraged to see leaders like Bill Gates, who is putting his money where his mouth is, in the clean energy race, particularly with respect to advanced nuclear technology.

Climate change is real and communities across our nation have suffered the destructive effects associated with it. In 2016, our little state was devastated by a flood that took the lives of 23 West Virginians. In the last four years, I have asked the White House for emergency funding six times due to flooding.

There is no silver bullet. And I have spoken with Chairman Murkowski. I look forward to innovation discussions in expected climate hearings to see how this Committee can contribute to the pragmatic solutions that will work for every American.

With that, I look forward to hearing from our witnesses today.

The CHAIRMAN. Wonderful, thank you.

Well it appears, quite clearly, that we are not going to have a quorum. I think this is what happens when you get back to work, and we have committee hearings that have just been stacked up. I know that there are three others that I am supposed to be at, but this is the one that I am going to be at.

So let's go ahead and acknowledge that our business meeting will have to be held off the Floor at some later point in time.

Senator Cantwell.

STATEMENT OF HON. MARIA CANTWELL, U.S. SENATOR FROM WASHINGTON

Senator CANTWELL. Madam Chairman, thank you so much for your comments earlier. I certainly want to recognize the great working relationship that existed between us and the great work in passing both the energy bill out of the Senate and our determination to get our House colleagues to understand the importance of cybersecurity, energy efficiency, and so many other things. I know that work will continue, and I am certainly very excited that we are apparently going to get to the lands package and finally get that over the transom.

I did want to mention on the rule change—first I also want to say congratulations to Senator Manchin. I am looking forward to working with him and all of his interests, particularly in the areas of grid reliability and modernization, because I think there is so much that our nation can do in that regard. And so, I am very happy with your new role on this Committee.

I definitely plan to, obviously, with the State of Washington's immense interest in the Committee, continue to be an active member. I am really looking forward to working with both of you in that capacity.

On the rule five change, I was just trying to seek a little clarification. That is, I think we had a 24-hour notice on amendments. And so, I just want some transparency on—what is this now? Is it—will it be determined, you know, on a case-by-case basis about the filing deadline or will it—I am just trying to get a sense of what that actually means?

The CHAIRMAN. Well, Senator Cantwell, we will have staff also speak to us, but it is my understanding that there was a discussion about whether or not we wanted this 24 hours to be hard and fast in terms of a hard and fast deadline or more of a guideline, if you will. And so, that was why the language before the Committee to impose the filing deadline is softened with "as warranted and in consultation with the Ranking Member." I think that was much of the back and forth and either Kellie or Sam, if you want to speak to that?

Ms. DONNELLY. We did not have a specific rule in the rules for the filing deadline. The Committee has had a longstanding practice of trying to work things out on a unanimous case basis between joint staff.

And so, only a couple of times in Congress have we had to impose a deadline. This is just a signal in the rules that a deadline can be imposed, if warranted, but in consultation with the Ranking Member. So it would be done on a case-by-case basis and the instructions would go out three days in advance, along with the business meeting notice, so that everybody has appropriate time.

Mr. FOWLER. And I would simply add that more than two-thirds of the standing committees of the Senate do have filing deadlines and none of them are the same, but this is probably one of the most flexible, most lenient deadlines.

Senator CANTWELL. Well, since we don't have an official adoption of this today, I guess I would hope that we could think about, you know, how we ensure transparency because you don't want for one week it to be 24 hours, the next week it be one hour before the business meeting and another time it's, you know, different.

I think the fact that we had a standard was good. But, I am all for exemptions to the standard because I know there have been moments here in the Committee where we have come up with a brilliant idea to get out of a jam and wanted to offer the amendment right then and there. And so, I am not opposed to having that safeguard, if you will, to get through that process. But I am more interested in what kind of standard we can establish so people know and can plan for it as opposed to it being different from time to time. And then that way, members don't really plan accordingly.

So I guess that all supposes that we are going to mark up lots of legislation which I hope we are going to continue——

The CHAIRMAN. I hope we are going to.

[Laughter.]

Senator CANTWELL. I hope we are going to continue to mark up things.

I don't know if the other committees have—I think you can waive the rule, is that right, Sam?

Mr. FOWLER. Yes, and I would just point out that the Committee has never had a filing deadline in the rules before. Various chairmen and ranking members have agreed to encourage members to file by a certain deadline which has never been enforceable. This simply gives the Committee a basis in the rules to do what the chairs and ranking members have been trying to do on an informal basis in the past.

The CHAIRMAN. Fair enough, and I hear your comments.

Senator CANTWELL. Food for thought.

The CHAIRMAN. Yes, I hear your comments, Senator Cantwell, and I appreciate that. I think it just speaks, once again, to the very collaborative nature of this Committee that we really have not had an issue with this, that typically things are worked out between the staffs. And I think that is a real testament to their efforts as well, but consider that. Thank you.

Well, let's go ahead and begin our first official hearing then. I really cannot think of a better way to set the stage here for this Congress than to welcome this panel of witnesses to look at the outlook for the energy and mineral markets.

Whether we realize it or not, energy and minerals fuel our 21st century economy and our standard of living. Access to energy and minerals, or perhaps lack thereof, can impact everything from health care to poverty levels, to defense readiness, to the strength of our manufacturing center.

And the markets for energy and minerals are rapidly changing. In just the past decade we have seen a dramatic increase in domestic energy production with a corresponding decrease in energy imports. Our domestic demand has remained relatively flat, but world demand has risen. So it is a good thing that we are now the world's largest producer of oil and natural gas, with renewables growing rapidly as well.

This remarkable shift has been a game-changer. We have realized substantial economic benefits here at home while also giving us options to help our allies to achieve a greater level of energy security. But we also face potential challenges, including questions about the reliability and resiliency of our nation's grid system as we lose baseload coal and nuclear.

In contrast to the energy sector, our nation, in my view, is headed the wrong way on mineral imports. In 2017, we imported 50 percent of 50 mineral commodities, including 100 percent of 21 minerals. This is a dangerous trend. It is really our Achilles heel that serves to empower and enrich other nations, while costing us jobs and international competitiveness. Over the past several years, our Committee has sought to call attention to our reliance on foreign nations for our minerals. The Administration has taken several important steps, but we must complement their actions with our own legislative actions.

We have a great panel with us this morning to help us understand these market trends. Our witnesses are testifying on behalf of the Energy Information Administration (EIA), the ClearView Energy Partners, the R Street Institute, Bloomberg New Energy Finance and Benchmark Mineral Intelligence. We appreciate your willingness to share your expertise with the Committee.

Senator Manchin, you had provided your opening comments. I don't know if you want to add anything at this point in time before I begin their introductions and have them—let's go right ahead.

We are joined this morning, as I mentioned, from the U.S. Energy Information Administration by Dr. Linda Capuano. It is nice to have you back before the Committee. Mr. Kevin Book has been before the Energy Committee multiple times. He is with ClearView Energy Partners. Mr. Travis Kavulla is the Director of Energy and Environmental Policy at R Street Institute. Simon Moores is the Managing Director for Benchmark Mineral Intelligence, and Mr. Ethan Zindler, who has also been before this Committee several times, is Head of the Americas for Bloomberg New Energy Finance. Welcome to all of you.

We ask that you provide us your comments and try to keep them to about five minutes. Your full statements will be included as part of the record.

Again, we appreciate you being here and helping kick off this very informative session for the Energy Committee.

Dr. Capuano.

STATEMENT OF HON. LINDA CAPUANO, ADMINISTRATOR, U.S. ENERGY INFORMATION ADMINISTRATION, U.S. DEPARTMENT OF ENERGY

Dr. CAPUANO. Chairman Murkowski, Ranking Member Manchin and members of the Committee, I appreciate the opportunity to appear before you today to provide testimony on U.S. energy.

This is a transformational time for the United States energy industry. After decades of importing more energy than it exports, EIA now forecasts that the United States will become a net energy exporter in 2020. The crossover to net exporter occurs as crude production increases and domestic consumption of petroleum products decreases. The U.S. produced almost 11 million barrels per day of crude oil in 2018, and EIA expects the U.S. crude oil production will remain greater than 14 million barrels per day through 2040. Favorable geology and recent technological and operational improvements have allowed petroleum liquids production from tight rock formations within the Permian region in Texas and New Mexico to grow to an average of 3.5 million barrels per day in 2018, compared with 2.5 in 2017.

The United States is now the world's largest producer of crude oil, surpassing Saudi Arabia and Russia. Our natural gas plant liquids production set an all-time high of 4.4 million barrels per day in 2018. The combined increases in crude oil and NGPL output, coupled with our refining capacity, has led the United States to become a major exporter of petroleum products. By the fourth quarter of 2020, EIA expects exports of petroleum products from the United States to exceed imports by an average of 0.9 million barrels per day.

The steady increase in U.S. crude oil production contributes to a relatively steady oil price of $73 to $74 per barrel until 2022, after which crude oil prices are projected to steadily rise to $108 per barrel in 2050.

U.S. liquid fuels net imports, which include crude oil and petroleum products, have declined steadily and we estimate they average 1.2 million barrels per day in the fourth quarter of 2018. This is less than half of the volume the United States imported last year; however, while imports have declined, the United States will continue to import crude oil.

Similar developments in domestic shale natural gas resources have enabled the United States to emerge as a net exporter of natural gas. In 2017, total natural gas exports from the United States exceeded imports and natural gas production reached an all-time high of 30 trillion cubic feet in 2018. In the longer-term, EIA projects that natural gas production will initially grow by seven percent per year, then slow to grow less than one percent per year after 2020. As a result, net U.S. exports will continue to grow as liquefied natural gas and pipeline exports increase.

Abundant natural gas supplies and the resulting relatively low natural gas prices have led to other changes. Despite total U.S. electricity demand remaining relatively flat over the past decade, natural gas displaced less economically competitive sources of electric power generation to become the largest share of electric power generation in 2016.

Wind and solar capacity and generation also reached all-time highs in 2018. And under current policies and regulations, EIA's Reference case in our just-released Annual Energy Outlook for 2019 projects that renewable sources will surpass nuclear in 2019 and coal in 2025. As a result, EIA projects that carbon dioxide emissions will remain about two percent below the 2020 level across the projection period to 2050.

Relative to consumption, the AEO2019 Reference case assumes 1.9 percent compound annual growth rate for real U.S. gross domestic product through 2050 and total energy consumption grows by 0.2 percent per year through 2050. Industrial consumption grows the fastest, taking advantage of relatively low natural gas prices, while electricity power consumption increases at a slower rate due to efficiency improvements. EIA projects that residential and commercial buildings will maintain relatively flat energy consumption and growth, and demographic shifts offset policy gains.

EIA projects that the U.S. transportation sector will see a decrease in consumption through the mid–'30s as fuel economy increase offsets growth in vehicle miles traveled. However, as current regulations requiring additional efficiency increases expire after 2027, we project that motor gasoline consumption will start rising again, leading to total transportation sector consumption increases past 2040.

And so, this is an exciting and transformational time for the United States' energy industry as world energy markets adjust to the United States becoming a major global supplier and exporter for the years to come.

[The prepared statement of Dr. Capuano follows:]

Statement of Linda Capuano
Administrator
U.S. Energy Information Administration
U.S. Department of Energy
Before the
Energy and Natural Resources Committee
United States Senate
February 5, 2019

Chairman Murkowski, Ranking Member Manchin, and Members of the Committee, I appreciate the opportunity to appear before you today to provide testimony on U.S. energy.

This is a transformational time for the United States energy industry. After decades of the United States importing more energy than it exports, EIA now forecasts that our country will become a net energy exporter in 2020. The crossover to being a net exporter occurs as crude oil production continues to increase. The United States produced almost 11 million barrels per day (b/d) of crude oil in 2018, exceeding our previous 1970 record of 9.6 million barrels. EIA expects that U.S. crude oil production will continue to set annual records until 2030 and will remain greater than 14.0 million b/d through 2040.

The U.S. oil and natural gas industry, consisting of natural gas, crude oil, and other liquids production, has seen impressive growth as hydraulic fracturing and horizontal drilling have led to economically competitive development of shale resources that were previously uneconomical to develop. Favorable geology and recent technological and operational improvements have allowed petroleum liquids production from tight rock formations within the Permian region in Texas and New Mexico to grow to an average of 3.5 million b/d in 2018, compared with 2.5 million b/d in 2017. Nearly all of the growth in U.S. crude oil production in 2018 came from tight oil formations, and tight oil production accounted for 58% of total crude oil production in 2018 compared with 53% in 2017.

The United States is now the world's largest producer of crude oil, surpassing Saudi Arabia and Russia in 2018. Our natural gas plant liquids (NGPL) production, a component of the total liquid fuels production, set an all-time high of 4.4 million b/d in 2018. The combined increases in crude oil and NGPL output, coupled with our sophisticated and plentiful refining capacity, have led the United States to become a major exporter of petroleum products. By the fourth quarter of 2020, EIA expects exports of petroleum products from the United States to exceed imports by an average of 0.9 million b/d.

The steady increase in U.S. crude oil production contributes to a relatively steady Brent oil price of $73 to $74 per barrel (2018 dollars) until 2022, after which crude oil prices are projected to steadily rise to $108 per barrel in 2050.

U.S. net imports of liquid fuels, which include crude oil and petroleum products, have declined steadily since 2007, and we estimate that they averaged 1.2 million b/d in the fourth quarter of 2018. This amount is less than half of the volume the United States imported just one year ago, when our net imports averaged 2.7 million b/d during the fourth quarter of 2017. However, although imports have declined, the United States will continue to import crude oil. This robust trade in crude oil and refined products indicates the United States is becoming a globally significant "merchant refiner."

Similar developments in domestic shale natural gas resources have enabled the United States to become a net exporter of natural gas. In 2017, total natural gas exports from the United States exceeded imports for the first time since the 1950s. In 2018, U.S. dry natural gas production reached an all-time high of 30 trillion cubic feet (Tcf). In the long term, EIA projects that natural gas production will initially grow by 7% per year and then slow to less than 1% per year after 2020. As a result, net U.S. natural gas exports will continue to grow as liquefied natural gas (LNG) and pipeline exports increase.

Abundant, domestic natural gas supplies and the resulting relatively low natural gas prices have led to other changes in the U.S. energy landscape. Despite total U.S. electricity demand remaining relatively flat during the past decade, natural gas displaced less economically competitive sources of electric power generation to become the largest share of electric power generation in 2016.

Wind and solar capacity and generation also reached all-time highs in 2018. According to our just-released *Annual Energy Outlook 2019* (AEO2019), under current policies and regulations, EIA's Reference case projects that renewable sources will surpass nuclear in 2020 and coal after 2025. As a result, EIA projects that carbon dioxide (CO2) emissions will remain at least 2% lower than the 2020 level through 2050.

The AEO2019 Reference case assumes a 1.9% compound annual growth rate for real U.S. gross domestic product through 2050 and 0.2% per year growth in total energy consumption through 2050. Industrial consumption of energy grows the fastest, taking advantage of relatively low natural gas prices, while electric power consumption increases at a slower rate as a result of efficiency improvements. EIA projects that residential and commercial buildings will maintain relatively steady energy consumption, as demand growth and demographic shifts offset efficiency gains.

EIA projects that energy consumption in the U.S. transportation sector will decrease through the mid-2030s as fuel economy increases offset growth in vehicle miles traveled. However, as current regulations requiring additional efficiency increases expire after 2027, we project that motor gasoline consumption will start to rise again, leading to total transportation sector consumption increases after 2040.

Short-term energy trend highlights

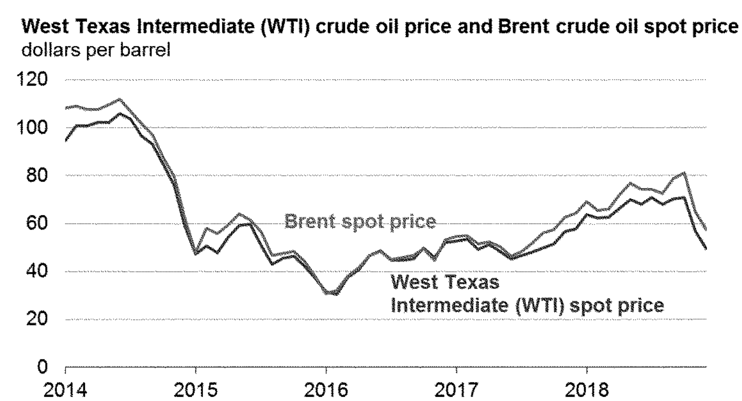
Energy commodity prices saw annual increases in 2018 compared with 2017, however commodity prices ended 2018 lower than they began the year

Crude oil prices had been increasing for most of 2018 in response to the increased potential for supply constraints and declining global petroleum inventories throughout much of 2017. The potential supply constraints include the declining Iranian exports as a result U.S. sanctions targeting its oil sector, declining production in Venezuela, and periodic disruptions from other producers including Libya and Nigeria.

Brent crude oil reached a four-year high of $86 per barrel (b) on October 4, 2018. However, several factors contributed to the subsequent sharp fall in crude oil prices. Crude oil production in the United States, Russia, and Saudi Arabia increased to or near record highs. Concerns about slowing global economic growth and its impact on oil demand also contributed to recent declines in crude oil prices. Waivers granted to certain countries that import Iranian crude oil also helped to ease concerns about crude oil availability in the near term. Crude oil prices ended 2018 lower than where they started at the beginning of the year for the first time since 2015.

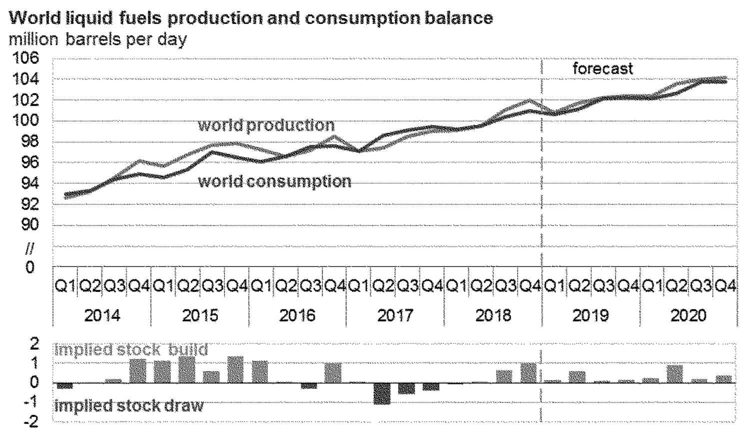
The West Texas Intermediate (WTI) crude oil prices ended 2018 lower than $50/b despite having increased to almost $71/b in July 2018, the highest average monthly price for WTI since late 2014. Prices have remained around $50/b thus far in 2019 (Figure 1).

Figure 1. Brent and West Texas Intermediate (WTI) spot prices



EIA expects that, in the short term, similar market trends will continue to prevail as global oil production is expected to exceed global consumption in 2019 and 2020; however, the global market is expected to become more balanced in 2019 and 2020 (Figure 2).

Figure 2. Oil supply growth continues to slightly outpace consumption growth in 2019 and 2020



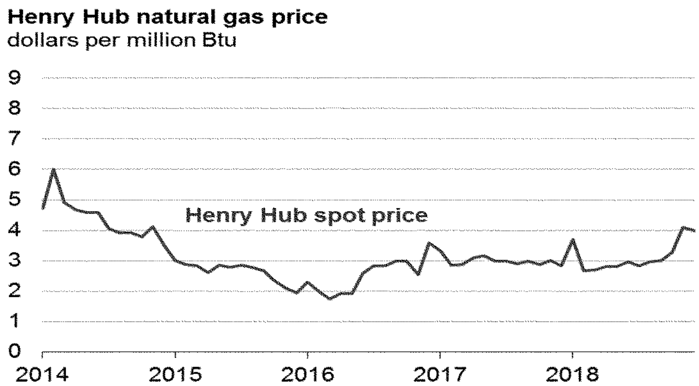
Source: Short-Term Energy Outlook, January 2019

Henry Hub natural gas prices remained lower than an average of $3 per million British thermal units (MMBtu) in seven months in 2018 and averaged $3.15 per MMBtu for the year. Spot natural gas prices remained lower than$3 per MMBtu for much of the year as domestic production reached new record highs, which more than offset the effects of record levels of consumption and exports (Figure 3).

EIA estimates that coal production fell by about 20 million short tons (MMst) in 2018, despite a 19 MMst increase in coal exports. Average coal prices were $2.07 per MMBtu in 2018 and are expected to remain at about that level in 2019 and 2020. Low natural gas prices have primarily contributed to reduced demand for coal in the United States, with coal accounting for 28% of total U.S. electricity generation in 2018, compared with 45% in 2010. Natural gas accounted for 35% of total U.S. electricity generation, compared with 24% in 2010.

Residential sector retail electricity prices averaged 12.9 cents/kilowatthour in 2018, and prices are expected to rise to 13.3 cents/kilowatthour in 2019. Similarly, industrial and commercial electricity prices are expected to rise in 2019.

Figure 3. Despite an uptick in prices at the end of 2018, Henry Hub spot price averaged about $3 per MMBtu



Among renewable sources, hydroelectricity continued to provide the most electricity generation in 2018, with wind generation trailing only slightly behind that of hydroelectricity. EIA expects that wind generation will exceed that of hydroelectricity in 2019. Overall, renewable generation provided 17% of total U.S. electricity generation in 2018.

Long-term energy trend highlights

EIA's *Annual Energy Outlook 2019* (AEO2019), released on January 24, 2019, projects that the United States will become a net energy exporter in 2020 and is projected to remain so through 2050 as a result of large production increases in crude oil, natural gas, and natural gas plant liquids (NGPL) coupled with slower growth in U.S. energy consumption.

The United States produced 10.9 million barrels per day (b/d) of crude oil in 2018, passing the 10 million b/d mark for the first time and surpassing the previous record of 9.6 million b/d set in 1970, according to Short-Term Energy Outlook January 2019. The growth in liquid fuels production is projected to continue through 2050. In the short term, EIA also forecasts the United States to be a net exporter of petroleum in the fourth quarter of 2020, with liquid fuel net exports exceeding crude oil net exports by nearly 0.9 million b/d.

Similarly, natural gas production reached an all-time high in 2018. Production of natural gas and NGPL is expected to have the highest growth of all fossil fuels and account for nearly one-third of U.S. liquids production through 2050. Natural gas prices are projected to remain comparatively low through 2050, leading to increased use of natural gas across end-use sectors as well as increasing LNG exports.

The electric power sector is projected to see a notable shift in fuel mix. Growth in solar, wind, and natural gas-fired electricity generation is projected to be accompanied by additional retirements of coal and nuclear power plants. As a result of this changing fuel mix, the electric power sector is projected to see a steady decrease in carbon dioxide (CO_2) intensity after 2030. Carbon dioxide intensity refers to CO_2 emissions per unit energy output in British thermal units.

Total energy

The United States becomes a net energy exporter in 2020

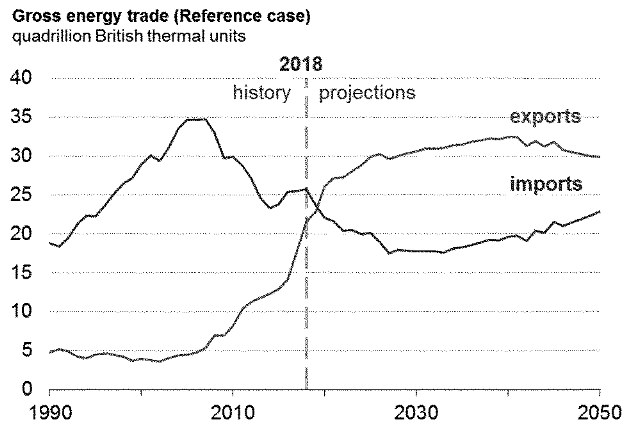
The United States is projected to become a net energy exporter in 2020 in the AEO2019 Reference case for the first time since the 1950s. The projected changes in net energy trade are driven mostly by evolving trade flows of liquid fuels and natural gas, and the United States will remain a net energy exporter through 2050, as increases in crude oil, natural gas, and natural gas plant liquids production continue to outpace growth in domestic consumption of petroleum products.

EIA projects that the gap between energy imports and exports widens until the 2040s when falling domestic crude oil production leads to a decrease in exports, and a growing U.S. economy and higher domestic gasoline consumption leads to increase imports. (Figure 4).

Although the United States is expected to become a net energy exporter, heavy and medium crude oil will continue to be imported through the projection period to meet the needs of many U.S. refiners. An increasing share of United States crude oil production is expected to be light and sweet oil, but much of the Gulf Coast refining capacity is optimized to process heavy, sour crude grades.

In addition to configurational mismatches between production and refining, transportation constraints also will continue to lead refiners to rely on crude oil imports to meet refining capacity. For example, insufficient infrastructure exists to move the necessary crude oil production supply from the Gulf region to meet domestic refinery demand on the East and West Coasts.

Figure 4. United States energy imports and exports, 1990-2050



The United States will continue to be a net exporter of coal and coke, but exports are not expected to increase because of competition from other global suppliers closer to major consuming markets.

Petroleum liquids production

U.S. crude oil and natural gas plant liquids production exceeds its peak 1970 level; consumption of petroleum liquids remains lower than its 2004 peak level

The United States is now the largest producer of crude oil in the world. According to AEO2019 projections, U.S. crude oil production will continue to grow as upstream producers increase output because of rising prices and cost reductions.

U.S. crude oil production continues to set annual records exceeding 14.0 million b/d in the mid-2020s and remaining above that level through 2040. The continued development of tight oil and shale gas resources, particularly those in the East and Southwest regions, supports growth in NGPL production. NGPL production, already at a record high, is projected to grow in the long term, exceeding 6 million b/d before 2030.

Petroleum product consumption is projected to remain mostly steady through the projection period, although projected consumption is sensitive to changes in assumptions regarding oil prices and economic growth.

As a result of increasing crude oil and other petroleum liquids production and relatively unchanged petroleum product consumption, the United States is projected to be a net exporter of petroleum on a volume basis from 2020 to 2049.

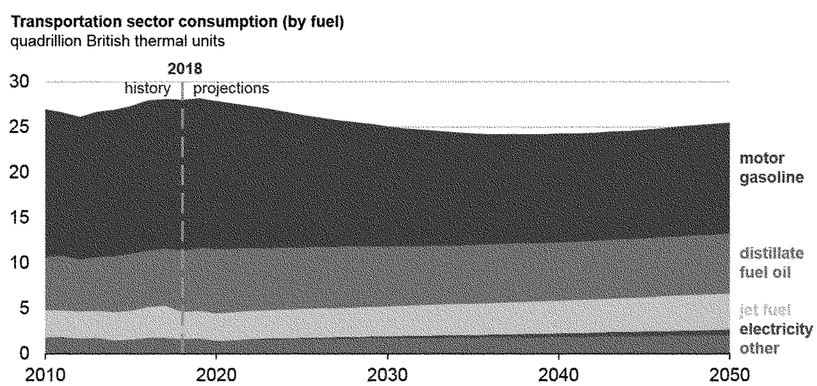
Petroleum liquids consumption

Transportation energy consumption generally declines between 2019 and 2037 as fuel economy increases offset growth in vehicle miles traveled

Figure 5 shows jet fuel energy consumption will grow more than any other transportation fuel during the projection period as increases in GDP lead to growth in air transportation that outpaces increases in aircraft fuel efficiency. Electricity use in the transportation sector starts from a relatively low base and continues to grow through 2050.

Motor gasoline and distillate fuel oil's combined share of total transportation energy consumption decreases through 2050 as a result of gains in energy efficiency supported by current laws and regulation. However, assuming no further policy actions, while increases in fuel economy standards reduce the total consumption of motor gasoline through the mid-2020s, the plateauing of mandated energy efficiency gains after 2027 is projected to result in increasing consumption of motor gasoline in the second part of the projection period (Figure 5).

Figure 5. Transportation sector consumption declines through 2037



Natural gas

Natural gas production growth outpaces natural gas consumption growth

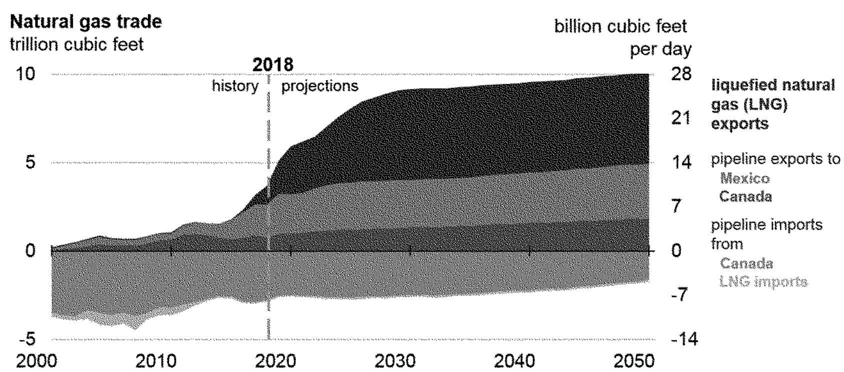
Domestic natural gas production increases through the projection period, driven by tight and shale natural gas production. The size of the associated resources and the improvements in technology allow for the development of tight and shale resources at lower costs. In particular, the eastern United States is projected to drive the growth in natural gas output, followed by production growth along the Gulf Coast. Dry natural gas production reaches 43.4 Tcf by 2050.

Growth in drilling in the Southwest region drives increases in natural gas production from tight oil formations. Because drilling activity in oil formations primarily depends on crude oil prices rather than on natural gas prices, the increase in natural gas production from oil-directed drilling puts downward pressure on natural gas prices.

Offshore natural gas production in the United States remains mostly unchanged during the projection period as production from new discoveries generally offset declines in legacy fields.

The projected growth in U.S. natural gas consumption, although significant, is not expected to keep pace with production growth, allowing net natural gas exports to continue to grow through 2050 (Figure 6). As additional LNG export terminals are constructed, growth in exports is projected to be led by waterborne trade, but LNG exports will remain highly sensitive to crude oil and natural gas prices.

Figure 6. Net exports of natural gas will continue to grow through 2050



Electric power

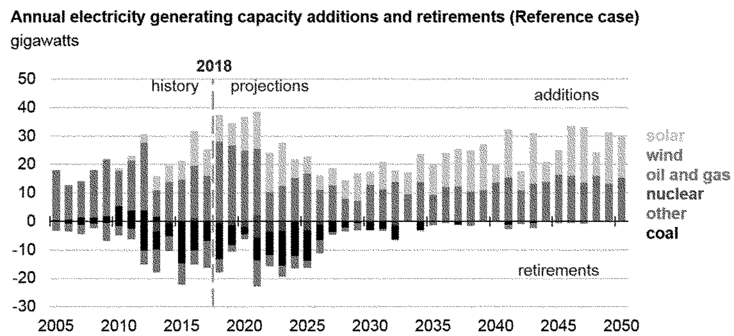
Electric power and industrial demand drive natural gas consumption

Continued, relatively low natural gas prices will lead to increasing use of natural gas across most end-use sectors. The industrial sector is projected to be the largest consumer of natural gas, as the chemical industry and industrial heat and power grow through the projection period.

Relatively low natural gas prices also lead to higher use of natural gas for electric power generation. Natural gas-powered generation is projected to grow through the projection period and remain the largest fuel by share in this sector through 2050 in the Reference case, under current laws and regulations.

Additions to electric power generation will be met by natural gas and renewables
Generation from renewable electricity sources, including hydroelectricity, grows the most during the projection period. This growth is initially supported by various tax incentives that are expected to phase out through the 2020s. Without the tax incentives, renewable generation continues to grow, but at a slower rate, as capital costs to construct new generating capacity continue to decline.

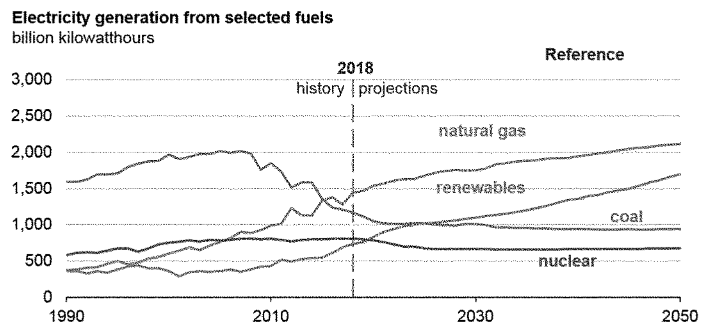
Figure 7. Natural gas and renewables additions dominate



Although coal and nuclear continue to decrease in nearly all cases, these fuels will continue to play a role in the U.S. electricity generation mix through the projection period. Renewable electricity generation surpasses nuclear generation about 2020 and surpasses coal about 2025 (Figure 8).

Long-term trends in capacity additions for electricity generation are dominated by the addition of solar and natural gas capacity. Wind capacity additions are more modest, and less economically competitive coal, nuclear, and natural gas plants are expected to see capacity retirements. About 42% of coal-fired capacity and about 22% of current nuclear capacity is projected to retire by 2050.

Figure 8. Electric power generation mix sees a transformation in the medium term



Natural gas prices and policy incentives drive the growth in electricity generation fuel mix. In the AEO2019 Reference case, relatively low natural gas prices lead to natural gas-powered generation growing steadily and remaining the dominant fuel through 2050. However, these results are highly sensitive to natural gas prices. AEO2019 side cases show that low natural gas prices favor the growth of natural gas-power generation, while high natural gas prices favor renewable generation. In the high natural gas price case, renewables are projected to become the leading source of electricity generation by 2030. (Figure 7).

Carbon dioxide

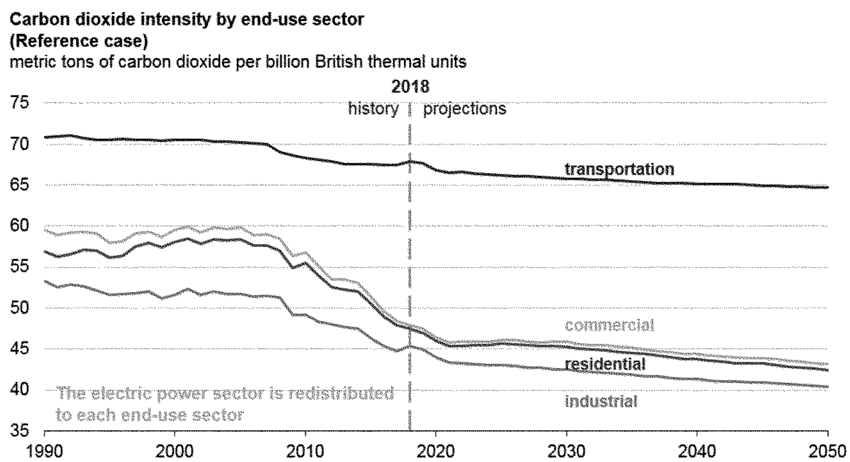
Despite overall increases in energy consumption, carbon dioxide intensity declines across end-use sectors

Changes in the fuel mix primarily drive the lower carbon dioxide (CO2) intensity, which can vary greatly depending on the mix of fuels consumed in each sector. For example, the generation fuel mix in the electric power sector now relies on less carbon-intensive sources, such as natural gas and renewables. This fuel mix is in contrast to the fuel mix a decade ago when the electric power sector relied on coal as a feedstock. Given the projected trends in the electric power sector fuel mix, CO2 will continue to decrease through 2050.

In 2018, CO2 emissions increased by 3% as a result of increased energy consumption. Consumption rose due to robust economic growth and unfavorable weather conditions. EIA projects that emissions will remain at least 2% lower than the 2020 level across the projection period. However, EIA projects that energy-related CO2 emissions will initially decline through 2040 and then increase in the last decade of the projection period. This pattern primarily follows petroleum emissions. Petroleum emissions are projected to decline until 2040, but they will then rise as vehicle-miles traveled increase and motor gasoline consumption begins to increase again toward the end of the projection period. The increase in gasoline consumption is a result of current regulations not requiring additional fuel efficiency increases after 2027. This projection is highly uncertain because many fuel efficiency standards are currently under discussion.

Natural gas CO2 emissions are projected to increase through 2050, and coal-related CO2 emissions are projected to decline as coal-fired electric power plants retire. The generation fuel mix in the electric power sector has changed significantly since the mid-2000s, with lower generation from high-carbon intensive coal and higher generation from natural gas and carbon-free renewables, such as wind and solar. This change resulted in the overall CO2 intensity of the electric power sector declining by 25% from the mid-2000s to 2018 and continuing to decline through 2050. Electric power, however, can be considered in the context of each end-use sector, and Figure 9 shows CO2 intensities with the electric power sector redistributed to each end-use sector. Carbon intensities are calculated as carbon dioxide emissions per unit energy output in British thermal units.

Figure 9. Carbon dioxide intensity by end-use sector



Note: Carbon dioxide intensities are calculated as carbon dioxide emissions per unit energy output (in British thermal units).

About EIA

The U.S. Energy Information Administration (EIA) was established by the Department of Energy Organization Act of 1977 as the primary federal government authority on energy statistics and analysis. It is one of the 13 principal federal statistical agencies and is responsible for collecting, analyzing, and disseminating relevant, accurate, and timely energy information to inform public and private decision-making.

EIA neither formulates nor advocates policy conclusions; and, by law, its data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. Therefore, EIA reports should not be construed as products of the U.S. Department of Energy or other federal agencies.

EIA Annual Energy Outlook (AEO) and Short-Term Energy Outlook (STEO)
EIA prepares short- and long-term outlooks. The *Short-Term Energy Outlook* (STEO) examines trends over the next one to two years. The *Annual Energy Outlook* (AEO) models projections over the next 20 to 25 years.

EIA's AEO2019 was released on January 24, 2019. It is the annual report on the long-term outlook for the energy system of the United States and provides data projections through 2050. Like all modeled projections and forecasts, the AEO2019 projections depend on input assumptions that are highly uncertain. However, the Reference case assumes current laws and regulations remain unchanged during the projection period, which makes it a useful as a baseline that can inform potential future policy discussions.

EIA's STEO is a monthly forecast covering the current and upcoming calendar year, and it provides monthly forecast data for supply, consumption, and prices across energy commodities. The STEO published January 15, 2019, is the first to include forecasts for 2020.

Conclusion
This is an exciting and transformational time for the United States energy industry as world energy markets adjust to the United States becoming a major global supplier and exporter for years to come.

Madam Chairman and Members of the Committee, thank you for the opportunity to present this information. This concludes my testimony.

The CHAIRMAN. Thank you, Dr. Capuano.
Mr. Book, welcome.

STATEMENT OF KEVIN BOOK, MANAGING DIRECTOR, CLEARVIEW ENERGY PARTNERS, LLC

Mr. BOOK. Good morning, Chairman Murkowski, good morning and congratulations, Ranking Member Manchin and distinguished members of the Committee.

My name is Kevin Book and I head the research team at ClearView Energy Partners, an independent firm that serves institutional investors and corporate strategists. Thank you for inviting me to contribute to your outlook for energy and minerals markets. I'm grateful for the work you do to maximize economic and environmental security. The rapid pace of change in energy markets can make this task as difficult as it is important.

Let me briefly summarize several takeaways from my written testimony.

First, over the decade from 2008 to 2018, U.S. liquids supply vastly outgrew U.S. liquids demand. Supply rose by 9.3 million barrels per day, a compound growth rate of 7.6 percent. And as EIA has noted, roughly 68 percent of global supply growth came from the U.S. Demand grew a little less than one million barrels per day, a compound growth rate of 0.5 percent, whereas global demand grew at nearly three times that rate.

That is one case for exports and here is another. The oil we add to global supply benefits U.S. producers and overseas buyers but also U.S. drivers because U.S. pump prices tend to reflect global oil balances.

Second, thanks to diversification and efficiency, generating $1.00 of U.S. GDP today requires about four-fifths as much oil as it did a decade ago. From a personal consumption standpoint, the average American now puts 17 percent less of his or her wallet into the gas tank and compared to other major consumer nations. U.S. demand looks more price responsive and less GDP bound. Put another way, overseas demand looks robust and pretty stable. "Peak demand" zeitgeist today may be as premature as peak supply seemed a decade ago.

Third, for all that, demand risks do loom. Instead of gasoline leading global demand growth as it did from 2013 to 2017, jet fuel and liquid petroleum gases drove demand growth last year. This may reflect efficiency gains and demand responses to higher prices, especially in countries with weaker currencies.

Weaker global growth prospects could bring demand headwinds this year. So, too, could trade war. Import adjustments like steel tariffs can impair producer economics. It could be hard to see in a favorable price environment, but when price is weakened tariffs can deter or delay investment in production and infrastructure. Trade war can diminish market access.

Oil tends to be highly fungible but not perfectly interchangeable. Mismatches between crude quality and refinery configuration can force producers to sell at discounts. And because LNG requires specialized regasification infrastructure, it can be particularly trade vulnerable.

Trade war can also chill global activity economically by introducing frictional costs and stalling investment. This too is hard to measure, but deals that don't happen today may explain future export opportunities that fail to materialize.

Fourth, OPEC continues to play a major role. Last year Saudi monthly output ranged from 9.9 million barrels per day at the low end to 11.1 million barrels per day at the high end. Full compliance with the targets OPEC and cooperating parties set last December imply output cuts totalling 1.3 million barrels per day.

Meanwhile, unplanned outages are rising, Venezuela's output was collapsing before the latest U.S. sanctions, and new sanctions seem likely to accelerate production declines. Even so, new projects in Angola and Nigeria could help to offset Venezuelan losses, as could a continued output surge in Iraq.

Thus, our firm currently anticipates a slightly oversupplied crude market for the year as a whole with key uncertainties remaining, Iran and Saudi Arabia.

To close with three observations.

For one, we are seeing a newfound energy security giving American diplomats greater flexibility to address geostrategic rivals by an economic statecraft. This is a big difference.

Second, thanks to the demand changes I mentioned, high oil prices don't hurt our economy as much as they used to, but thanks to the supply changes I mentioned, low oil prices may start to hurt it more. Let me be very clear, few people want higher gasoline prices, but we may not want rock bottom crude prices either.

Last, in 10 years the U.S. went from trying to survive scarcity to adapting to adequacy. Thanks to your strong leadership, Madam Chairman, and your colleagues, the Congress reconfigured America's energy security policy. The coming era of net exports that the Administrator mentioned promises even more opportunity, but realizing it could require even bigger policy changes.

For example, as regulators reinterpret old laws for new realities, legal challenges create investment delays and uncertainty, especially for energy transportation infrastructure. Maximizing the benefits of exports may require greater regulatory clarity concerning the pipelines that move liquids and natural gas resources to export facilities, and to the extent that energy transportation has become a proxy climate battleground, such pipeline challenges may prove both less economically efficient and less politically durable than market-based price signals.

Madam Chairman, this concludes my prepared testimony. I look forward to answering any questions you or your colleagues may have at the appropriate time.

[The prepared statement of Mr. Book follows:]

TESTIMONY OF KEVIN BOOK
MANAGING DIRECTOR,
CLEARVIEW ENERGY PARTNERS, LLC

BEFORE THE
U.S. SENATE COMMITTEE
ON ENERGY AND NATURAL RESOURCES

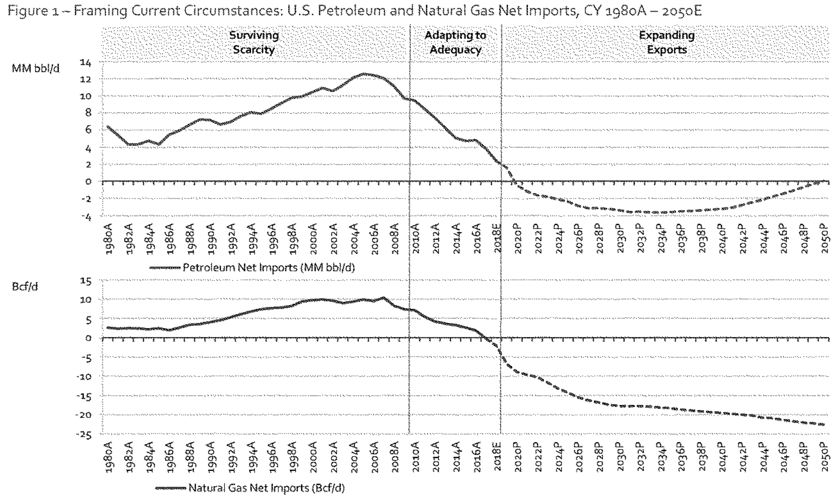
FEBRUARY 5, 2019

Good morning, Chairman Murkowski, Ranking Member Manchin and distinguished Members of this Committee. My name is Kevin Book, and I head the research team at ClearView Energy Partners, LLC, an independent firm that serves institutional investors and corporate strategists.

Thank you for inviting me to contribute to your outlook for energy and minerals markets for the 116th Congress. I am grateful for the work this Committee does to maximize economic and environmental security. The rapid pace of change and the complexity of energy markets can make the task as difficult as it is important.

Sometimes, however, even amid such complexity, a single picture can tell a very clear story. For example, Figure 1, presented below, may offer a useful summary of the fundamental circumstances that underpin today's oil and gas policy opportunities and challenges.

Figure 1 – Framing Current Circumstances: U.S. Petroleum and Natural Gas Net Imports, CY 1980A – 2050E



Notes:
- Data from 1980 to 2017 reflect historical, actual (A) volumes.
- CY 2018 and beyond reflect estimates (E) and projections (P) from EIA's *2019 Annual Energy Outlook* reference case, Tables 11 and 13.

Source: ClearView Energy Partners, LLC, using EIA data

Using data from the Energy Information Administration (EIA), Figure 1 traces more than three decades of our nation's long history as a net importer of both petroleum and natural gas and conjoins those historical trends with EIA's latest reference case projections from the *2019 Annual Energy Outlook* (AEO). The blue line represents historical net petroleum imports, the green line represents historical net natural gas imports and, in both cases, the dashed lines correspond to calendar year (CY) 2018 estimates and forward projections for CY 2019 through CY 2050.

As you and your colleagues know well, sound energy policy comprises more than an assessment of net imports. Even so, at the risk of oversimplification, I have divided the past and future of net imports into three distinct oil and gas policy eras:

- **Surviving scarcity,** a multi-decadal interval of fast-growing net import reliance;
- **Adapting to adequacy,** a directional shift over the course of roughly a decade during which both net import trends inverted and then accelerated to the downside; and
- **Expanding exports,** the present and near future. The U.S. became a net natural gas exporter during CY 2017. By the EIA's assessment, our country could become a net petroleum exporter by the end of CY 2020.

As is often the case in energy markets, the shift from scarcity to adequacy came on subtly at first, then suddenly. Thanks in large part to strong leadership from you, Madam Chairman, and your colleagues on this Committee, the Congress worked to reconfigure America's expansive, legacy energy security apparatus as our nation regained a measure of economic freedom.

The era of adequacy now appears to be giving way to a new era of net exports that could bring even greater economic and security benefits. But realizing those opportunities could also present this Committee and other centers of U.S. energy policy leadership with even vaster challenges than retooling scarcity-based policy for an era of adequacy.

Much of that recent adaptation required regulators to reinterpret old laws for new circumstances. The resulting rulemakings and decisions have faced legal challenges that created investment delays and project uncertainties, especially for energy transportation infrastructure. Securing the economic and security benefits of expanded exports may require further substantive policy renovations that, among other things, alleviate these delays and uncertainties.

The balance of my testimony offers a market overview with an eye towards the next phase of America's oil and gas history.

Market Conditions: U.S. Production Supplying Global Demand

Figure 2 summarizes U.S. and global supply and demand figures from EIA's most recent *Short Term Energy Outlook* (STEO).

Figure 2 – U.S. Production Accounted for ~68% of Global Liquids Supply Growth between CY 2008 and CY 2018

Year	U.S. Liquids Supply (MM bbl/d)	Global Liquids Supply (MM bbl/d)	U.S. Share of Change (%)	U.S. Demand (MM bbl/d)	Global Demand (MM bbl/d)	U.S. Share of Change (%)
2008	8.56	86.66		19.50	86.83	
2013	12.36	91.63		18.97	92.26	
2018	17.87	100.40		20.46	100.00	
Change, 2013 vs. 2008	+ 3.80	+ 4.96	77%	− 0.53	+ 5.43	-10%
Change, 2018 vs. 2013	+ 5.50	+ 8.77	63%	+ 1.49	+ 7.74	19%
Change, 2018 vs. 2008	+ 9.30	+ 13.74	68%	+ 0.96	+ 13.17	7%
5Y CAGR, 2018	7.6%	1.8%		1.5%	1.6%	
10Y CAGR, 2018	7.6%	1.5%		0.5%	1.4%	

Source: ClearView Energy Partners, LLC, using EIA data

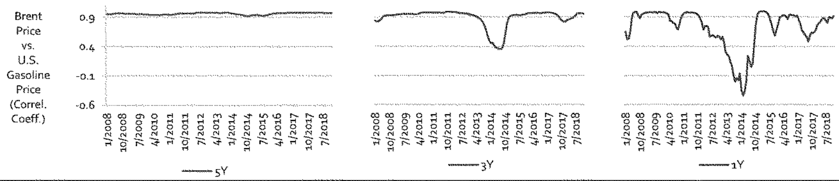
According to EIA data, U.S. liquids supply – that is, inclusive of crude oil, refined products, natural gas liquids (NGLs) and biofuels – grew by 9.3 MM bbl/d between CY 2008 and CY 2018, a compound annual growth rate (CAGR) of ~7.6%. That pace far outstripped global liquids supply, which grew by 13.74 MM bbl/d, a ~1.5% CAGR. Taken together, the two figures imply that the U.S. accounted for ~68% of global supply growth over the ten-year interval, a statistic that would have defied imagination a decade ago.

U.S. liquids demand grew much more slowly than U.S. liquids supply, rising only ~0.96 MM bbl/d, a ~0.5% CAGR, over the course of the decade. Global demand, by contrast, grew at a faster pace over the interval, climbing by 13.17 MM bbl/d, a ~1.4% CAGR (~1.6% during the latter five years of the decade).

Supply growth in excess of domestic demand may form the fundamental underpinnings for exports, but I would suggest that there may be more to the story. Not only can U.S. additions to global supply economically benefit U.S. producers and overseas importers, but also U.S. drivers, because U.S. gasoline prices tend to reflect global oil market supply balances and, concomitantly, prices.

Over the decade from CY 2008 to CY 2018, average U.S. pump prices correlated closely with the Brent crude prices (the principal international benchmark for light, sweet oil), as presented in Figure 3.[1]

Figure 3 – Domestic Implications of Global Balances: U.S. Gasoline Prices Correlates Closely with Brent Crude, 1/2008 – 12/2018

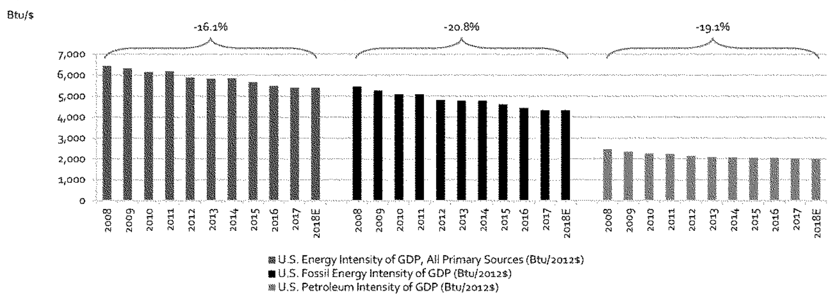


Source: ClearView Energy Partners, LLC, using EIA data

As it turns out, economic circumstances for many U.S. drivers may be changing in other ways, too. Much of the flattening of domestic consumption appears to reflect both diversification and structural efficiency gains across the U.S. economy, including the transportation sector. Such changes tend to reduce the economic vulnerability of energy end-use sectors to petroleum price shocks.

Figure 4, below, shows that real U.S. energy intensity of GDP - in this case, the amount of primary energy required to generate a dollar of economic output in chained 2012 dollars - declined by ~16% between CY 2008 and CY 2018.

Figure 4 – A More Intensely Resilient Economy: Energy Intensity of U.S. Real GDP, CY 2008 – CY2018E



Note: CY 2018 estimates reflect year-to-date averages through September.

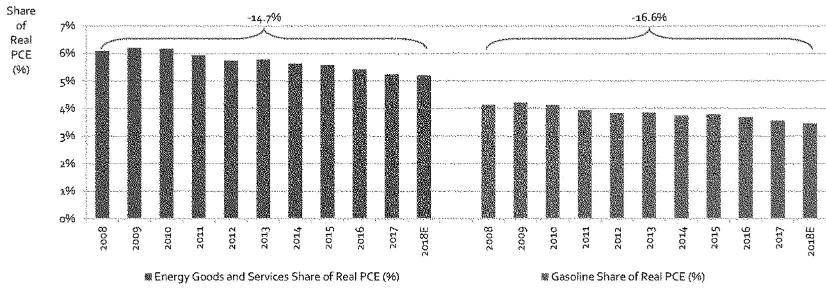
Source: ClearView Energy Partners, LLC, using BEA and EIA data

Fossil energy intensity of GDP declined by ~21%, which can be explained in part by the rapid growth of non-hydro renewable generation, but also by thermal efficiency gains as generators shifted from steam-cycle coal plants to combined cycle gas turbines. Similarly, the ~19% decline in petroleum intensity of GDP can be explained in part by the brisk introduction of ethanol and biodiesel in the fuel mix, but also by efficiency gains in cars, trucks and airplanes.

[1] The correlation breakdowns in the one- and three-year series reflect deep discounts for U.S. crude, as measured by the differential between Brent and the West Texas Intermediate (WTI) benchmark, due to oil gluts in the Midwest and Gulf Coast prior to the 2015 lifting of the crude oil export ban.

Lower prices and greater energy efficiency, in tandem with rising incomes, reduced U.S. energy outlays as a share of real personal consumption expenditures (PCE, Figure 5, below). Over the ten-year interval between CY 2008 and CY 2018, energy PCE as a whole fell by ~15%, according to data from the Bureau of Economic Analysis (BEA), and gasoline PCE fell by ~17%. Simply put, the average U.S. driver now appears to be better insulated against pump price volatility.

Figure 5 – A More Resilient End-User: Energy Share of Personal Consumption Expenditures, CY 2008 – CY 2018E



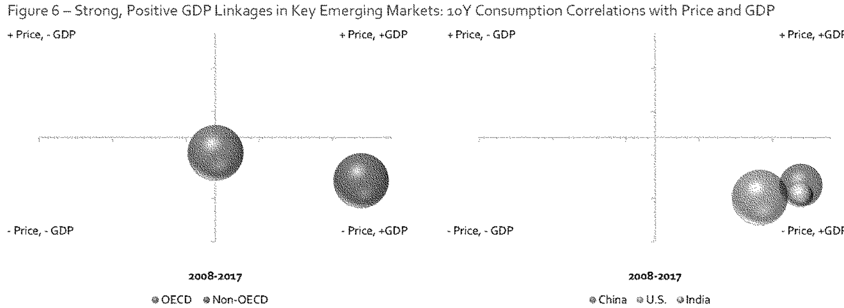
Note: CY 2018 data reflect averages through November (all energy) and September (gasoline).

Source: ClearView Energy Partners, LLC, using BEA data

U.S. consumption also appears more price-responsive and less-GDP bound that other major consumer nations. As presented in Figure 6, below, overall OECD petroleum consumption (represented by the dark blue bubble in the chart on the left side) did not correlate significantly with real Brent crude prices or with real GDP over the ten years from CY 2008 to CY 2017. Non-OECD consumption (dark green bubble), by contrast, exhibited a strong inverse correlation with price (i.e., consumption trended up when prices fell and *vice-versa*) and a strong positive correlation with GDP.

Compared to China (the world's #2 petroleum consumer and #1 importer, represented by the red bubble in the chart on the right side of Figure 6), and India (the #4 global consumer, but growing fast, yellow bubble), U.S. consumption inversely correlated more strongly with real Brent crude prices and less strongly with real GDP. One interpretation may be that the U.S. was a more flexible, less-captive petroleum consumer than China, India or the OECD as a whole.

Figure 6 – Strong, Positive GDP Linkages in Key Emerging Markets: 10Y Consumption Correlations with Price and GDP



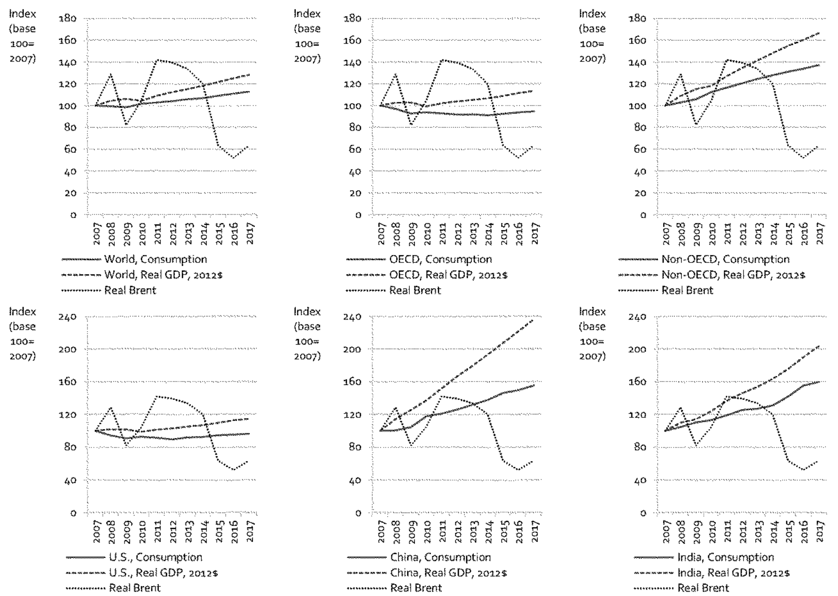
Note: Bubble size corresponds to average share of global consumption over the 10Y correlation interval (i.e., from CY 2008 to CY 2017).

Source: ClearView Energy Partners, LLC, using BEA, BP, EIA and World Bank data

Figure 7, below, offers a different view of the same data set. Each chart shows consumption (blue lines), real GDP (red dashed lines) and real Brent prices (black dotted lines). All three data series are presented as 2012-based indices (i.e., where 100 corresponds to CY 2012 average levels), and the Brent index is the same in each of the six charts.

The top row of charts illustrates the degree to which, in the aggregate, fast-growing, emerging economies also happen to be fast-growing petroleum consumers, compared to advanced economies and to the world as a whole. In the bottom row of charts, which revisits the comparison between the U.S., China and India, the latter two nations' historical correlations between GDP growth and petroleum consumption growth seem even more pronounced.

Figure 7 – Fast-Growing Non-OECD Consumption vs. Flat-to-Down OECD Consumption



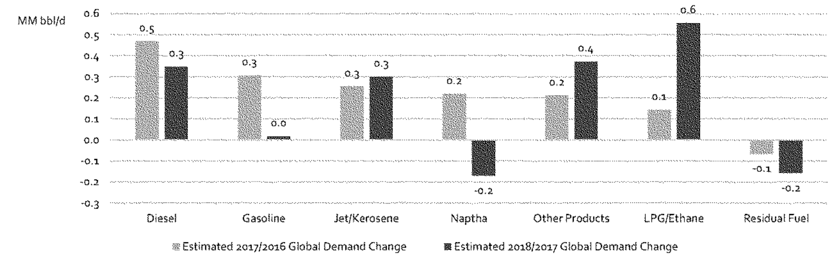
Source: ClearView Energy Partners, LLC, using BEA, BP, EIA and World Bank data

One might interpret Figures 6 and 7 as proxies for U.S. producers' export opportunity set: overseas demand appears robust and relatively inflexible, particularly in the near term. The International Energy Agency's (IEA) January 2019 *Oil Market Report* projects 1.4 MM bbl/d of CY 2019 liquids growth, and the EIA's January 2019 STEO projects 1.5 MM bbl/d.

In this context, I would suggest that "peak demand" *zeitgeist* may be as premature today as "peak supply" prognostications were more than a decade ago when I had the honor of appearing before this Committee during a period of high prices.[2] That said, our Firm sees several potential downside risks to IEA and EIA CY 2019 demand forecasts. For one, the composition of global demand growth appears to have changed recently. Using IEA data, our Firm estimates that gasoline demand increased only 0.1% relative to year-ago levels during CY 2018, well below its 2.4%/Y annual average growth rate over the CY 2013-2017 interval. Volumetrically speaking, the largest year-on-year (Y/Y) demand increases during CY 2018 came from liquefied petroleum gas (LPG)/ethane, other refined products and jet fuel, as presented in Figure 8 (next page).

[2] For details, please refer to testimony I delivered at an April 3, 2008 Full Committee Hearing *To examine the influence of non-commercial, institutional investors on the price of oil.*

Figure 8 – Gasoline Stopped Driving Global Oil Demand Growth in CY 2018

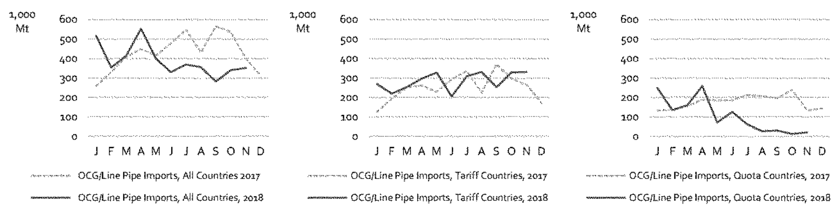


Source: ClearView Energy Partners, LLC, using IEA data

This flattening of gasoline demand seems likely to reflect a combination of light-duty vehicle efficiency gains and a demand retracement in response to CY 2018 petroleum price increases. Drivers purchasing refined products in countries with weak currencies may have been particularly affected by last year's combination of dollar strength and crude price appreciation.

Weaker global growth could be another source of demand downside. The International Monetary Fund (IMF) has twice downgraded its CY 2019 economic forecast due, in part, to the implications of U.S.-China trade war. We see three principal trade-related risks for oil and gas producers. First, U.S. import adjustments can impair producer economics. Tariffs increase producers' cost of line pipe and oil country goods (OCG, tubular steel used in wells), and quotas can create temporary supply-chain dislocations that limit well or pipeline construction. Figure 9 presents our analysis of data from the U.S. Commerce Department's International Trade Administration (ITA).

Figure 9 – As of November, CY 2018 Oil Country Goods and Line Pipe Imports Had Declined ~12% vs. CY 2017



Country, Region or Grouping (1,000 MT)	2015	2016	2017	TTM 11/2018	YTD 11/2017A	YTD 11/2018E	TTM 11/2018E vs. CY 2017 (%)	YTD 11/2018E vs. YTD 11/2017A (%)
Oil Country Goods and Line Pipe								
World	4,336.7	2,289.9	5,126.6	4,570.3	4,813.6	4,257.3	-10.9%	-11.6%
-- Imports from Quota Countries								
Argentina	90.7	50.3	199.1	158.6	181.0	140.5	-20.4%	-22.4%
Brazil	104.9	30.2	200.8	147.9	172.1	119.2	-26.4%	-30.8%
Korea	1,341.5	757.2	1,711.8	978.4	1,616.0	882.7	-42.8%	-45.4%
All Quota Countries	1,537.1	837.7	2,111.7	1,284.9	1,969.2	1,142.4	-39.2%	-42.0%
-- Imports from Excluded Countries								
Australia	0.010	0.008	0.045	0.000	0.045	0.000	-99.7%	-99.7%
-- Imports from Tariff Countries								
Total E.U.	868.0	402.8	683.8	877.1	646.6	839.9	28.3%	29.9%
Canada	434.8	94.6	338.8	418.9	311.4	391.5	23.6%	25.7%
Mexico	328.7	327.8	581.1	593.9	533.1	545.8	2.2%	2.4%
All Tariff Countries	2,799.6	1,452.2	3,014.8	3,285.4	2,844.4	3,114.9	9.0%	9.5%

Source: ClearView Energy Partners, LLC, using ITA data

Overall line pipe and OCG steel imports year-to-date (YTD) through November 2018 were down about ~12%, slightly more than steel imports of all kinds over the same interval (~10%, but not included in Figure 9). Imports from the three countries subject to quantitative restrictions - Argentina, Brazil and South Korea - were down ~42% vs. year-ago levels, and volumes from countries subject to tariffs were up ~10%. This suggests a growing producer reliance on tariff-adjusted imports.

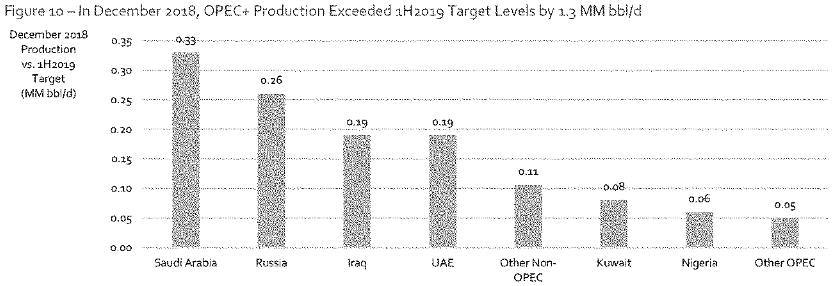
In a favorable oil and gas price environment, it may be difficult to assess the first-order impacts of such policies. Sponsors of marginal projects may not wish to communicate the fragility of their economics to competitors (or shippers, in the case of infrastructure projects). A less-favorable oil and gas price environment can make more projects marginal, however, meaning that steel tariffs that inflate 10% to 15% of overall project costs by 25% (i.e., 2.5% - 3.75% of the whole) could potentially deter or delay investment in production and transportation capacity.

Second, trade war can result in lost market access. Crude oil and petroleum products tend to be highly fungible if not perfectly interchangeable. Mismatches between crude quality and refinery complexity (i.e., facilities' capabilities to economically process heavy, sour crude) can force producers to sell at discounts relative to prevailing prices in optimal markets, particularly during times of seasonal or cyclical demand weakness. LNG, in particular, requires specialized regasification infrastructure that can render U.S. exporters more vulnerable to trade strictures.

Finally, trade war has potential to chill global economic activity, both explicitly (i.e., from the frictional costs associated with redirecting trade flows and reallocating global value chains) and implicitly (i.e., from forgone investment due to uncertainty). As with factor cost inflation, it can be difficult to directly gauge the scale and duration of foregone investment, but the deals that don't happen today may show up as export opportunities that fail to materialize in the future. In addition, the current composition of demand growth may be particularly exposed to trade risk: weakening logistics and travel demand could weigh on jet fuel consumption, and retaliatory tariffs could put U.S. exports of petrochemical feedstocks at relative disadvantage to competing sources.

Notwithstanding the recent centrality of U.S. production to global supply growth, output decisions by the Organization of the Petroleum Exporting Countries (OPEC) and cooperating producers (collectively, "OPEC+") continue to play a major role in global balances. Last year, Saudi Arabia's average monthly production ranged from 9.9 MM bbl/d at the low end to 11.1 MM bbl/d at the high end, reinforcing its role as a swing producer. As such, the Kingdom continues to lead OPEC+ market balancing efforts. By our analysis, the 1H2019 production targets that OPEC+ established last month imply that production levels must decrease 1.3 MM bbl/d from December 2018 levels to achieve 100% compliance, as presented in Figure 10.

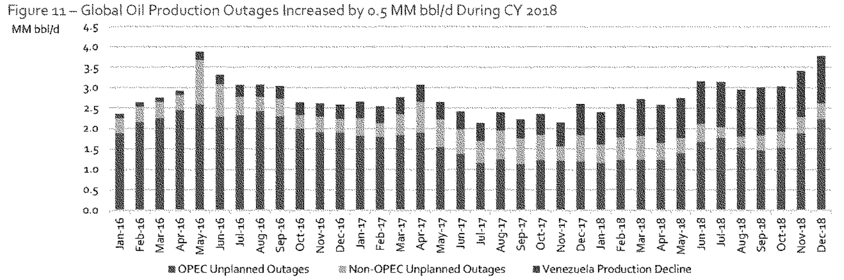
Figure 10 – In December 2018, OPEC+ Production Exceeded 1H2019 Target Levels by 1.3 MM bbl/d



Source: ClearView Energy Partners, LLC, using IEA data

Unplanned outages and production impairments often impact global balances, as well. EIA data indicate that unplanned outages increased by ~0.5 MM bbl/d last year, and Venezuela's output collapse further tightened global supply. Figure 11 (next page) presents both impacts.

Figure 11 – Global Oil Production Outages Increased by 0.5 MM bbl/d During CY 2018



Note: Venezuela's production decline is measured against its average production level of 2.4 MM bbl/d over the CY 2006-2015 interval.

Source: ClearView Energy Partners, LLC, using EIA data

After significant declines during CY 2017 and 1H2018, Venezuelan oil production stabilized during 2H2018 at monthly averages in a tight range between 1.25 MM bbl/d and 1.27 MM bbl/d, according to IEA data. The January 28 U.S. petroleum-sector sanctions on Venezuela could accelerate production declines as CY 2019 wears on. Prohibitions barring U.S. diluent exports to Venezuela could reduce the country's heavy oil production capabilities. In addition, the discontinuation of heavy oil exports to the U.S could force Venezuela to discount formerly U.S.-bound barrels in order to draw new buyers and/or accommodate greater shipping costs, consuming cash that could fund upstream operations.

Even so, our Firm currently anticipates a slightly oversupplied crude market in CY 2019, with Iran and Saudi Arabia producing a combined ~13 MM bbl/d. Major project start-ups in Angola and Nigeria could help to offset potential production declines in Venezuela. In addition, Iraqi production reached a record high of 4.7 MM bbl/d in December 2018 due, in part, to exports from Northern Iraq rising to 0.5 MM bbl/d, the highest level in more than a year. Iraq has exceeded its OPEC production target since August 2018, and we expect this trend to continue in CY 2019. Figure 12, below, summarizes our projections.

Figure 12 – We Expect Iranian Plus Saudi Arabian Oil Production to Total ~ 13.0 MM bbl/d in CY 2019

(MM BBL/D)	1Q2018	2Q2018	3Q2018	4Q2018	1Q2019P	2Q2019P	3Q2019P	4Q2019P
Global Oil Demand	98.3	98.7	99.8	100.1	99.5	100.4	101.3	101.4
Non OPEC Oil Supply	60.9	61.9	63.2	63.4	63.0	63.7	64.6	64.7
OPEC NGLs	5.6	5.6	5.6	5.7	5.7	5.7	5.7	5.7
Call on OPEC Oil Supply	31.8	31.2	31.0	31.0	30.8	31.0	31.0	31.0
Actual OPEC Oil Supply	31.7	31.5	32.0	32.2	31.1	31.1	31.1	31.1
Oil Supply - Oil Demand	-0.1	0.3	1.0	1.2	0.3	0.1	0.1	0.1
Iran Production	3.8	3.8	3.6	3.0	2.8	2.6	2.6	2.8
Saudi Arabia Production	10.0	10.1	10.4	10.8	10.2	10.4	10.4	10.2
Other OPEC Countries Production	18.5	18.2	18.6	18.4	18.1	18.1	18.1	18.1

Note: OPEC totals exclude Qatari production of 0.6 MM bbl/d of oil and 1.3 MM bbl/d of NGLs because Qatar exited OPEC as of January 2019.

Source: ClearView Energy Partners, LLC, using IEA data

Implications of an Era of Expanding Exports

Scholars and academics have noted that newfound energy security provides American diplomats with greater flexibility to address geostrategic rivals via economic statecraft. The surge of U.S. oil production at the start of the decade helped to keep a lid on prices during the Iran oil sanctions that preceded the *Joint Comprehensive Plan of Action* (JCPOA, the 2015 Iran nuclear deal), and a similar dynamic seems likely to govern the sanctions' November 2018 reinstatement. In a similar fashion, even though the chemical composition of U.S. light, tight oil differs substantially from that of Venezuelan heavy, sour oil, America's continued production growth could provide some degree of cushion against volumetric losses resulting from the aforementioned sanctions targeting the regime of titular Venezuelan President Nicolás Maduro.

In light of those dynamics, I would suggest that – in some ways – oil and gas production growth may have facilitated the updating of U.S. foreign policy faster than the updating of U.S. domestic energy policy. Although this sequencing appears to reflect the urgency that often accompanies security issues rather than a deliberate choice by U.S. policymakers, it does not seem optimal. Indeed, a policy orientation towards the expansion of oil and gas exports could potentially enhance the foreign policy toolkit that supply security has provided to date. To the extent that the movement of additional American molecules to international markets can buffer global balances against supply shortfalls, U.S. energy could create further economic space for new diplomatic and military options.

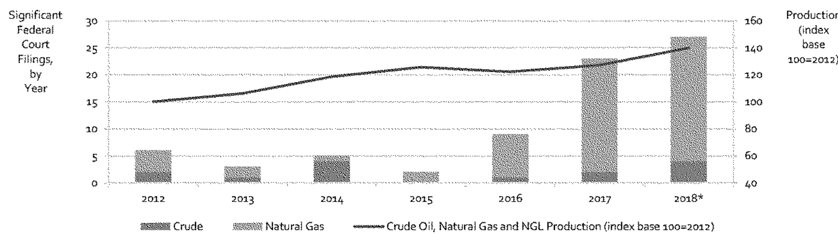
Domestically, the ramifications of low oil prices for our economy could change as U.S. consumption, production and net import dynamics evolve. Let me clearly preface my next point: I do not prefer higher gasoline prices. It does not seem a stretch to suggest that most of the world, with the exception of a small number of undiversified, major, producer-exporter nations, does not favor higher fuel costs, either. Even in some of those producer nations (and the more prolific oil-producing U.S. states), the number of licensed drivers vastly outstrips the number of oil industry and oilfield services employees.

At the same time, if falling oil prices do not yet hurt the overall U.S. economy more than they help it, they soon might. In theory, an investment multiplier could imbue oil and gas capital spending with the power to deliver greater economic upside than the consumer surplus resulting from gasoline price declines. Indeed, given that investment multipliers tend to be higher in economies with low marginal propensities to save, a dollar spent at the wellhead in the U.S. may have potential to drive considerably more economic activity than a dollar saved at the service island. As an added macroeconomic irony, falling pump prices may prove increasingly underwhelming as an economic stimulus for end-users that have become more efficient.

On a net basis, then, as U.S. liquids production approaches parity with U.S. liquids consumption, falling prices could slow economic growth. This tipping point could arrive even though combined U.S. liquids generally sell at a discount to benchmark crudes such as West Texas Intermediate, or WTI (reflecting a rich cut of lower-value NGLs) and gasoline usually sells at a premium to WTI (as a consequence of refining margins).

On a final note, time series data from our Firm's internal database of significant federal court filings (which largely excludes eminent domain proceedings) indicates that domestic production growth has corresponded to a rising number of filings by pipeline opponents, as presented in Figure 13.

Figure 13 – As Domestic Production Grows, Federal Court Challenges Mount against Infrastructure



*Preliminary; CY 2018 court filing data as of early December 2018. CY 2018 production data reflect trailing, twelve-month total crude oil, natural gas and NGL production (in quadrillions of Btu) as of September 2018.

Source: ClearView Energy Partners, LLC, using EIA and PACER and federal courts data

Recognizing that a fulsome discussion of this topic is likely to fall outside the market focus of this hearing, I would cursorily suggest that maximizing the benefits of export expansion may depend on greater regulatory clarity concerning the pipelines that transport liquids and natural gas resources to export facilities. Moreover, to the extent that energy transportation has become a proxy climate battleground, such pipeline challenges may prove to be both less economically efficient and less politically durable than market-based price signals.

Madam Chairman, this concludes my prepared testimony. I will look forward to answering any questions you or your colleagues may have at the appropriate time.

The CHAIRMAN. Thank you, Mr. Book. We always appreciate your input.

Mr. Kavulla.

STATEMENT OF TRAVIS KAVULLA, DIRECTOR, ENERGY & ENVIRONMENTAL POLICY, R STREET INSTITUTE

Mr. KAVULLA. Thank you, Madam Chairman and Ranking Member Manchin, for the opportunity today.

As Dr. Capuano noted, the electricity market is wrapping up a decade that has seen tremendous change that few analysts would have projected at the beginning of the decade. That fact, the unpredictability of the energy economy, suggests that it is important to have an electric market that does not pre-ordain outcomes through mandates or subsidies. Yet in some parts of the country, such as the western United States, many power plants still obtain contracts not through market-based pricing or competitive solicitations but instead based on regulators' guesses about what energy will cost over the next 20 years. Nearly all of these guesses have turned out to be wrong and consumers have suffered because of it.

The Public Utility Regulatory Policies Act, or PURPA, was modified 15 years ago by Congress to allow FERC to update its implementation for changing market conditions. It is now time for FERC to do so by allowing states to use a robust system of competitive solicitations to meet their PURPA obligations.

Elsewhere, states rely on regional transmission organizations, or RTOs, to deliver price signals to indicate whether a power plant should be built or an existing one should be retired. Because of this, Ohio and Pennsylvania have seen huge investments in shale gas and the Great Plains have seen a surge of wind.

Unfortunately, not everyone is satisfied with competition. The sector is seeing a growing number of state legislatures intervene to stack the deck in favor of a particular outcome. We now have a sorry situation where many states are either mandating that certain resources enter the market or subsidizing other resources to prevent them from leaving the market. Some states are doing both at the same time.

The unfortunate result of this trend is that nearly everywhere consumers are paying more than they need to for power plants that are not necessary to deliver them energy. In fact, NERC reports that all but a single region of the country, Texas, has generating capacity well in excess of customer needs. Wholesale prices reflect this glut of power capacity. In PJM, the RTO that spans from Virginia to Illinois, wholesale prices declined 40 percent over a decade. But even so, regulated retail rates, the dumping ground for the costs of these subsidies which consumers pay, have risen in the same area.

Subsidizing uneconomic power plants leaves the remaining unsubsidized plants at a competitive disadvantage. FERC has attempted to deal fairness in the situation, but the proposals that it is now contemplating are sadly a road to nowhere. For example, FERC is now entertaining a proposal by PJM called, "carve out and repricing." Under this market design PJM would "carve out" subsidized resources from participating in the capacity auction and "reprice" the auction's outcome as if those power plants simply did not exist. The PJM proposal thus invents a kind of parallel universe in order to get the right, which is to say higher, price.

In the meantime, FERC has a lot of other work it could and should be doing. It has no more important job than to ensure the prices on wholesale electric markets actually reflect the system conditions underlying them, especially in times when the grid is stressed and resources are scarce. To give an example, last week parts of the United States saw the coldest temperatures in decades. Energy emergencies, as Senator Manchin pointed out, were declared by governors and the mid-continent independent system operators scrapped business as usual practices to ensure power plants were available.

And yet, prices did not appear to reflect these stressed conditions. Market data from MISO and PJM show that at the Minnesota and Chicago pricing hubs, where temperatures were very cold, prices on January 31st peaked at $167 and $126 per megawatt-hour, respectively. These are four to six times higher than the average annual prices but they hardly reflect an emergency or anything close to stressed system conditions. In a grid that will eventually be more volatile because of a significant number of weather-dependent renewables, it is important that the prices actually reflect real-time system operating conditions and reward generators that are online during these times.

Finally, as Mr. Book pointed out, the electricity markets operate across a physical network that needs to be robust in order to ensure the grid is reliable. There are too many examples where one state's siting and permitting decisions effectively act to obstruct one or more states' energy policies.

Here it is worth contemplating the role of the Federal Government. There is a strong economic and reliability case that certain areas, such as New England, need more natural gas capacity while other areas, such as the West, could use more electric transmission. If efficient siting of this infrastructure cannot occur, then the robustness and reliability of the electricity market will always be in question.

Madam Chairman, Ranking Member Manchin, I appreciate the opportunity and I've filed a full set of written testimony.

[The prepared statement of Mr. Kavulla follows:]

Testimony on behalf of the

R Street Institute

by

Travis Kavulla

Director, Energy & Environmental Policy

before the

United States Senate

Committee on Energy & Natural Resources

hearing entitled

"Outlook for Energy and Minerals Markets in the 116th Congress"

Feb. 5, 2019

Thank you, Chairman Murkowski and Ranking Member Manchin, for the opportunity to testify today. In this 116th Session of the United States Congress, the electricity market will be wrapping up a decade that has seen tremendous change. Natural gas has boomed as a source of energy, coal has declined, and both because of policy interventions and their falling costs, over the next two decades, renewable sources of energy are poised to make up a significant, and perhaps even a majority, share of energy.

Few of these outcomes were predicted at the outset of this century or even at the beginning of the last decade. That fact—the unpredictability of the energy economy—suggests that it is important to have an electricity market that does not pre-ordain outcomes through mandates and subsidies. Instead, it is important to consumers that the market prices electricity at its value, in real time and on that basis, sends meaningful price signals to those who would develop, invest in or contract for new and existing technologies.

There are many opportunities for important reforms in the electricity markets. Most of these fall squarely in the lap of the wholesale electricity markets' federal regulator, the Federal Energy Regulatory Commission (FERC). Still, others are the business of state legislatures and public utility commissions. However, there are places where congressional intervention, whether through legislation or oversight, would be useful.

Accordingly, my testimony highlights a few of the issues associated with the evolving market for electricity and begins with a law that has not aged especially well in light of all the changes we have seen in the electricity market, the Public Utility Regulatory Policies Act of 1978, or PURPA.

PURPA Reform

The most important section of PURPA requires utilities to buy the energy and capacity of certain Qualifying Facilities (QFs) at a non-discriminatory rate.[1] FERC interpreted this to mean that the price paid to QFs should equal the avoided cost or the price that a utility would otherwise pay to acquire the same quantity of energy and capacity.[2] However, this fair-sounding principle fails to work in practice.

For nearly a decade, I served as a utility regulator at the Montana Public Service Commission. In determining PURPA rates, I took estimates and projections of nearly a dozen different variables—for example, the price of natural gas, the capital cost of new power plants or the future tax that might be associated with a ton of carbon dioxide emissions—and ran those estimates through a formula, which in turn spit out a number. My colleagues and I then issued a regulatory order, which, with little confidence, was our best estimate of the cost of energy over the next two decades. It is almost needless to say that my projections were almost-always wrong. Sometimes they were too low, in which case few, if any, QFs would contract with the utility. And sometimes the prices I ordained were too high, in which case a bonanza of QFs flooded the utility's doors to take advantage of this generous rate. This is where PURPA's internal logic crumbles. PURPA developers typically sign contracts when the avoided cost is too high, not when it is too low. Now that FERC and the states collectively have four decades of experience under PURPA, it is clear why PURPA projects tend to be some of the highest-cost projects in any given jurisdiction.

The fundamental problem of PURPA is *not* the requirement that utilities purchase energy from independent developers, provided it is as or more affordable than if the utility built a project itself. Instead, the problem is the fact that the administrative price forecasting on which PURPA's implementation relies is a suboptimal way to engage in what economists call "price discovery." A competitive solicitation allows rival parties to bid against one another in the hope of obtaining the business of consumers. PURPA, meanwhile, turns "price discovery" into an act of litigation, with a QF and a utility each trying to convince a government regulator what the right "price" is.

Ironically, PURPA today may actually be a barrier to state attempts to contract with lower-cost renewables. In August 2017, Public Service Co. of Colorado, an Xcel operating company, issued

[1] Public Utility Regulatory Policies Act of 1978, 92 Stat. 3157, (codified at 16 USC § 824a-3).
[2] 18 CFR § 292.304.

a competitive solicitation. It received a large number of extraordinarily low-cost bids for renewable energy. The Colorado Public Utilities Commission reviewed the bids and approved the utility's proposal to select a number of independent projects that had submitted low bids. However, relying on PURPA, a bidder who was not awarded a contract asserted a right to sell the output of 17 projects totaling about 1,400 megawatts of generation to the utility, and claimed that it should be awarded an "avoided-cost" rate based on an administrative calculation using 2016 data. That rate would be significantly higher than prices that emerged from the solicitation. And because the utility does not actually require that amount of energy to serve its customers, accepting the jilted bidder's PURPA claims would mean either canceling projects that *were* low-cost bidders or buying more energy than customers actually need.

Citing this example and others, the National Association of Regulatory Utility Commissioners (NARUC) has issued a proposal, which calls upon FERC to waive PURPA's mandatory purchase obligations for those states that have competitive frameworks for the procurement of energy and capacity.[3] This would allow FERC to establish regulations that ensure that the state frameworks are genuinely competitive and open to QF technologies. And it would allow states to avoid the sure-to-be-wrong rigmarole of decreeing prices through regulatory forecasts. FERC already has granted a limited exemption to utilities in the footprints of Regional Transmission Organizations (RTOs). Yet, even in those states outside of RTOs, such as in the Western United States, the use of competitive solicitations is widespread. In the Energy Policy Act of 2005, Congress has also clearly signaled to FERC that the agency should be flexible as market models for electricity develop. In NARUC's proposal, FERC has an opportunity to reform PURPA in a way that is even-handed to all. The agency should take that opportunity.

State Subsidies and Competitive Markets for Electricity

As the market for electricity has changed, it has created winners—and losers. In many parts of the country, the cost of new entry for certain power plants is less than the going-forward cost of operating certain existing generators. In such conditions, an efficient market will cause existing resources to retire in the face of lower-cost new entrants. This trend is natural and economically rational—indeed, it is a sign of innovation within an industry.

This trend is not solely due to economics, however. It has been accelerated by state and federal policies. State mandates and federal tax subsidies allow resources that would not otherwise be economical to enter the market.[4] At the same time, several states have recently adopted

[3] Travis Kavulla and Jennifer Murphy, "Aligning PURPA with the Modern Energy Landscape: A Proposal to FERC," National Association of Regulatory Utility Commissioners, October 2018. https://pubs.naruc.org/pub.cfm?id=E265148B-C5CF-206F-514B-1575A998A847.
[4] However, for the first time this year, Lazard projects that the average *unsubsidized* levelized cost of energy produced by new wind is less than the average LCOE of existing coal. "Levelized Cost of Energy Analysis," Version 12.0, Lazard, 2019. https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-

policies to subsidize the continued operation of certain existing resources, which otherwise would have retired in the face of competition by both subsidized and unsubsidized new entrants.[5] Still other jurisdictions, where power generation is owned by regulated utilities, effectively have shielded power plants from the economic pressures of competition, more subtly directing subsidies to out-of-market resources in the form of ratepayer guarantees.[6]

In short, policymakers are subsidizing certain resources to enter the market and policymakers are also subsidizing other resources to prevent them from leaving. Moreover, while these policy interventions were at one point relatively limited in nature, they have grown in number and in scale over the last few years. These developments have borne out a prediction made by the independent market monitor of one of the nation's largest electricity markets, PJM, when he observed that: "Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies."[7] According to a 2018 report by the market monitor, in the PJM market alone, these subsidies were estimated to total $3.8 billion, although the number would certainly be higher today.[8] This is a significant number when compared to the total revenue resulting from the PJM capacity auction—$10.3 billion for 2018.

The inevitable result of these subsidy policies is that consumers, in one form or another, are paying for power plants that they do not need. For this 2018/19 winter season, NERC projects that each region of the country had significantly more resources available than were needed when compared to total consumer demand and while including a margin for reserves.[9] When one turns to the summer analysis that NERC conducts, the story is much the same, although the

2018. It should be noted that the LCOE analysis employed by Lazard has its critics and other authors suggest that the LCOE of new renewables remains higher than the marginal cost of existing plants. See, for example, Gurcan Gulen, "Electricity Markets, the Grid, and the Net Social Cost of Energy," *forthcoming*.

[5] New York, Illinois, New Jersey and Connecticut.

[6] About one-third of the United States population is served by vertically integrated utilities, the power-generation-related revenue of which is a function of the generation's cost to operate, rather than its value in the wider wholesale market.

[7] "Statement of Joe Bowring, Independent Market Monitor for PJM," FERC Technical Conference on State Policies and Wholesale Markets, May 1-2, 2017, p. 3. https://www.ferc.gov/CalendarFiles/20170426150935-Bowring,%20Monitoring%20Analytics.pdf.

[8] "The Value of Markets," PJM, June 2018, p. 5. https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/the-value-of-pjm-markets.ashx.

[9] "2018/2019 Winter Reliability Assessment," North American Electric Reliability Corporation, p. 7. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2018_2019_Draft.pdf.

Texas electric market, which has a market design that aggressively promotes economic efficiency, naturally has a much tighter operating margin.[10]

FERC's Regulation of Capacity Markets

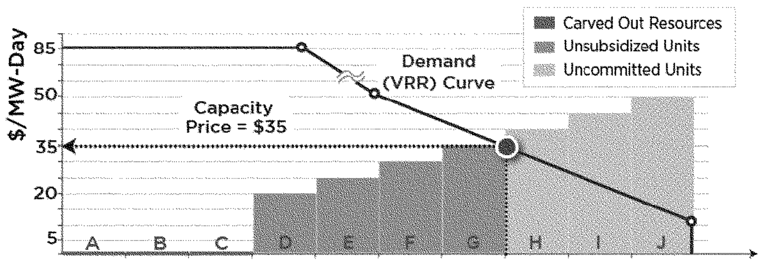
If it were not for subsidies favoring certain power plants, other unsubsidized resources would be economical. In an effort to deal fairness to those unsubsidized market participants, the Regional Transmission Organizations (RTOs) and the Federal Energy Regulatory Commission (FERC) have frequently re-designed parts of the electric wholesale markets to deliver them additional revenue. A special focus of these initiatives has been the centralized capacity markets the eastern RTOs[11] administer, where reforms have sought to mitigate the effect of subsidies and preserve a "competitive" price signal to generators who do not benefit from subsidies.

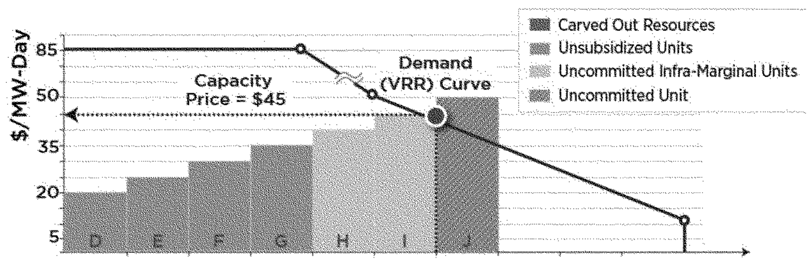
Though well intentioned, these efforts are a road to nowhere. An instructive example in this regard is PJM's proposal for "carve out and repricing." Under this market design, PJM would "carve out" subsidized resources from participation in its capacity auction and "reprice" the auction's outcome as if those power plants did not exist. However, when actual supply is artificially removed but demand is held steady, prices of course rise. Illustratively, PJM's proposal to carve out subsidized resources is shown below:[12]

[10] "2018 Summer Reliability Assessment," North American Electric Reliability Corporation, 2018. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf. The Public Utility Commission of Texas recently modified the method by which operating reserves are procured by the market, making the procurement more robust in times when customer demand and weather-dependent intermittent resources are volatile

[11] By "eastern RTOs," I include PJM, ISO-New England and the New York ISO. Each of these operate markets where incumbent utilities do not own the bulk of power generation on a traditional "cost-of-service" basis, and where power generators instead expect those revenues derived from RTOs' energy and capacity auctions either to make up the bulk of their revenues, or to form the basis on which forward contracts and hedges are priced. Other RTOs, including the Midcontinent ISO, the Southwest Power Pool and the California ISO largely exist to optimize the dispatch of resource entry and exit decisions that occur at a more granular state- or utility-level.

[12] Images taken from "Initial Submission of PJM Interconnection," FERC Dkt EL18-178-000, Oct. 2,2018, pp. 66-67.





For whatever virtue there may be in attempting to preserve a so-called "competitive" price signal, the PJM proposal invents a kind of parallel universe in order to get the "right" (i.e., higher) prices. PJM had asked FERC to rule on this proposal last month but the matter remains pending as of the submission of this testimony. I am sympathetic to those enterprises that have not received subsidies but face competition by subsidized resources. However, I am concerned that the remedy PJM has proposed is a reform that makes its market more and more an arbitrary, administrative construct and less and less a market whose prices are the function of the real balance of supply against demand.

The simple reality is that the only way to eliminate subsidies is to eliminate the subsidies. Yet this kind of preemption of state policies is not something that FERC has suggested. Indeed, it has argued against it—making the regulator one of the few federal agencies to adopt a self-denying, modest view of its powers.[13]

[13] *Brief of the United States and the Federal Energy Regulatory Commission as Amici Curiae in Support of Defendants-Respondents and Affirmance*, Case No. 17-2433 (7th Circuit, 2018). Available at: https://www.ferc.gov/legal/court-cases/briefs/2018/7th17-2433etalVillageofOldMillCreekAmicusBrief.pdf.

Congress's Role relative to State Subsidies

So what is to be done? In recent years, the most dynamic movers of subsidies and out-of-market payments are state legislatures and public utility commissions. Congress could pass a law expressly countermanding state policies. However, this would represent a marked shift in the division of federal and state jurisdiction over electricity generation. Although the effects of power generation in large regional grids are interstate in nature, the Federal Power Act and subsequent energy laws largely reserve the authority over electricity generation to the province of state policymaking. Congress's decision to leave this networked industry in the hands of local regulators causes this networked industry not to resemble others, like telecommunications or railroads, which were, at first, gradually and then in the 1980s and 1990s, quite rapidly federalized in order to promote consistent standards and economic efficiency.

If Congress does not act, then a two-staged future could occur. In the short term, I would expect more state legislatures to adopt policies that subsidize politically favored sources of electricity. However, in the medium-to-longer term, subsidies for electricity will cause regulated rates in those subsidy-prone states to rise, even while the overall effect of the subsidies—keeping more supply than is necessary to meet regional consumer demand—will suppress prices available on the wholesale market. PJM's wholesale prices have declined 40 percent in the past decade, even while regulated retail prices have *increased*.[14]

The consumers of subsidy-prone states will thus pay higher rates and the ultimate winners—the beneficiaries of a surplus that other states' consumers have paid for—will be the consumers of states that have been less profligate. In this way, the electricity markets have a similar dynamic to dumping in the context of foreign trade: Dumping has negative effects on local manufacturers but is fundamentally a wealth transfer from the producing nation to the consumers of the nation who buy the product. In the same way, a state that has not (yet) doled out subsidies to power generation, like Ohio, may be crowded out of opportunities to develop power plants that would be economical in a marketplace free of subsidies. Yet, Ohio's electricity consumers, large and small, ultimately would benefit from others states' decisions to subsidize their production.

Should they grow too ostentatious, subsidy policies may generate a political feedback loop in the subsidizing states, where politics can be expected to tolerate such a giveaway for only so long. In places with rising regulated rates and falling wholesale costs, one can already see the dissatisfaction on the part of consumers who would rather pay the latter. This is what has given rise to Community Choice Aggregators in California, to the movement by casinos and data centers in Nevada to directly access the wholesale market and to demands by industrial customers in Michigan to cap "direct access," which limits participation. Ultimately, it will be the dissatisfaction of the most essential component of the energy system—the consumer—that

[14] "The Value of Markets," p. 2. https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/the-value-of-pjm-markets.ashx.

will impose discipline on policymakers whose decisions raise costs too radically. Empowering those consumers will help accelerate that discipline.

Congress has previously invited states to consider energy policies—instead of mandating them—on a host of topics, from PURPA's direction to consider time-of-use rates[15] to the Energy Policy Act of 1992's definition and direction to consider integrated resource planning[16] to the Energy Policy Act of 2005's direction on net-metering.[17] Rather than intervene with a heavy hand, what Congress can and should do, in any general energy legislation, is to encourage states to consider increasing customer choice. Additionally, through the Department of Energy, it should consider making funds available to states who elect this policy in order to set up an online marketplace for customers to shop for an energy provider of their choice.[18] Finally, Congress should consider requiring states to disclose the cost of carbon reductions associated with particular subsidies and to consider providing for a disclosure on consumers' bills.[19] This would help promote customer and policymaker consideration about potentially cheaper ways to obtain the same reductions.

Electricity policy remains entirely too paternalistic and there is today no sound policy reason why sophisticated consumers of electricity should have to buy a product ordained for them by a regulator. If more states allowed direct access to the wholesale market by even their largest consumers of energy, policymakers would also be able to put to the test the proposition underlying many subsidy policies: that consumers are demanding clean energy. In my view, they are—and they will be willing to contract for it separately, in quantities that they choose and at competitive prices.

[15] Public Utility Regulatory Policies Act of 1978, 92 Stat. 3117 (codified at 16 USC § 2621)
[16] Energy Policy Act of 1992, 106 Stat. 2776 (codified at 16 USC §§ 2602, 2621).
[17] Energy Policy Act of 2005, 119 Stat. 594, 962 (codified at 16 USC § 2621).
[18] While large customers are sophisticated enough to shop for electricity providers on their own, websites established in certain states with customer-choice policies that allow residential customers to shop around are transparent, easy-to-use tools that allow customers to choose between different rate plans, contract lengths and products (e.g., all-renewable) See, for example, http://www.powertochoose.org.
[19] The PJM market monitor independently calculated that the implied cost of carbon reductions associated with the solar renewable energy credit obligation of the District of Columbia is $861.52 per tonne—a cost which is orders of magnitude above the cost of carbon reductions obtained by more efficient policies in the region. This fee is charged to district residents through a non-bypassable fee on the distribution side of the customer bill, which means that even the District's policy of customer choice does not allow customers to avoid it. However, if more transparently priced on the customer bill, it might create momentum to seek alternative, more cost-effective policies. See: "Quarterly State of the Market Report for PJM: January through June," Monitoring Analytics, LLC, August 2018, p. 329.

Pricing Electricity at its True Value in Wholesale Markets

The RTOs and FERC have consumed a significant amount of time and resources attempting to fix the eastern RTOs' capacity markets. At the same time, other problems of market design deserve their urgent attention.

Many states have passed or will pass mandates that require their utilities to procure a certain percentage of clean energy resources by a certain year. The most ambitious states have pushed 100 percent clean energy targets in just two or three decades. Much of this clean energy will be weather-dependent renewable resources, especially wind and solar power. Since the fuel for these resources is free, they are sometimes referred to as "zero-marginal-cost" resources. While they have substantial capital costs in the first place, once built and if properly maintained, they produce energy essentially without cost in any given hour when their fuel (the sun or the wind) is available. (In fact, because of federal production tax credits, which yield a tax benefit equivalent of $24 per megawatt-hour but *only* when the wind produces, this form of subsidy actually causes certain wind generators to be willing to *pay* customers to take their energy output.[20]) Axiomatically, in the auctions of RTOs, the wholesale price of energy is a function of the most expensive unit of supply necessary to meet consumer demand. However, when a system is so dominated by renewables that its output is sufficient to meet customers' needs, the wholesale price of energy may be zero or even become negative.

Yet, there will also be periods when the sun is not shining and the wind is not blowing. Some of these periods are highly predictable—the evening for solar. Some are somewhat predictable—for example, the relative intensity of the wind by season, e.g., in a place where Santa Ana winds tend to blow. And some of these periods are hardly predictable at all—as in the case of a passing cloud or the vacillations in wind speed on a gusty day.

The longer periods of intermittency introduced by renewables, as well as the more unpredictable episodes of volatility, have profound implications for the grid. The energy markets' prices should appropriately reflect these more volatile system conditions and periods of scarcity. Such prices provide an economic signal for the construction and operation of the most cost-effective and reliable set of resources that can make up the gap when other resources are temporarily , or for hours, or for days, unavailable. In the future, what we had come to think of as "capacity" resources will instead need to fill this breach flexibly but durably and be compensated by or on the basis of the energy-market prices during times of system

[20] The production tax credit (PTC) is being phased out but many wind projects have been safe-harbored by IRS guidance associated with the beginning of these construction projects. For projects that began construction during or before 2016, the full value of the PTC for ten years is given. The PTC steps down by 20 percent each year thereafter and, unless Congress renews the program, is unavailable for projects that commence in 2020 or after. See: "Renewable Energy Tax Credit," U.S. Dept. of Energy, accessed Jan. 31, 2019. https://www.energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

scarcity or stress.[21] At the moment and for a variety of technical reasons, the prices in RTOs during times of system stress or scarcity do not reflect these tight system conditions. Instead, during these periods, market operators all too often take administrative actions that have the effect of suppressing the market price, while socializing the cost of system scarcity or stress.

FERC should begin to address these more essential questions of electricity market regulation in the 21st century. A good starting point is for FERC to give priority consideration to the proposals that will emerge from PJM's work on energy price formation and reserve products.[22] As a second-order issue and after it concludes its work on energy pricing reforms, FERC should then consider whether additional safeguards associated with add-on reliability products or standards are needed. Politics has forced this issue into a defining role of electricity-market discussions but it is, in fact, a sideshow to the basics of electricity market reform, which should convey appropriate economic incentives to generators to assure reliability. An appropriate end result to such work would be an electricity market that fully supplants today's mandatory capacity markets.

Ensuring Energy Transport Networks are Robust

Finally, it is necessary to ensure that the underlying networks on which the market in electricity relies—the electric and natural gas transmission systems—remain robust and reliable.

Siting both natural gas pipelines and electric transmission lines has become more challenging over the past ten years. Environmentalists have routinely objected to natural gas pipelines, although it is natural gas more than any other source of electric power that has achieved the greatest carbon-emissions reductions in the electricity sector.[23] Electric transmission, meanwhile, is cost-effective only when sited above ground, except in very limited circumstances; landowners and neighbors object to it on aesthetic and land-use grounds. For different reasons, probably more of each of this infrastructure is necessary, at least in certain places. More electric transmission will be necessary in order to ensure renewable energy resources can reach population centers, and in doing so a grid should be knit together that has more diversity of resources—and thus less of the volatility described above. Natural gas transmission, meanwhile, is a cornerstone of reliable grid operations. Although some have suggested that such assets will not be needed in a system largely dominated by renewables, this is inapposite: Gas transmission provides a form of energy storage that can be called upon

[21] A short explanation of the principles behind this are laid out in William Hogan, "In My View: Best Electricity Market Design Practices," 2018. https://sites.hks.harvard.edu/fs/whogan/7_Best_Practices%20(Hogan)_RCH_03_10_18MIH_rev_final_072518.pdf.
[22] "Board Directs PJM, Stakeholders on Reserve Pricing," PJM, Dec. 6, 2018. http://insidelines.pjm.com/board-directs-pjm-stakeholders-on-reserve-pricing.
[23] "Global Energy & CO2 Status Report," International Energy Agency, accessed Jan. 31, 2019. https://www.iea.org/geco/emissions.

during periods of renewable intermittency and volatility. Even if less natural gas is ultimately used in power plants to generate electricity, having more gas transmission capacity—as well as back-up fuel sources for those power plants—is a reliable feature that becomes more important in a system with, for example, less coal and more renewables.

These issues of infrastructure siting have taken on a dimension wherein certain states obstruct the energy policies of other states that are geographically unlucky. New England's RTO, the ISO-New England, has repeatedly warned that without additional natural gas capacity, its system faces reliability risks.[24] In 2015, New England's governors unanimously adopted a policy statement calling for additional gas infrastructure.[25] Meanwhile, New York has imposed a *de facto* moratorium on natural gas pipelines—using state authority over water permits to frustrate a largely FERC-jurisdictional process under the Natural Gas Act. This means that New England states cannot access one of the most productive gas fields in North America, located across New York in Pennsylvania and Ohio.

Similar issues arise in electricity transmission. Several interstate transmission lines have been proposed to facilitate the development of renewable energy, and approvals have been obtained in one state, only to be blocked in others.[26] This has prevented interior states with rich renewable resources from developing their energy economy and it has also prevented states interested in purchasing renewables from accessing their intended supply.

Although not related to domestic electricity production, a similar story has unfolded with the State of Washington and Cowlitz County's environmental review of the Millennium Bulk Terminals' proposal for a coal export facility at Longview, Washington. Wyoming and Montana have both extensively promoted the coal mined in the Powder River Basin for Asian export but those development prospects have effectively been blocked by a single state.[27]

Congress should therefore consider whether individual states should be permitted to frustrate the energy policies of other states so wantonly. Some scholars have suggested empowering the

[24] "Natural Gas Infrastructure Constraints," ISO-New England, accessed Jan. 31, 2019. https://www.iso-ne.com/about/regional-electricity-outlook/grid-in-transition-opportunities-and-challenges/natural-gas-infrastructure-constraints.
[25] "Governors' Statement on Regional Cooperation on Energy Infrastructure," New England States Committee on Electricity, April 23, 2015. http://nescoe.com/resource-center/govs-stmt-apr2015.
[26] Examples include Northern Pass to bring Quebec hydropower to Massachusetts and the Grain Belt Express to bring wind from Kansas to the MISO market.
[27] Tom Lutey, "Montana, Wyoming join battle over Washington coal port," *Billings Gazette* May 11, 2018. https://billingsgazette.com/news/state-and-regional/montana/montana-wyoming-join-battle-over-washington-coal-port/article_a09eaa35-4538-5b1c-8174-510e70de95e0.html.

FERC "to approve all modes of interstate energy transport."[28] I would not go that far. However, it is necessary to have a backstop federal permitting regime, which could act as a "tie breaker" when one state has sited or declared through policy the need for energy infrastructure and another has declined to permit or rejected a permit for the same. Additional protections could be written into such a statute, including a requirement that linear infrastructure have a certain amount of its mileage signed up through voluntary landowner agreements before it may resort to eminent domain. Or, for those projects where the off-taker entity is an affiliate of the developer of the transmission line or pipeline, a stricter standard for project necessity might apply. But, for projects that have an arm's-length and voluntary relationship between the infrastructure owner and the entity or entities paying for it, the federal statute could allow permitting to be accomplished more easily, on the basis that stronger evidence exists as to need.

Once again, it has been my pleasure to testify before you today. I appreciate the Committee's consideration of my views, and I wish you luck and wisdom as you approach your work in this session of Congress.

[28] James W. Coleman, "Pipelines and Power-lines: Building the Energy Transport Future," *Ohio State Law Journal* 79 (*forthcoming 2019*), p. 43.
https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3172652

The CHAIRMAN. That will be included as part of the record.

Thank you for joining us.

Mr. Moores, welcome to the Committee.

STATEMENT OF SIMON MOORES, MANAGING DIRECTOR, BENCHMARK MINERAL INTELLIGENCE

Mr. MOORES. Great, thank you very much, Chairman Murkowski, Ranking Member Manchin, fellow Committee members. It's a pleasure to be back and for you to welcome Benchmark Mineral Intelligence.

We are in the midst of a global battery arms race in which so far the U.S. is a bystander. The advent of electric vehicles (EVs) and energy storage has sparked a wave of battery megafactories that are being built around the world.

Since my last testimony only 14 months ago, we have gone from 17 lithium-ion battery megafactories to 70. So, 17 to 70. In gigawatt-hour terms we have gone from 289 gigawatt-hours to 1,549 gigawatt-hours which is equivalent to 22 million pure electric vehicles worth of battery capacity in the pipeline. The scale and speed of this growth is unprecedented, and it will have a profound impact on the raw materials that fuel these battery plants. The scale of investment will also drive the cost of lithium-ion battery production down below $100 per kilowatt-hour in this year. This adds extra impetus to this mega trend of battery megafactories and the impacts on the demand for critical battery raw materials of lithium, cobalt, nickel and graphite, have been unprecedented. For example, in the next decade the demand for lithium is set to go up nine times—this is lithium used in the battery industry. Cobalt is set to go up six times, nickel, set to go up five times and graphite anode, set to go up nine times. The question is how much of this mineral to EV battery supply chain does the U.S. control?

So the way I view the battery supply chain is in three main elements: you've got the mine where the minerals come from, you've got the chemical refining aspect which is absolutely key to using those minerals or chemicals in the batteries, and then you've got the battery plants.

For stage one, how much of that mined supply does the U.S. control? For nickel it's zero, for cobalt it's zero, for graphite it's zero, and for lithium it's one percent or something.

For the chemical stage, where the know-how comes in for using these minerals in batteries, how much capacity does the U.S. control? Nickel it's zero percent, cobalt it's zero percent, graphite it's zero percent, and lithium it's seven percent.

Battery capacity stage, where they make the actual batteries, the consuming plants: in 2018 the U.S. had nine percent, that was mainly from the Tesla Gigafactory in Nevada and by 2028 we're only forecasting 10 percent. So we're forecasting a relative flatline as this industry grows.

Incidentally, China is on track to have 65 percent of battery capacity by 2028. It already has 51 percent of lithium chemical capacity, 80 percent of cobalt chemical capacity, 100 percent of graphite anode capacity, and a third of nickel chemical capacity.

Those that control these supply chains will hold the balance of industrial power for the 21st century auto and energy industries.

And the question I have for this Committee is, does the U.S. or—what role does the U.S. want to have in this global energy storage revolution? Because it starts with these supply chains.

I would like to extend my appreciation to Senator Murkowski and the Committee for holding hearings like this because they are vitally important to the industry and the supply chains.

[The prepared statement of Mr. Moores follows:]

BENCHMARK
MINERAL
INTELLIGENCE

Tuesday 5 February 2019

Written Testimony of Simon Moores, Managing Director, Benchmark Mineral Intelligence

For: US Senate Committee on Energy and Natural Resources Committee

Hearing: Tuesday, February 5 2019, at 10:00a.m. Room 366, Dirksen Senate Office Building in Washington, DC.

Subject: Outlook for energy and minerals markets in the 116th Congress.

We are in the midst of a global battery arms race in which the US is presently a bystander.

Since my last testimony only 14 months ago, we have reached a new gear in this energy storage revolution which is now having a profound impact on supply chains and the raw materials that fuel it.

The advent of electric vehicles (EVs) and the emergence of battery energy storage has sparked a wave of lithium ion battery megafactories being built.

Benchmark Mineral Intelligence is now tracking 70 lithium ion battery megafactories under construction across four continents, 46 of which are based in China with only five currently planned for the US. When I gave my last testimony in October 2017, the global total was at 17.

Only one of these battery megafactories is American owned (Gigafactory 1, Tesla). This, however, was the world's biggest battery plant and fourth biggest battery producer in 2018.

Since October 2017, planned lithium ion battery capacity in the pipeline for the period 2019-2028 has risen from 289GWh to 1,549GWh (1.54TWh) in Benchmark Mineral Intelligence's February 2019 Assessment. This expanded capacity is the equivalent of 23-24 million sedan-sized electric vehicles.

This increasing scale will be a contributing factor to pushing lithium ion battery production costs below $100/kWh in 2019, Benchmark Mineral Intelligence data shows. This figure is long seen as a tipping point for the adoption of mass market EVs.

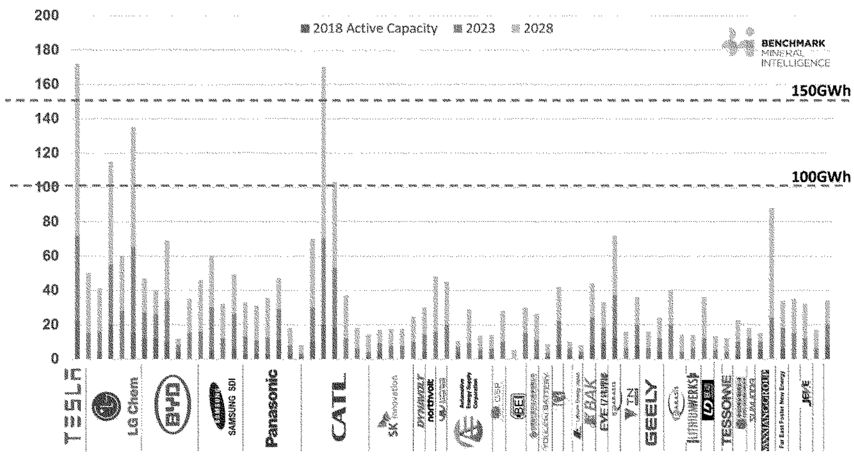
Almost exclusively, these megafactories are being built to make lithium ion battery cells using two chemistries: nickel-cobalt-manganese (NCM) and nickel-cobalt-aluminium (NCA).

This means the supply of lithium, cobalt, nickel and manganese to produce the cathode for these cells, alongside graphite to produce battery anodes, needs to rapidly evolve for the 21st century. However, the scaling up of these chemically engineered materials, which are not commodities, is a major challenge for the industry.

Those who control these critical raw materials and those who possess the manufacturing and processing know how, will hold the balance of industrial power in the 21st century auto and energy storage industries.

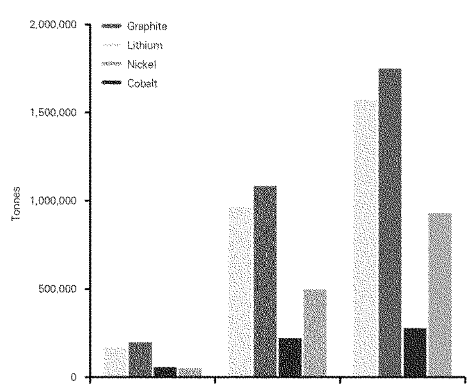
At the beginning of 2019, the US has a minor to non-existent role in most of the key lithium-ion battery raw materials and only has a presence in lithium ion battery manufacturing via Tesla. Tesla and its Gigafactory 1 is emerging to be the most strategic US asset in the EV supply chain.

Chart 1: Build out of lithium ion battery capacity from 2018 to 2028



Source: Benchmark Mineral Intelligence

Chart 2 Lithium ion Battery Megafactory Raw Material Demand (tonnes)at 100% Utilisation Rate



MATERIAL	2017	2023	2028
LITHIUM	162,752	961,351	1,570,020
GRAPHITE ANODE	194,160	1,080,360	1,747,800
COBALT	54,354	219,679	276,401
NICKEL	48,584	494,774	928,018

Source: Benchmark Mineral Intelligence

The growth trajectory expected for lithium ion battery raw material demand is unprecedented.

Lithium ion batteries are becoming a major global industry and the impact on the four key raw materials of lithium, cobalt, nickel and graphite will be profound.

Chart 2 shows the theoretical demand from megafactories in the pipeline at 2023 and 2028. It assumes a 100% utilisation rate where each and every plant is constructed and operated at full planned capacity.

Under this scenario, lithium demand will increase by over eight times, graphite anode by over seven times, nickel by a massive 19 times, and cobalt demand will rise four-fold, which takes into account the industry trend of reducing cobalt usage in a battery.

The real-world expectation is that 70% of this capacity will be realised by 2028 yet even at full capacity this will not yield enough lithium ion batteries for EVs, energy storage and mobile technology.

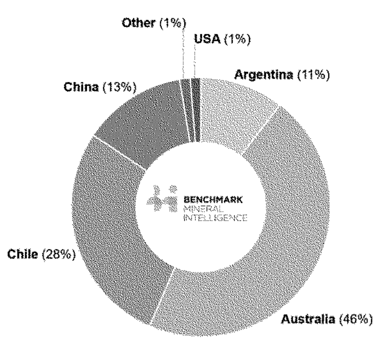
As a result, this global battery megafactory trend will continue.

This would still cause major disruption in the mineral industries supply of lithium ion batteries and the US is heavily import reliant on all four.

Lithium:

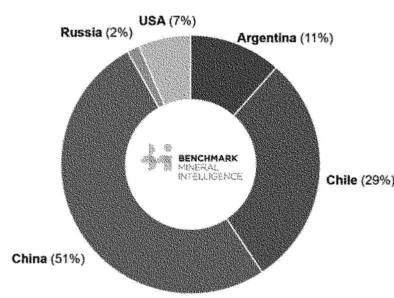
US Lithium Import Dependency in 2018: 92%.

Lithium Raw Material Supply in 2018



Source: Benchmark Mineral Intelligence

Lithium Chemical Supply in 2018



Source: Benchmark Mineral Intelligence

US mineral supply chain influence is greatest in lithium compared with its battery raw material counterparts, but China remains the most influential player in this supply chain.

In the US, there is currently one small lithium operation in Silver Peak, Nevada, but its output is not destined for the EV battery market.

The key US strengths are through lithium producers, Albemarle Corp and Livent Corp.

Albemarle has begun to increase its supply base from an over-reliance on lithium from Chile's Atacama. The EV demand outlook together with a number of political issues in the country has resulted in the company investing $1.15bn on a 50:50 joint venture with Mineral Resources Ltd to build a new lithium feedstock (spodumene) mine and downstream chemical processing facility in Australia.

It is a strategic move by one of the first companies to build spodumene processing capacity that is geared for the lithium ion battery industry outside of China.

This building of the lithium to EV value chain should be happening in the US.

FMC Corp has recently spun out its lithium business into a new company, Livent, to renew its focus on the EV battery market. One would expect this to result in the company increasing its resource base from the Salar de Hombre Muerto in Argentina and to expand its downstream processing capacity.

Despite this activity from US majors, there is yet to be any major domestic plans to build either new mines or major new chemical processing capacity for the EV battery market.

It is also important to note that US lithium producers have been secondary movers when compared to China's lithium majors: Ganfeng Lithium and Tianqi Lithium.

For the past 5 years, both companies have locked up the world's best lithium assets, struck long term supply agreements for EV batteries, and funded a significant portion of lithium's exploration and development cycle, especially in Australia.

A major driver for this is China's lack of high quality domestic lithium resources. US companies have had the opportunity to lock up international lithium resources for the last decade but hesitated while Chinese producers invested.

Domestically, the US still has an opportunity to develop its own supply of lithium from a wide variety of sources including South Arkansas' Smackover (oil field brine), North Carolina's Piedmont (spodumene), Nevada's Silver Peak (continental brine), and California's Salton Sea (geothermal brine).

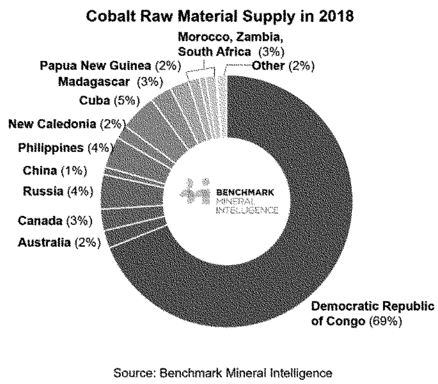
Funding for these new sources has been limited to date as institutional investors seek safe havens for their lithium dollars - Chinese, Australian or South American based companies and assets - rather than the longer-term opportunity which a US domestic supply of lithium brings.

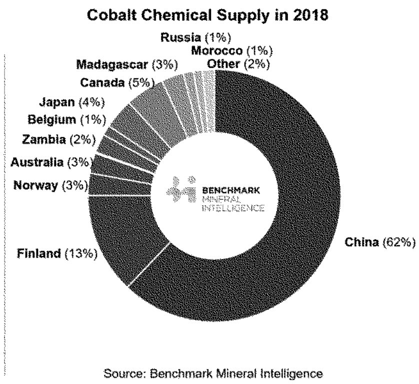
Outside of these typical finance providers, industry stakeholders are another potential funding source: lithium producers, battery makers, and car manufacturers are the most likely candidates. But to date, these major corporations have been risk averse and more concerned about share price and shareholder value than longer-term investments set to benefit the health of the US supply chain.

The rate of funding to build new lithium mines and downstream processing needs to double.

Cobalt:

US Cobalt Import Dependency in 2018: 100%.





Cobalt is a critical safety component of the lithium ion battery, and while auto makers are seeking to reduce their consumption of this mineral, it is our opinion that cobalt will not be engineered out of a lithium ion battery in the foreseeable future.

The US has little control over the cobalt supply chain, either with mining, in which the Democratic Republic of Congo (DRC) is increasing its dominance, or refining, where China holds the balance of power.

The most strategic US asset in the cobalt industry is Freeport Cobalt (owned by Arizona's Freeport McMoRan Inc) which owns the only major cobalt refiner outside of China, but still acquires 100% of its raw material from the DRC – a Chinese run mine that it used to own.

Another factor we do not see changing is the reliance on the DRC as the world's primary source of cobalt - in fact we are seeing DRC supply-side dominance increasing from 64% of global supply in 2017 to 69% in 2018.

While controversy surrounds cobalt from the DRC, and its link to child labour has been well publicised, what is key to understand is that less than 5% of total supply is affected by this. It is, however, a major social responsibility issue for electric vehicle and battery makers to manage.

The world's auto makers are now well versed in the risks the DRC brings, yet at present there is no other option for a large-scale supply of cobalt to come from other countries - new resources will need to be developed.

The US has an opportunity to develop its own domestic supply of cobalt.

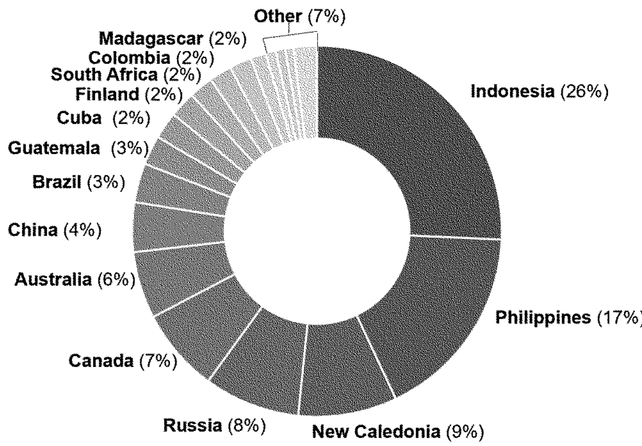
Regions such as the Idaho-cobalt belt, which is globally known as being a cobalt rich jurisdiction, presents one of the few opportunities for US cobalt supply security.

Cobalt remains the highest risk lithium ion battery raw material, both from a supply structure perspective and a geopolitical one.

Nickel:

US Nickel Import Dependency in 2018: 59%

Nickel Raw Material Supply in 2018



Source: USGS

As lithium ion battery manufacturers reduce the amount of cobalt used in battery cells, nickel consumption rises and it does so in a major way.

The move to what the industry calls *high-nickel cathodes* or NCM811 (8 parts nickel, 1 part cobalt, 1 part manganese) is set to put significant pressure on the nickel to EV battery supply chain.

Over 90% of new lithium ion battery capacity in the pipeline is planning to use NCM cathode chemistries, and nearly all new capacity targeting the EV market will use NCM811 and the improved energy density benefits it brings.

This means the 2.2 million tonnes-a-year nickel industry has to re-gear to supply nickel sulphate or mixed nickel-cobalt hydroxide for these battery plants.

Nickel's use in lithium ion batteries accounted for 85,000 tonnes in 2018 yet this was only 4% of total nickel demand. However, nickel demand from EV batteries is set to grow by between 30-40% a year, making it the fastest growing battery raw material.

On the surface, global nickel supply seems fairly evenly spread. Indonesia and the Philippines lead the way with a number of significant producers elsewhere, such as New Caledonia, Russia, Canada and Australia.

However, China is investing heavily in both Indonesia and the Philippines to guarantee its supply of nickel and related products used in the battery industry such as mixed nickel-cobalt hydroxide and nickel sulphide.

In 2019, consumers are turning to new mines under construction in Indonesia that use a high-pressure-acid-leach (HPAL) method to extract nickel. A number of HPAL projects in the past have failed and therefore new nickel supply for the battery industry is far from guaranteed.

Graphite:

US Graphite Import Dependency in 2018: 100%.

While lithium, cobalt and, more recently, nickel have received much of the attention and the bulk of investment in new capacity globally, China has quietly led the way in the expanding graphite industry for the EV market.

This is perhaps unsurprising given that China dominates both the mining and refining side of the flake graphite to anode supply chain.

In 2018, China was responsible for 56% of the world's flake graphite supply – the mined feedstock that is used to manufacturer lithium ion battery anodes.

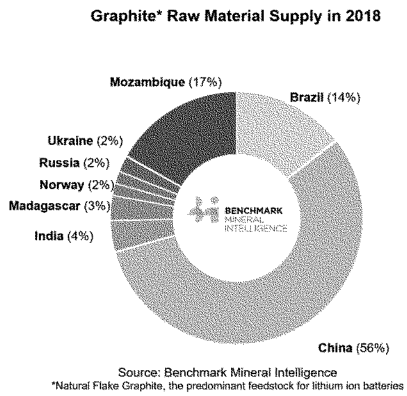
China also accounted for 100% of the world's uncoated spherical graphite supply, which is the processed anode material that is used in lithium ion batteries.

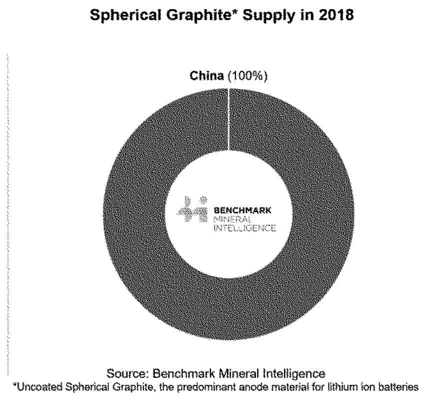
The country's leading producers of anode material – BTR New Energy, Shanshan Technology, and LuiMao Graphite – are leading China's spherical graphite expansions to a cumulative 420,000 to 450,000 tonnes per year by 2020. This four-fold increase is a direct response to China's soaring domestic EV demand.

The US has zero graphite mining or processing capacity geared towards the lithium ion battery industry. While graphite can also be synthetically produced and used in batteries, domestic synthetic graphite expansions have not yet occurred on a significant basis.

The US does not have any active US flake graphite mines nor does it have any capacity to produce anode material from this feedstock. The most strategic US asset in the anode supply chain is German-owned synthetic-producer, SGL Carbon, which has a number of production sites and knowledge bases in Ohio, Pennsylvania, North Carolina and Washington state.

Considering China's position across the entire graphite to EV value chain, secure supply of anode material is as big a risk as cobalt for US to consider.





Source: Benchmark Mineral Intelligence

About Benchmark Mineral Intelligence

Benchmark Mineral Intelligence is the world's leading voice and most trusted provider of independent price assessments for the lithium ion battery and electric vehicle (EV) supply chain.

Benchmark is globally known for setting the lithium industry's reference price which is relied upon to negotiate contracts between actors in the industry, including lithium extraction operators, to cathode manufacturers, battery cell producers and automotive OEMs.

Benchmark's Lithium Price Assessments and analysis is also relied upon by the financial community to aid critical investments into the lithium ion supply chain.

The company also produces regular price assessments on cobalt chemicals and graphite anode and also assesses lithium ion battery megafactory capacity build out.

The EV and battery cell supply chain is Benchmark's sole focus and speciality.

In addition to and wholly separate from its Price Assessment Division, Benchmark also provides lithium forecasting and consultancy services that are relied upon by a wide range of customers from governments, electronics manufacturers, EV makers, battery cell producers, and lithium miners.

To complement its publishing activities, Benchmark has created the industry's leading platform to discuss the subject - *The Benchmark World Tour*. Starting in 2015, the annual series offers free investment and industry seminars, has grown to 15 cities in North America, Europe, Asia and Australia.

Benchmark also hosts an industry gathering for the lithium ion supply chain in November of each year. *Benchmark Minerals Week* consists of two main conference, *Graphite & Anodes* and *Cathodes,* and is the world's meeting place to negotiate deals and network.

Benchmark's price data, insight, and understanding of the subject is unrivalled and culminated in being summoned to the US Senate to testify in 2017 and 2019. In addition, Benchmark has been invited to give guest lectures at the University of Oxford and advise the UK Government.

About Simon Moores

Simon Moores is the world's leading authority on lithium ion battery and energy storage supply chains with a specialist focus on lithium, graphite and cobalt.

Simon is managing director of Benchmark Mineral Intelligence, an independent price assessment and consultancy company for lithium ion battery supply chain and he has gained unique insight into this opaque world since 2006 when he began his career in lithium.

As a result, Simon and Benchmark are cited around the world in international press, official filings and in government research.

In October 2017, Simon was summoned to testify to the US Senate Committee for Energy & Natural Resources in Washington DC as an expert witness on energy storage supply chains. He has also been invited to give regular guest lectures to the University of Oxford and has spoken at Stanford University.

Benchmark Mineral Intelligence has also advised some of the biggest actors in the lithium ion battery space from battery manufacturers, to electric vehicle producers and mining companies, regularly travelling to meet these players across the world from Chile to China.

Benchmark has developed and launched the lithium industry's reference price which is assessed each month by Benchmark Mineral Intelligence, published Bloomberg, Thomson Reuters, and used by the industry to negotiate contracts.

Simon and Benchmark are widely quoted in the global media including China Daily, Financial Times, New York Times, Wall Street Journal, Washington Post, The Times, Bloomberg, Thomson Reuters, The Economist, Chicago Tribune and Fortune.

Benchmark has also advised leading banks such as Goldman Sachs, UBS, CLSA, Deutsche Bank and Bank of America Merrill Lynch and the world's most influential funds.

Benchmark also host three annual events: Cathodes Conference, Graphite + Anodes 2018 and the Benchmark World Tour. These events are the industry's leading platforms for lithium ion supply chain information and deal-making in the supply chain.

Simon has a BSc in Geology with Geography from the University of Birmingham, UK.

The CHAIRMAN. Thank you, Mr. Moores, for reminding us so clearly and directly of the importance of these significant minerals.

Mr. Zindler, welcome.

STATEMENT OF ETHAN ZINDLER, HEAD OF AMERICAS, BLOOMBERGNEF

Mr. ZINDLER. Good morning, Madam Chair, and thanks so much for having me here at the first hearing of the year.

I'm here today in my role as analyst at BloombergNEF (BNEF), a division of financial information provider Bloomberg L.P. Our group provides investors, utilities, oil majors, policymakers, and others with data and insights on the energy world and other sectors of the global economy undergoing rapid transformation.

My remarks today represent my views alone, not the corporate positions of Bloomberg L.P. And, of course, they do not represent investment advice.

As you've all heard, and I very much agree with the panel, how the world has been generating, delivering, and consuming energy are all evolving very, very quickly and radically. These changes have allowed new industries to flourish. The wind and solar sectors, for instance, now employ over 450,000 Americans while over 2.2 million Americans perform work related to energy efficiency. Meanwhile, major capital flows are flowing into the sector. Our firm counted $332 billion invested in new energy technologies in 2018 and have counted over $3 trillion, cumulatively, over the last decade.

We believe that more change, much more change, inevitably lies ahead. In fact, the riskiest bet that investors, utilities, carmakers, oil companies, and even policymakers can make is to assume that the energy world that we live in today is the one that we will have tomorrow.

To take one example, consider how personal transportation is changing and the implications for motor fuels demand. In 2013, pure electric vehicles—that's EVs, not hybrid cars—represented well under one percent of total vehicle sales in the U.S. By the fourth quarter of 2018, they topped four percent. China, which is the world's largest auto market, added 1.1 million EVs in 2018 alone and there are now about 5 million of these cars on the road worldwide. By 2030, we project 1 in 11 cars will be electric and by 2040, 1 in 3.

Growth will be propelled by declines in the cost of lithium-ion batteries, the most expensive components of any EV. Typical battery prices have already dropped 85 percent since 2010. As China, South Korea and others ramp up production, economies of scale will depress prices further. By the mid–2020s, consumers will choose EVs purely based on price, not subsidy like today, and this important crossover could occur sooner if oil prices rise.

We at BNEF are hardly alone in our outlook. The major oil producers have repeatedly raised their own projections for EV sales in recent years. More importantly, Total, BP, Shell, and Chevron have all invested in or outright bought, acquired, vehicle charging companies or even power utilities.

One potential reason: electric transportation will by 2040 subtract 7.5 billion barrels a day of demand for crude products by our estimate. We also think that much more change is inevitable in the power sector driven by cost declines and a move toward "decentralized energy."

Prices for photovoltaic modules (PV)—the solar panels you might put on your roof—have fallen from approximately $4.50 a watt in 2008 to $0.25 a watt as of year-end 2018. For millions of U.S. businesses and homeowners, the decision to "go solar" is being driven by the chance to cut monthly electricity bills or lock in fixed rates for power. I'd also note that PV panels actually function perfectly well in cold weather. By the end of the next decade, solar will be cost competitive in most parts of the U.S. without the benefit of subsidies. PV generation will grow from about three percent today to approximately one-quarter by 2050.

The wind industry can tell a similar story as its generation costs have sunk by more than half since 2009 thanks to more efficient turbines, and we expect that eventually wind will grow to about 14 percent of generation by 2030.

Of course, it's needed to accompany all this as greater penetration of "flexible resources" such as batteries, demand response, and pumped hydro. And along those lines, companies like AES, AEP, Southern California Edison, and Southern Company and others are already deploying large-scale batteries on the grid, or at smaller scale "behind the meter" in homes and businesses.

I'd just like to close with one quick point about energy consumption and its role in climate change, because I would argue that no responsible conversation about energy policy can take place without thinking about CO2 emissions. Last year, U.S. CO2 emissions bucked what had been an 11-year trend generally downward. Instead, they rose 2.5 percent from the prior year, based on our preliminary analysis.

The economy grew much faster in 2018 and that probably played a role. But the year also saw more extremely hot and cold days and, of course, last week we saw the same in 2019 and these appear to have prompted greater use of heating and air conditioning. That, in turn, boosted CO2 emissions. This raises the possibility that as we live with the effects of climate change today, it is becoming more challenging to cut emissions and address climate change tomorrow.

As you can tell, I am fundamentally optimistic about the transformative potential of new energy technologies. But I am under no illusions. The dramatic changes we anticipate over the next three decades will not sufficiently cut CO2 emissions in the U.S. or worldwide to curtail the worst impacts of climate change as detailed by the scientific community. In other words, technology and economics alone cannot save us. New and better policies are needed to accelerate the transition. But that is where policymakers, not energy analysts, must have their say.

And so with that, I'll stop and say thank you, Madam Chair.

[The prepared statement of Mr. Zindler follows:]

Testimony before the
Senate Committee on Energy and Natural Resources
Ethan Zindler
Head of Americas
BloombergNEF
February 5, 2019

Good morning and thank you for this opportunity, Madam Chair and Ranking Member Manchin.

I am here today in my role as analyst at BloombergNEF, a division of financial information provider Bloomberg L.P. Our group provides investors, utilities, oil majors, policy-makers, and others with data and insights on the energy world and other sectors of the global economy undergoing rapid transformation. My remarks today represent my views alone, not the corporate positions of Bloomberg L.P. And of course, they do not represent specific investment advice.

Progress in the energy industry used to be measured in decades. Its scale meant that the adoption of any new technology or fuel was, by definition, slow and laborious.

Today, however, how the world generates, delivers, and consumes energy are all evolving rapidly – and radically.

These changes have allowed new industries to flourish. The wind and solar power sectors now employ over 450,000 Americans while over 2.2 million Americans perform work related to energy efficiency.

Meanwhile, major capital flows are supporting these industries. Our firm counted $332 billion invested worldwide in new energy technologies last year and over $3 trillion in the last decade.

We believe more change – much more change – inevitably lies ahead. In fact, the riskiest bet investors, utilities, carmakers, oil companies, and policy-makers can make is to assume that the energy world we have today is the one we will have tomorrow.

To take one example, consider how personal transportation is changing and the implications for motor fuels demand. In 2013, pure electric vehicles (EVs; not hybrid cars) represented well under 1% of total vehicle sales in the U.S. By the 4th quarter 2018, they topped 4%. China, the world's largest car market, added 1.1 million EVs in 2018.

In all, there are nearly 5 million EVs on roads worldwide today. By 2030, we project one in 11 cars will be electric. By 2040, one in three.

Growth will be propelled by declines in the costs for lithium-ion batteries, the most expensive components in any EV. Typical battery pack prices have already dropped 85% since 2010. As China, South Korea, and others ramp production, economies of scale will depress prices further.

By the mid-2020s, consumers will choose EVs purely based on price – not subsidy – and this important cross-over could occur sooner if oil prices rise.

We at BNEF are hardly alone in our outlook. The major oil producers have repeatedly raised their own projections for EV sales in recent years. More importantly, Total, BP, Shell, and Chevron have all invested in or outright acquired electric vehicle charging companies or power utilities.

One potential reason: electric transportation will by 2040 subtract 7.5 million barrels/day of demand for crude products.

More change is also inevitable in the power sector, driven by cost declines and a move toward “decentralized energy”.

Prices for photovoltaic modules – the solar panels you might put on the roof of your home or business – have fallen from approximately $4.50/Watt in 2008 to about $0.25 as of year-end 2018. For millions of U.S. businesses and homeowners, the decision to “go solar” is being driven by the chance to cut monthly electric bills or lock in fixed rates for power. I’d also note that PV panels function perfectly well in cold weather.

By the end of the next decade, solar will be cost competitive in most parts of the U.S. – without the benefit of subsidies. PV generation will grow from about 3% today to approximately one-quarter by 2050.

The wind industry can tell a similar story as its generation costs have sunk by more than half since 2009 thanks to larger, more efficient turbines. Last year, wind accounted for about 6.5% of U.S. power. While new wind farm completions will likely slow once the current Production Tax Credit phases out, wind’s share of generation should still rise to 14% by 2030, particularly if offshore projects planned off the eastern seaboard come to fruition.

Greater penetration for these technologies must be accompanied by greater deployment of "flexible resources" such as pumped hydro projects, demand response programs, and batteries of various shapes and sizes.

Utility companies, along with a slew of energy-storage start-ups, are starting to respond. AES, AEP, Southern California Edison, and Southern Company among others are deploying large-scale batteries on the grid, or at smaller scale “behind the meter” in homes and businesses.

I'll close with a point about energy consumption and its role in climate change. Because no responsible conversation about energy policy can take place without thinking about CO_2 emissions.

Last year, U.S. emissions bucked what has been an 11-year trend generally downward. Instead, they rose 2.5% economy-wide from the prior year, based on our preliminary analysis of EIA data.

The economy grew much faster in 2018 and that probably played a role. But the year also saw more extremely hot and cold days, which appears to have prompted greater use of heating and air-conditioning. That, in turn, boosted CO_2 emissions.

This raises the possibility that as we live with the effects of climate change today, it is becoming more challenging to cut emissions and address climate change tomorrow.

As you can tell, I am fundamentally optimistic about the transformative potential of new energy technologies. But I am under no illusions.

The dramatic changes we anticipate over the next three decades will not sufficiently cut CO_2 emissions in the U.S. or worldwide to curtail the worst impacts of climate change as detailed by the world's scientific community.

In other words, technology and economics alone cannot save us. New and better policies are needed to accelerate the transition.

But that that is where policy-makers, not energy analysts, must have their say. So with that, I will stop and say thank you again for this invitation.

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The CHAIRMAN. Thank you, Mr. Zindler.

Your comments this morning remind us that what we are talking about this morning is the outlook. I was reading an article from a few days back that was throwing rocks at the EIA analysis and saying, oh, you know, "it underplays how rapidly coal will retreat from the market," "fails to grasp the scale of growth for renewable energy," and "it paints a picture of the future few utilities and energy analysts actually expect to see."

I am just reminded that whenever anybody gets out there and provides an analysis or an outlook, it is what you are dealing with at that moment in time. It is difficult to forecast what changes in policies we may see.

So much of what all of you have outlined on the panel here this morning just reminds us that this is very much forecasting. In the political world we pay attention to those pollsters that we think are usually right and amongst the pollsters they have little side bets, I think, as to who is closest to being right. Maybe we need to do some kind of a pool for our analysts to see how close we got to the mark at the end of the year. But again, recognizing that we have an opportunity at the policy level to help change some of this in ways that, perhaps, we cannot even anticipate.

I wanted to ask about some of the variables that are out there. Obviously there is a great deal of discussion and speculation about the impact of the situation in Venezuela as we are seeing those sanctions there. The impact, clearly, of the Iranian sanctions and how these all factor in.

There have been multiple articles over the past couple days about what it means to our U.S. refineries and our ability here to do the mixing that goes on within our own infrastructure and structure.

So, Dr. Capuano, Mr. Book, if you want to just comment real briefly on some of these external forces. I think you raised the issue—maybe both of you spoke to OPEC and that influence—but you have some really external forces here that are difficult to factor in.

Dr. CAPUANO. We put out our STEO monthly which does adjustments for production changes or shocks to the market. And if you read our last STEO, and our next one will be coming out in the next week, what we see are adjustments. So as production declines in some areas, we're finding that production in the U.S. will increase or production in other locations will increase. So we're finding that while it's disruptive, that there are adjustments that get made. And so, the oil and gas are flowing.

But the question around the refineries gets into fuel mix so, you know, of course Venezuela has a heavy crude. Our refiners use the heavy crude in order to produce products. But there are other sources of heavy crude, for example, from Canada and others.

And so, so far, if you read our STEOs we're seeing that adjustments are being made and while prices are changing modestly, that things are happening.

The CHAIRMAN. Good.

Mr. Book.

Mr. BOOK. Just to amplify what the Administrator said, the heavy crude tends to price at a discount to the light, sweet crude that is the benchmark price you see on TV. And so, when refiners are bidding up for heavy crude, they're essentially buying a lower quality product that requires more processing. That eats into their margins.

It happens to be occurring at a time when gasoline demand is weakening for a variety of reasons, probably some cyclical, some that I mentioned, efficiency-based. And so that's hurting their margins a little bit, having to chase heavy crude around the world where it can be found means a frictional cost.

If the sanctions have an unexpected effect of shutting down production at a far greater rate, then it isn't just a question of Venezuelan barrels not coming to the U.S. but it actually becomes a question of Venezuelan barrels not going into the world. And in that shortfall environment the heavy price goes up still higher and actually you start to see some, sort of, secular move throughout the petroleum pricing structure upward because, in general, there's going to be less product in the world and folks are going to have to bid for it. The effect could still be very modest. There's a lot of dynamism in the system. One of the dynamics is that we have a strategic reserve. It's not perfect for heavy crude but it could add to a volumetric shortfall. The other dynamism is OPEC. The partners that we have in the Middle East are sensitive to our economic situation and sometimes respond.

The CHAIRMAN. Thank you.

Senator Manchin.

Senator MANCHIN. This is going to be an interesting discussion because you all have a unique position in looking at the practical end of what we need to do.

Mr. Moores, on the rare earth minerals, the challenges that we face right now—you kept saying zero, zero, zero, one. We are more dependent on that if we are going to reduce our footprint in the climate arena but not having any, you know, with batteries and storage and things of this sort, of not having control of our destiny. Should we be doing more with the rare earth minerals as far as strategically mining or basically processing them in the U.S. so we have our own reserves?

Mr. MOORES. Yes, that's a good point.

Yeah, I think, I mean, to get U.S. supply security for these supply chains, the answer is simply, yes. The key is to value add, though, and try and build that supply chain within the U.S. So you have the resources but then you have to add on the two or three steps to get to a battery-grade chemical level.

Senator MANCHIN. Sure.

Mr. MOORES. And I think that's the true challenge. But the U.S. does have the resources and in the main has the know-how.

So really, it's got to have the impetus, and right now it's coming from the industry in a stop and start way. They're, kind of, almost waiting on demand to be even bigger and even more in their face than it is now. And so, there needs to be more impetus from, certainly from a government level, I think.

Senator MANCHIN. What I would like to ask—maybe any of you who want to chime in on this—is what is the lowest hanging fruit that you see in the energy arena as far as reducing carbon pollution and being more efficient in what we are using? What is the lowest hanging fruit that we have that you all see?

People make a decision to drive an electric car or not. They make personal decisions instead of taking a practical approach to what really needs to change. What moves India? What moves China? Their demand on using fossil fuels is greater than ever. Their appetite for it is well into 2040, 2050 in all predictions that you, Dr. Capuano, have mentioned.

What is the low hanging fruit and what would drive us to make it more efficient in view of how we pollute, I guess? Kevin, you might want to start——

Mr. BOOK. Sure, I'd be happy to, Senator.

The importance of EVs is easy to overlook when it's such a small part of the base. As Ethan rightly noted, it will be a big part of the long-term picture. But while it is a small part of the base, it also isn't a big part of the solution. Every million electric, light duty vehicles is about 25,000 barrels per day of oil demand destruction, which isn't very much in a 100 million barrel per day world. And right now, particularly in the U.S., consumers of electric vehicles tend to be wealthy and to use them less than typical users of primary cars.

There's been a lot of efficiency gains in buildings and for that matter in industrial infrastructure in response to high prices, but there's a lot more room to be had in efficiency.

Part of the issue——

Senator MANCHIN. That is one of the lowest hanging fruits that you—I mean, we have identified and talked about that also is right there——

Mr. BOOK. Absolutely.

Senator MANCHIN. ——for the picking.

Mr. BOOK. Yes.

Mr. KAVULLA. Maybe, Senator, rather than calling out a particular technology in terms of a regulatory structure, you're seeing the greatest decarbonization trend happening in the states that allow customers to go directly to the market to access sources of clean energy.

So if customers don't have to rely on a utility which has a supply monopoly but can instead execute power purchase agreements or rely on retailers, that's seldom clean energy. You're seeing the greatest decarbonization happen there.

So not a technology but rather a regulatory——

Senator MANCHIN. What is the biggest challenge to that power purchase agreement? If a person wants to produce their own off the grid, then they want to sell back, they have to pay a price to get back in at the grid, correct?

Mr. KAVULLA. That's right——

Senator MANCHIN. That has been the biggest obstacle——

Mr. KAVULLA. That's right.

Senator MANCHIN. ——or challenge we have.

Mr. Zindler?

Mr. ZINDLER. Well just, the panel, both made some great points.

Definitely on the corporate PPA side, or power purchase agreement, we saw a record last year and you see large technology companies, like Microsoft, Google and others, who have giant server farms that they can provide entirely clean energy for. You may have seen the Budweiser advertisement during the Super Bowl—they're bragging about their use of wind power as well. So that trend has definitely been something we've seen going up.

You did mention something about China and I did want to just jump in and say one quick thing about that is that China does everything really big.

Senator MANCHIN. They have to.

Mr. ZINDLER. You're right, they are a consumer of fossil fuels.

They also, as Simon mentioned, they are the largest manufacturer, and soon to be much bigger, and we agree with his research in terms of batteries. And that's because they're actually serving the domestic market. It's the largest market for electric vehicles and they're making a lot of batteries because they're going to sell a lot of them to cars. We don't have that same demand pull here in the United States, at least not yet.

Senator MANCHIN. Doctor, do you have any input on that?

Dr. CAPUANO. Well, when you look at—I think the low hanging fruit is gone but if you look at our graphs, and we've submitted some of these, you'll see that through technology investment and policy combined, we have been driving down the carbon intensity both of the grid, transportation and residential.

And I think the very encouraging piece of data is that as you get out toward the next 10 or 20 years as our reference case, which is the base case to refer from, where you see the rolling off of policies, the investments in technology combined with the polices have allowed costs to come down so that you see that solar and wind, for example, are economically competitive and continue to grow at a slower rate.

So the expectation is there will be more policy, but our reference case shows that there have been some successes now and that that's very encouraging. And the same thing in residential, it's, you know, we're seeing the shifts in demographics in terms of where people live, houses are getting bigger, and so, as a result the per square foot energy efficiency may be going down but the square footage is increasing. And so, again, more investments and more encouraging policies would reduce the energy intensity.

There's no magic, I guess.

Senator MANCHIN. I know that. Thank you.

The CHAIRMAN. Thank you, Senator Manchin.

Senator Barrasso.

Senator BARRASSO. Thank you, Madam Chairman.

Several months ago, the U.S. became an energy exporter for the first time in half a century. According to projections, the U.S. is going to be a consistent energy exporter by 2020. To achieve this and ensure reliable, long-term energy supply to our allies, I think we need to build out the infrastructure to transport and export our energy sources.

Dr. Capuano, do the EIA's projections consider expanded export infrastructure, including additional LNG export terminals and expanded pipeline networks?

Dr. CAPUANO. Yes, LNG terminals and pipeline networks are included as they become approved or are getting very close to execution. They're included in our models.

Senator BARRASSO. And are there things that Congress can do to ensure that the United States maintains the title of energy exporter into the future, basically energy being the master resource that it is and our role in the world?

Dr. CAPUANO. Pardon me, I didn't quite get that?

Senator BARRASSO. What are the things that Congress can do, I think, as a fact of energy being the master resource because it is a force multiplier? It could be used in so many ways as other countries use it as a weapon, as Putin has done. Are there things that Congress could do?

Dr. CAPUANO. Yeah, I think the EIA data shows that policies have had an effect, because as they roll away you see changes. And so, I think that data can be used to help support your conversations about what kind of policies to execute.

And again, EIA would be very happy to provide more details from our data. We publish our data but help explain the data in more detail.

Senator BARRASSO. Thank you.

Mr. Kavulla, in your written testimony you note that states can sometimes unilaterally frustrate multistate energy projects. You highlight the millennium bulk export terminal as an example. In this case the State of Washington blocked construction of a coal export terminal that would ship Powder River Basin coal, much of it mined in my state, to Asian markets. We have it, the United States has it, Asian markets want to purchase it.

How can states work together to ensure that the success of American energy is not threatened by a conflict between the states, because that is what we have going on right now with Washington State and its blockage of something that is a U.S. export that others want to buy and are happy to pay for but one state is unilaterally blind.

Mr. KAVULLA. Senator Barrasso, I think a good way to think about this is to consider those situations that you've just identified, where a state's energy policy is preconditioned or antecedent on a particular type of infrastructure which can be frustrated by another state, say by exercises of their Clean Water Act authorities. Trying to find those situations where those blockades can occur, whether it be on export terminals or electric transmission or natural gas pipelines, and then find a way for Congress to intervene or states to work together.

Congress has previously tried to do that for electric transmission by building in shock clocks. The Federal Communications Commission does this for communications infrastructure siting, but sadly, there's a real lack of parallels to that that have really stuck in the federal courts based on their interpretations for energy infrastructure.

But I think the framing that you've put on it is correct. It's really, it's become a state versus state conflict which seems to require some kind of federal oversight for intervention. And it will ultimately hamper not just the development of coal exports but even renewable electricity from interior states that have robust renewable resources.

Senator BARRASSO. Thank you very much.

Thank you, Madam Chairman.

The CHAIRMAN. Thank you, Senator.

Senator Heinrich.

Senator HEINRICH. Madam Chair, I know you know that I am reticent to differ with you, given your expertise on these issues, but with regard to this particular issue you said it is kind of like forecasting. I want to suggest that predictive analytics should not be about forecasting. It should be about modeling, and we should be asking about these models and what goes into them and how that impacts what comes out of them, and then comparing what comes out of them to the patterns that we actually see in the industry.

I have long been incredibly concerned with the wild inaccuracies in EIA's projections in the electric power sector and the failure to factor in the trends and technology to lead, not only to lower generation, to lower cost generation, but also early retirements of uneconomic generation. And year after year, we have seen EIA spectacularly estimate, underestimate, growth in renewable energy and gas generation, and this year's version seems to be no better, frankly.

For example, the idea that coal will still provide 17 percent of electric power in 2050, I think for most people in the industry today, is not credible. We have no new coal plants that are planned. Existing plants will be well past their useful lifetime. We are shutting down plants in my region of the country. I see similar trends in other regions of the country. So, more fundamentally, is it time, Dr. Capuano, to revisit your underlying model?

Dr. CAPUANO. So I would point out that we do something that no one else does in the United States or, I think, globally, is we do a base case. It's a reference case. It tells you what will happen if nothing changes. That is not a forecast of where things will go. It's not trying to do a probability of where things are going.

Senator HEINRICH. But is that useful?

Dr. CAPUANO. It is useful.

Senator HEINRICH. Because we all know that——

Dr. CAPUANO. I would hope that it would be.

Senator HEINRICH. ——change is the only thing that we can truly rely on.

Dr. CAPUANO. I would hope it would be useful to help you understand how much work has to be done to get to where you want to go. So where else do you go to find out how impactful your policies are or whether your policies are being effective or what happens if they go away?

Aspirational or visionary models or statistical or probability models of what's the probability it's going to happen are rampant, and they are very useful but no one else does one that says this is what happens if everything stays the same.

Senator HEINRICH. I think my challenge is that for the vast majority of businesses, as well as the public, most people don't understand that there is a reference case or what that even means.

So they look at examples such as wind energy, and in this model you see almost no additional capacity either onshore or offshore after 2022. And yet, we look around at what is going on right now and you have the Department of the Interior awarding wind leases for up to four gigawatts off the Massachusetts coast in the last few weeks. You have New Jersey planning a gigawatt. You have Virginia planning multiple gigawatts. You have New York announcing a wind target of nine gigawatts. And you look at the testimony today from Mr. Zindler who suggests that wind power is probably going to grow from 6.5 percent of generation to 14 percent of generation by 2020 which is roughly double your base case estimation.

And if people see that, I don't know that this is a useful exercise for us to go through when the base case is so far removed from reality, especially given the fact that many people will look at that and they will make business decisions about where to place bets, where to invest, based on a misinterpretation of a model.

Ms. CAPUANO. Thank you.

Senator HEINRICH. Mr. Zindler, let me go to you.

How do your clients at Bloomberg New Energy Finance view EIA's Annual Energy Outlook in terms of its usefulness for making business decisions?

Mr. ZINDLER. Well, let me try and be diplomatic here and just say that——

[Laughter.]

——first of all, as was noted, making predictions is hard as Yogi Berra once said much more artfully than I just did. And we, as a firm, have been forecasting the price of solar for 10 years and we've been much more aggressive in our projections of how fast prices will come down and how fast adoption will pick up. And we have been consistently wrong on the low side.

Senator HEINRICH. On the low side.

Mr. ZINDLER. Right.

So, it's hard to do. I just want, sort of, to preface that.

The second point I would make is that with well respect, we actually, our forecast, we do think is actually, is policy neutral. We assume policies sunset. Well, for instance, we don't assume that production tax credit sticks around forever.

And third, small correction, which is that we think that wind gets to about 14 percent by 2030, not by 2020.

Senator HEINRICH. Yes. My mistake, not yours.

Mr. ZINDLER. But to your question, I think the short answer is, it is the EIA, yes, has been a source of frustration to those in the clean energy sector for a long time and, I think increasingly, in the conventional energy sector as well.

We forecast coal doesn't disappear by the way. We think it does eventually drop to about 10 percent of generation but not 17 percent.

Senator HEINRICH. Thank you, Madam Chair.

The CHAIRMAN. Thank you, Senator Heinrich.

I can take that. It is okay. We are going to be just fine this Congress.

Senator Cortez Masto.

Senator CORTEZ MASTO. Thank you. Thank you, Madam Chair and thank you and welcome to the new Ranking Member. I look forward to working with this Committee.

Let me open this up to the panelists. One thing I am very excited about which has been brought up, specifically in Mr. Simon's testimony, is the recent rise in the use of electric vehicles. Last year there were, I think, about 361,000 electric cars sold, which is up 81 percent over 2017.

But despite this exciting growth, Dr. Capuano notes in her testimony that assuming no further policy action, the plateauing of fuel efficiency gains in 2027 is projected to result in increasing consumption of motor gasoline after that time.

I think we need a broader national outlook and strategy to increase the adoption of zero emission vehicles to ensure we can compete with countries like China and the EU.

So my question for the panelists is, what are some challenges with differing state by state approaches to energy markets and regulation that need to be overcome to help develop a consistent national framework for integrating electric vehicles and their infrastructure into our energy system?

I don't know where we would like to start, if anybody has comments on that or can provide enlightenment on this?

Mr. KAVULLA. I can start on the regulatory framework because I'm a former public utility commissioner (PUC); you're right that it's all over the map with PUCs.

Some PUCs have regarded their regulated utilities as central investors in electric vehicle charging infrastructure, something that would go in rate base, be paid for by their captive set of customers. Other people favor a more liberalized model of electric vehicle charging stations. That's a policy debate that right now is being resolved on a state by state level. Obviously, if we hope to have nationwide deployment of electric vehicles and across state transport with electric vehicles, much will depend on how that question is resolved in the state level.

Senator CORTEZ MASTO. Right.

Mr. KAVULLA. And I think other people would probably have something to say about the technical aspects.

Senator CORTEZ MASTO. Anyone else?

Mr. BOOK. I would just say that there's, when you look at EV penetration, there's a lot of factors to consider. The hardware cost is higher. The variable cost is lower. So, the average cost will start to become very competitive with conventional vehicles when the hardware cost converges to the cost of conventional vehicles.

One of the things that changes those is the variable cost of those conventional vehicles. The more efficient internal combustion engines get the more it pushes back that organic break-even point. The reason that's important is that part of the policy question you're asking is theoretical in nature right now and it will become a panic when it stops being. The curve doesn't go gently upward. It hits a kink and then it rockets off the page. There's essentially a point where the economic proposition dominates and consumer choice probably takes us into a very different vehicle mix. And so, not having policy set ahead of that time can be problematic, but setting the wrong policy ahead of time is also problematic.

Senator CORTEZ MASTO. Right.

Mr. BOOK. So you don't want to get too far ahead of it.

Senator CORTEZ MASTO. Are there things we should be doing at a federal level to help address this or take a look at this and plan for the long-term?

Mr. ZINDLER. I mean, I'm not quite sure I know enough about the law to know how you could intervene on some of these state questions. But to me, one of the interesting ones to your original question is who gets to sell electricity?

You know, certain states it's very heavily regulated about who can actually have those responsibilities. And you know, we're going to need a lot more charging infrastructure and it would sure be nice to be able to charge my electric vehicle at Starbucks every time I went there or where ever that is, you know, where I spend a logical half hour, you know, every week or two. So, there's not always the freedom to do that kind of thing.

To Kevin's point also, I would just agree that there's a lot of ways to look at what the economic crossover point will be and in a perfectly logical, economic world, the consumer would look at the sticker price of the vehicle, do the math of how much gasoline they might have to buy, do the math on how much electricity they'd have to buy. Net that all out and then, you know, make a decision.

We tend to think consumers are just more likely, like Kevin said, the moment they walk into the showroom and the EV is cheaper, then they'll buy it. And that's probably what will influence behavior going forward.

Mr. KAVULLA. One very concrete idea for you, Senator, would be and it's somewhere where the federal Congress would be involved is the prohibition on any commercial activity or most commercial activity at federal highway rest stops. Obviously, the introduction of electric vehicle charging stations there could facilitate some of the cross-state aspirations of drivers. Right now, they face an impediment because of that prohibition.

It's something my R Street colleagues and I have been working on, and I'd be happy to follow up with you.

Senator CORTEZ MASTO. Thank you.

Thank you to the panelists. I notice my time is up.

Thank you.

The CHAIRMAN. Thank you.

I understand Senator Cassidy is going to defer to Senator King?

Senator CASSIDY. He owes me his first-born child.

[Laughter.]

Senator King, it is up to you.

[Laughter.]

Senator KING. Thank you, Senator, I appreciate it.

We are talking about a lot of the studies about exports and imports. We are now exporting a great deal more. Do you have any data on exports of natural gas and where that has gone? There has been a lot of talk in the last two or three years; are those LNG facilities actually being built and are they exporting and, of course, what I am interested in, in the long run, is will those exports reach a point where they will have an effect on domestic prices?

Dr. CAPUANO. So you're asking what's happening with the——so in my opening remarks I did——

Senator KING. We know oil is being exported. Is natural gas being exported in a substantial——

Dr. CAPUANO. Yeah, yeah.

So in my opening remarks I did comment on the fact that natural gas—let's see, where are they?

Senator KING. I apologize.

Dr. CAPUANO. Yeah, that's okay.

So, that same developments in domestic shale and natural gas resources have enabled the U.S. to emerge as a net exporter of natural gas. The total natural gas exports from the U.S. exceeded imports and our production is at an all-time high of 30 trillion cubic feet in 2018. And we project that it will grow, initially, by seven percent per year and then slow to one percent per year after 2020.

And so, we now are seeing an increase in both pipeline and liquefied natural gas and there are going to be more facilities built.

Senator KING. What I would like to urge you to do in your data collection is to integrate those projections with price projections.

My concern is that we start to export and reach a point where supply is tighter and domestic prices go up. So perhaps that is something we could follow up later.

Dr. CAPUANO. Yes, we can follow up with you when we do address that in some of our projections. What we're seeing is that production, as the prices go up, production will increase and so, we do not see a lot of that.

But yes, we have more details that we can provide to you, yes.

Senator KING. I would appreciate that. Thank you.

[The information referred to follows:]

SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

Dr. Linda Capuano

Dr. Capuano's February 5, 2019 testimony

Response to Sen. King's Question: In EIA's Annual Energy Outlook for 2019, we provided integrated forecasts of production, imports, and exports of natural gas in the United States for both a Reference case, and a case where we effectively doubled world oil prices as a way of exploring high international demand. While sensitive to increasing U.S. natural gas exports, these EIA forecasts do not indicate that increased exports pose significant, long-term upward pressure on prices, given the potential for increasing production.

Under our Reference case, exports of natural gas net of imports grow continuously by almost 160% between 2020 and 2050, with prices that grow gradually in real (2018) terms from about $3.00/MMBtu in 2020 to less than $5.00 per MMBtu in 2050. By 2050, the Reference case projects that net U.S. exports of natural gas would represent almost one-fifth of U.S. production. In the high international oil price case, net natural gas exports grow by almost 320% between 2020 and 2050, with prices reaching almost $5.50/MMBtu (in 2018 dollars) in 2050. In this case, net U.S. exports of natural gas represent more than a quarter of U.S. production. Projected domestic natural gas production in the high oil price case is 10% higher than in the Reference case in 2050.

Recent, admittedly short-term experience reinforces the notion that significant expansions of U.S. natural gas exports have not resulted in significant upward pressure on natural gas prices. Starting in 2017, the United States began exporting more natural gas than it imported. Prior to that, the United States had routinely been a natural gas importer throughout EIA's records starting in 1973. In the summer of 2019, net monthly natural gas exports reached significant levels, almost 6% of U.S. production. At the same time, average summer benchmark Henry Hub prices (June through August) in the United States averaged $0.40 lower than any other year in the 21st century.

Senator KING. Mr. Moores, we were talking about raw materials components. In your testimony you talked about the greater demand. Are we adequately prepared for a rapid transition to greater electrification which is going to require more of these battery materials?

Mr. MOORES. Yes, quite simply.

Senator KING. I mean, are we prepared for it, do you think?

Mr. MOORES. No, sorry, you are not prepared for it.

Senator KING. I was surprised.

[Laughter.]

Mr. MOORES. No, no.

You have the ingredients, the raw material, the know-how, but there's just no impetus to link that all together in the moment. There's no encouragement of converted integration in the supply chain from the mine to the lithium-ion battery plants. So, yeah.

Senator KING. Do you foresee a bottleneck here as electrification increases, that the minerals for the batteries will be a bottleneck?

Mr. MOORES. Yes, globally actually, not just for the U.S. but the U.S. has zero of these raw materials, almost zero of these raw materials actually being mined at the moment. So——

Senator KING. That is obviously a concern I think we have to be thinking about so we are not cutting off a promising development.

On the question of electric vehicles, one of the things that has always occurred to me is that when will most—I am asking a question. When will most people charge their cars? At night.

The grid is grossly inefficient in the sense that it has great excess capacity at night. We have excess generating capacity at night. It seems to me one of the keys to this would be time-of-day pricing to make it even more economically advantageous and to benefit all ratepayers, because the grid doesn't need much in the way of additional wires and poles to accommodate this if we come in at night when there is so much excess capacity.

What are your thoughts about that as a former state regulator?

Mr. KAVULLA. I absolutely agree. I mean, we're not sending——

Senator KING. That's great. I like that.

Mr. KAVULLA. Yeah, we're not sending efficient price signals in general to consumers, only——

Senator KING. I mean, power at night has no value, almost.

Mr. KAVULLA. That's right. And the fact is we were talking earlier about the cold last week. Retail customers were paying the same retail rates when it was cold and the system was stressed as they will when the system has tons of surplus capacity.

There's good policy reasons and equitable considerations to make sure that retail customers don't experience volatile price spikes, but there is some good sense in trying to send signals to certain customers that could have their own cars or homes act as resources to help balance the system and provide reliability. And time of use pricing gets you there.

Senator KING. You are singing my song, distributed energy, more self-healing grid, national security, all of those things.

I am old enough to remember when phone rates went down at 9 p.m. and people sat around and watched their watch and when it crossed 9 p.m., you called mom. People will adjust their behavior given the proper price signals.

And right now, at least in most places in the electrical sector, those signals do not exist.

Sir? Mr. Zindler?

Mr. ZINDLER. Can I just add a real quick thing which is, I wholeheartedly agree although I will add one other point which is that I think actually, a lot of electric vehicle charging will take place overnight anyway. I mean, I've had an EV in my garage for five years and I think we've used a public charging station about two or three times because we can just literally plug it in the wall when we go to bed. We all sleep. It's a good time to charge your car.

So, yeah, you could incentivize it and I think that's a great idea. It definitely helps.

Senator KING. I wouldn't call it an incentive. I would call it rational economic pricing.

Mr. ZINDLER. Agreed, totally—it may not help, but I think the consumers will trend that way anyway which is a good thing as long as they have a garage. That's a big asterisk there.

Senator KING. I have an EV and don't have a garage, so I have to pay the Senate an arm and leg to charge it here at the garage.

[Laughter.]

Thank you, Madam Chair.

The CHAIRMAN. I don't know, Senator King, what does it say about those of us that still wait until after 9 p.m. to make that telephone call?

[Laughter.]

Senator KING. Those price signals stick with us, Madam Chair.

The CHAIRMAN. They do. They do.

But I am on Alaska time too.

Senator Cassidy.

Senator CASSIDY. It could mean you don't want to call your mother, but that is another issue.

Thank you all, great testimony.

Dr. Capuano, there has been a lot of discussion regarding the increased use of renewables but as I understand, the physics of our current technology, kind of, top out as to the efficiency both the wind turbines and the ability of the batteries to store energy and that these are immutable, if you will, there are laws of physics which in turn will top out the contribution that renewables can make to an overall energy mix.

I think I know that IEA has, kind of, begun to taper off the growth in renewables as a mix of U.S. economy.

Any comments on that? Would you agree, disagree?

Dr. CAPUANO. So when you look at the EIA projections out to 2050, what you're seeing is the roll off of policies that are causing the slow down and the renewables are being absorbed into the grid.

And so, that obviously, there are mechanisms that can change that.

You're not seeing that the physics limits are not causing the slow down out to 2050. And I, you know, the investments in technology are causing improvements and cost reductions. And so, out to 2050 we're not seeing those limits.

Senator CASSIDY. But let me, kind of, quote here and I just say that because obviously for increased use of renewables there will have to be substantially increase in efficiency, not marginal, not going up 6 percent or even 10 percent, but rather 50 percent, if you will or more deployment. But I am also told that, for example, where wind is deployed the choicest places have been filled, if you will.

So, let's see if I have it right here. Of course, if I look for it, I won't find it.

Oh well, that the, suffice it to say, well for example here for the batteries. "The physics of using silicon to convert photons into electrons ends at about 33 percent conversion called the Shockley-Queisser Limit. The most recent announcement of high efficient silicon sells with 26 percent efficiency are approaching the limit. More efficiency is possible but no tenfold gains left." This is out of the Manhattan Institute.

Would you dispute that or kind of acknowledge it and say maybe we will find something else to do?

Dr. CAPUANO. So, EIA is not really the technology end of the DOE. So if I can get you from DOE the answers to where these physical limits are, but since we're doing, we do modeling of the energy production, energy consumption and we're not hitting those limits, we do, definitely, put technology improvements into our models.

[The information referred to follows:]

SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

Dr. Linda Capuano

Dr. Capuano's February 5, 2019 testimony

Response to Sen. Cassidy's Question: After exploring with the appropriate, knowledgeable staff within the Office of Energy Efficiency and Renewable Energy within the Department of Energy, I have identified their position on your question about physical limits of renewables as explained in the following quotation:

"The Department of Energy acknowledges The Manhattan Institute's observation without endorsing whether it's correct or incorrect. The Department continues to support research and development of new technologies for alternative energy sources. While higher efficiencies are the desired outcome results are contingent, especially for renewable energy technologies, on multiple factors. In order to accommodate high-quality renewable resources transmission and other infrastructure must be developed. EERE is also studying various ways to increase efficiency including repowering existing sites, technology improvements, etc."

"Enabling the rapid growth of solar photovoltaics (PV) does not require tenfold increases in efficiency; increases of several percent can have a significant impact on the cost of solar electricity. DOE research programs and those around the world are working to increase the performance-to-cost ratio of PV in three ways - increasing efficiency, reducing manufacturing costs, and extending the usable lifetime of the system - all of which can reduce the levelized cost of solar ($/kWh)."

Senator CASSIDY. Okay.

Dr. CAPUANO. Okay.

Senator CASSIDY. But you rely upon others to say what those technology improvements have the potential to deliver? That is fine. That is fine.

Mr. Book, I really liked your testimony because I think that we oftentimes divorce emissions from carbon intensity and from GDP growth. We can lower emissions if we go back to a stone age economy, but most do not wish to do that. And so, I like your pointing out that over the last period of time we have actually decreased in several sectors the energy intensity by about 20 percent.

You also point out that India and China are going in a different direction. Is that inherent as to the state of their economy relative to ours or could they also begin accomplishing some of that which we have accomplished?

Mr. BOOK. Well, Senator, their energy intensities are also falling largely, but they're falling from a much higher place and not always at the same slope.

From the perspective of whether they're doing better or worse, they're doing a lot worse from an economic perspective. So, that energy intensity that they face is more of an economic problem for them because per capita incomes are lower.

So, we really have it good two ways, right? We're more efficient users with higher per capita incomes.

I think also just to your prior question, I sense that your question is about the physical limits and I think the Administrator's point was that that's not what's breaking the model.

One of the things though is that energy has tradeoffs. So we don't necessarily buy the 33 percent efficient solar panels, and there's barely any that I think that have ever been made. The highest are in the high 20s. We mostly buy them in the teens, and it takes a lot more space as a result.

So the tradeoff when you have energy that is renewable is often that you're going to have to use more space or there's other aspects of renewable energy that, just like conventional energy, there's a downside that comes with the upside. And one of the things that's hard to see when you're at a small penetration level is what that downside is like. But as we get to a higher penetration level, long before we're stopped by those physical limits, we run into real problems. And these are some of the problems that you can see in developments where environmental challenges against solar arrays in the desert because of biodiversity concerns are showing up. That's what it's like to be big time. And so, there are definitely other factors that create drag on some of the projected growth rates.

Senator CASSIDY. I am out of time. I agree with you. I am all for renewables, but I do think we have to be sensible if we are going to promote economic growth which obviously requires energy. So again, I thank you for your testimony.

I am out of time. It is the deference of this.

The CHAIRMAN. Go ahead.

Mr. ZINDLER. Let me just jump in real quick on solar.

Just first, I don't think the numbers you quote are wrong in terms of the efficiencies and the 33 percent cell is probably what you'd find on a NASA, you know, space mobile. As Kevin says that we're looking more like 19, 20 percent.

But very importantly, I think it's important to understand and acknowledge what's going on with batteries right now because the price of batteries has absolutely collapsed in the last seven or eight years. And we forecast that they will continue to decline very rapidly. And that's not because I have some sort of Messianic religious belief in technology, it's because China is about to swamp the market again with battery manufacturing. That's going to push prices down.

And if you look at some of the bids to provide power on a more round the clock basis in places like Arizona and, most recently, in Hawaii, the cost and the bids that are coming in are very, very low for solar plus storage.

I think, to be clear, that's being subsidized with a federal tax credit which is helping to depress those prices but it's getting much cheaper. And we view that crossover as coming, for sure.

So you're right, the system is limited in how much you can just throw a ton of solar on, but eventually we'll have enough storage to help address that.

Senator CASSIDY. But going back to Mr. Book's point, that will be a lot of space for that storage.

Mr. ZINDLER. Batteries are, by comparison to the acres that you need for photovoltaic panels, batteries are relatively small.

Senator CASSIDY. Thank you.

The CHAIRMAN. Thank you.

Senator KING. Madam Chair?

Senator Cassidy, one thing you mentioned about wind, the choicest places have been filled and to some extent that is true on land, but there is a gigantic, untapped potential for wind offshore. That is—it dwarfs what is on the land. The wind blows, the efficiency, the capacity factor is higher. So I just want to point that out that we've done a lot on land, but offshore is where the future is, I think, in terms of really large scale.

Senator CASSIDY. Which is why, Senator King, Senators Murkowski and Cassidy want you to get on our revenue sharing bills.

[Laughter.]

Senator KING. So we can share some of those revenues from those wind turbines.

The CHAIRMAN. That's exactly right.

[Laughter.]

Exactly right.

Senator Hyde-Smith.

Senator HYDE-SMITH. [off-mic]—serving on this Committee, and I look forward to working with you and think good things will happen. Thank you.

The CHAIRMAN. Thank you, Senator Hyde-Smith. Again, we welcome you to the Committee and look forward to your engagement.

Talking about those policy changes that we can actually see are coming. Some of them are a little bit speculative, but we know that at the end of this year we have a regulation coming at us from the International Maritime Organization, IMO. This is this IMO 2020. It is going to go in effect overnight. On the 31st it is business as usual, and on the first we switch over to a further capping of the amount of sulphur that is allowed in marine fuel. It is a pretty significant drop down with the cap, down to 0.5 percent from 3.5 percent that it is now. So this is significant. We know that it is going to produce some real positive benefits.

I have been talking to some of the U.S. refiners who have been working to incorporate this and they have made the investments based on these regulations that they know are coming at us. But give me your, again, your assessment and this is directed to you, Dr. Capuano and Mr. Book, the best estimate for what this shift is going to mean for the middle distillate market and the impact on pricing for diesel for jet fuel and recognizing that we are leading up to this as well.

I am assuming this is all factored.

Dr. CAPUANO. Well, you actually pointed out that the United States' refiners have been positioning. We have many complex refiners who deal with heavy, sour crude and we also have balancing crude here in the U.S., light and sweet. So not only do they, would they put them through the crackers but they could also do blending.

So the refiners, in general as a class, the refiners are able to accommodate this. There, of course, is a big shifting at the global level in terms of the flow of fuel since the location and the bunkers that will have the lower sulphur fuel will be in different, you know, different places. And so, things will have to be moved around at a different rate.

And so, I'm going to leave it to you——

[Laughter.]

The CHAIRMAN. What is going to happen to the prices? That is what people want to know.

Dr. CAPUANO. Yeah.

Mr. BOOK. Okay, well, you know, with the, I think the important caveat that Senator Heinrich established that models tend to be fraught with peril, particularly the further you go.

We just yesterday published a projection of a range between 9 and 26 percent diesel increases for perhaps a short-term with a central tendency around 21 percent.

The CHAIRMAN. But during what time period? Beginning this year or next year?

Mr. BOOK. So, then that's the key question really. There's a couple of factors. One is compliance rates. The second, of course, is government intervention and if there's an agreement to push things back. But right now, we expect the adoption to begin well before the first and probably by 3Q.

The CHAIRMAN. Because this is not just adoption by the United States.

Mr. BOOK. No, no, no, no, no.

The CHAIRMAN. This is actually globally. So it is a big market.

Mr. BOOK. And it takes a while for these big ships to clean out their tanks and to test out new fuels.

And so, some of the stress that we could see will start to emerge, probably if there is stress, in the third and fourth quarters ahead of the cutover.

By the time things start to normalize, there's a lot of offsetting factors. One is the ships can steam slower. They can be more fuel efficient. There's truly people who could choose to disobey the law, although we think compliance is probably, you know, 70 to 80 percent, globally.

But in addition, there's also the call on distillate. You can run refineries harder. And when you run refineries harder, you start to get to less of a shortfall. So the volumetric shortfalls, marine bunker fuels are roughly 3–3.5 million barrels of consumption a day. And the shortfall could be somewhere in the half million range in the most, sort of, beneficial workout for a short period of time while the transition continues. It might be as much as 1.5.

And so, there's a lot of factors that determine it. We're thinking it's going to be closer to, sort of, about the one million barrel per day. And that exerts a price effect, probably. Without that price effect, though, you don't get further transitions in the refining kit around the world to make the conversion.

So it's a complicated problem. And in essence, as you say, there is an environmental signature to doing this. Here in the U.S. and in Europe we're already at a much lower sulphur level in our environmental regulations in coastal areas as it is.

The CHAIRMAN. I am just very keenly aware that even with a looming deadline, sometimes you have the view or the attitude that well, we will just push that deadline off. Well, we are not quite ready for it.

I think it is important to recognize that, again, this is not just something that Congress or the Administration has laid down. This is an international maritime agreement, if you will, in terms of these regulations. How we are teed up to abide by that and not to be shocked when we see this change come into place is something that we need to start paying attention to.

Senator Manchin.

Senator MANCHIN. On the refineries, I just need to ask the question. Even with the refineries that we have in the United States today and our newfound position as far as crude production, we are still importing, correct? Is that because of the refinery capacity, the type of refineries we have, or because we have not been able to make the adjustments, or are they making the adjustments since we have——

Mr. BOOK. It's not a question of not able to make. It's a question of optimizing. So, to make the most money here at home, create the most jobs here at home.

What they're doing is they're set up so that they can bring in imported crudes at a lower price, heavier, sourer crudes, process them, mix them with their light. They are definitely tooling up to use more light oil and expanding capacity here in the U.S., but the continued use of heavy crudes as to enable them to make more profitable products across the slate.

Senator MANCHIN. Sure.

Mr. BOOK. So we will continue to import those heavy crude.

Senator MANCHIN. For economic purposes?

Mr. BOOK. Yes.

Senator MANCHIN. But not for strategic——

Mr. BOOK. Well, if you want to count barrels that have the net balance be zero, we're going to get to that point by their projection at the end of the next year, potentially. But in terms of zeroing out total gross import flows, that's not really in our economic interest.

Senator MANCHIN. Gotcha.

Mr. BOOK. We want to make the most money, create the most jobs.

Senator MANCHIN. The current nuclear fleet faces severe economic challenges in today's market. Since 2013 five nuclear plants have closed, and six plants are scheduled to shut down by 2025 due to economic challenges.

Some states have been able to prevent shutdowns with state policies like zero emission credits. Even with this assistance, the high price tags of nuclear plants and high operating cost have put a great deal of financial strain on nuclear plants.

It appears to me that in order to harness the benefits of nuclear power as well as expand in this space, we must ensure that the Department of Energy is developing the technology and partnership with the private sector to lower the cost for the current fleet and develop the next generation of nuclear technology.

So I think, Mr. Book, this question might be to you. How can we better direct federal dollars to ensure the current reactor fleet can become more economically competitive?

Mr. BOOK. I would actually turn to my colleagues on the panel who might know more about nuclear power than I.

Senator MANCHIN. Okay, who would like to take that?

Mr. Kavulla?

Mr. KAVULLA. I'll go first.

You are seeing greater operating cost reductions and capital productivity out of the merchant utility fleet that is coal and natural gas as opposed to nuclear. I'm not fully sure why that is—I assume nuclear's unique regulatory status under the NRC, the operating requirements that are imposed on it, the relatively limited size of the fleet and its lack of modularity, probably all had something to do with it.

But you're correct Senator that it's bigger, it's clunkier and if they're going to survive in a competitive market, they need to find those same kind of cost reductions that other people have in order to stay afloat in markets like——

Senator MANCHIN. Do you have any knowledge of the development of small modular reactors?

Mr. KAVULLA. Only that it's often been touted as the next generation technology, but none of them have been, so far, cleared into the market and there are a couple of those that are awaiting deployment.

But I'll put it this way, no one is sinking their own private risk capital——

Senator MANCHIN. Mr. Bill Gates is. He is putting billions in, and he is committed to put billions more. He is looking for a partner. I think the DOE is where he is looking for this partnership, and I want to know if any of you have knowledge of that or if you have been looking into that?

Mr. ZINDLER. A bit. And then I would echo what Travis is saying which is that the small modular reactors, SMRs, have been through the technologies of the future for, I think, 15, 20 years now. And we shall see.

I think it's important technology. I would just echo your original point though and add one, amplify one point, which is to note that, you know, nuclear represents this huge portion of zero carbon energy when it's produced.

Senator MANCHIN. Right.

Mr. ZINDLER. And if we're serious about climate change, we have to have a very rational policy about existing nuclear plants and what we can do to keep them online.

Senator MANCHIN. Well, Mr. Gates, I think,——

Mr. ZINDLER. Thank you, I'll take that.

Senator MANCHIN. I know.

[Laughter.]

No, I said we had a meeting with Mr. Gates concerning his development of reactors using spent fuel. So disposal would not be a problem and it would be universal internationally.

Do you know any of the challenges for advancement of these projects?

Mr. ZINDLER. Yeah, I would agree with Travis' point which is that such a venture requires a lot of private capital and it would be good if someone brings that to that conversation.

Senator MANCHIN. And then the last thing was basically on the grid system.

I have been hearing for years and years and years that we have a tremendous amount of shrinkage or waste as we deliver our power on the grid system. Have there been any upgrades you have seen?

I mean, I always thought that ceramics would be much more efficient transporting our power than what we're using, the old conventional methods. And there's been no changes for years.

Mr. BOOK. Well, I mean, technology shifts to a wholesale new technology tend to be expensive, particularly for the early adoption of those shifts and socialized rate bases don't generally welcome newly expensive increases.

So there have been——

Senator MANCHIN. That is a low hanging fruit, same as energy efficiency, basically. You are not wasting the fuel.

Mr. BOOK. There's been a lot of distribution build out that's helped to rationalize the grid and improve its efficiency, but moving it to next generation materials which, I mean, I don't know if you have comments but there's definitely price impacts that can be dissuasive.

Senator MANCHIN. Thank you very much.

Mr. KAVULLA. I'll also make the point, if I may, that regulatory model is different. You don't necessarily get rewarded for efficiencies in deploying that type of capital like you would be rewarded for efficiencies if you're operating a power plant in a competitive restructured market. And so, there's certain regulatory elements that impact here.

Senator MANCHIN. Sure.

Mr. KAVULLA. But I'll look at your witness list for Thursday and make sure someone is prepared to answer that question.

[Laughter.]

Senator MANCHIN. Thank you.

The CHAIRMAN. We better make sure that that one is addressed.

Senator Heinrich.

Senator HEINRICH. I am just glad we are talking about bunker fuel and small modular reactors and things that need some of this attention. When it comes to bunker fuel, you almost never hear about that in the energy conversation. Some of the stuff that gets burned in the hulls of ships around the world, if it were being burned in your hometown, you would be absolutely out on the streets with signs up because of the quality or lack of quality of some of that fuel. So I am glad you are bringing some attention to these issues.

I do want to go back to the physics issues for a minute, and I am sorry that Senator Cassidy is not here. I have had a little bit of experience with solar. I started with some students. We built a carbon fiber solar car that we raced from Dallas to Minneapolis in 1992 and 1993. I think we were doing very well if our efficiency of those actual cells were in the double digits, right? I mean, they were like the low double digits. And now I have a company in Albuquerque that is up in the 30 plus range for efficiencies.

But when you look at what has really driven penetration, it hasn't been changes in efficiency, and certainly the limits of the physics are real, but it has been all the other things that some people call Swanson's Law which says every time we double our manufacturing capacity we see a 20 percent drop in the cost of these systems.

Some of that comes from how we pay for those systems and financial models, and some of it comes from manufacturing improvements. Some of it comes from improved soft costs of just being able to work with your local utility and your local municipality to actually get this stuff installed on your roof. And that, I would suggest, is probably a bigger impediment than the physics in many of these arenas, which is why policy matters.

Mr. Kavulla, I want to ask you a question with respect to policy that I am very curious about. In your written testimony, you suggest the possibility of FERC acting as a backstop for siting of new interstate transmission power lines.

This is something I have wrestled with for a long time, and I do think you are correct in that the incentives for the nation as a whole and the incentives for individual states, oftentimes, don't match up and that is limiting our ability to develop transmission, in particular, as well as other energy projects. One option might be to link eligible projects to those that have been developed as part of a regional transmission plan required under FERC's Order 1000. Is that something that you have thought about, and what are your opinions on that matter?

Mr. KAVULLA. It is, Senator, something that I've spent a lot of time thinking about and a lot of time that FERC has spent thinking about as well.

Unfortunately, the ambitions of Order 1000 to encourage greater regional integration and planning are largely unfulfilled. FERC, I understand, is thinking about looking at Order 1000 again. I think it's a worthy consideration for them to do.

I hope they'll sharp shoot it to particular concerns rather than trying to reopen the entire book on it, because the hours of life that many lawyers, myself, others spent trying to implement Order

1000 are hours that we're not going to get back. And I'm almost positive that the transaction cost spent on it overwhelms whatever benefits it may have delivered.

But you know, you can go back to WEX modeling from 10 years ago for the United States West and see again and again models, again, taking them for what they're worth, models which suggested it is overall better for consumers for remotely sourced renewables to be developed for the urban population centers, so the Western United States.

Senator HEINRICH. Right.

Mr. KAVULLA. But we've never been able to get our act together.

Senator HEINRICH. I am running out of time quickly so one last one for you, Dr. Capuano.

In the past, AEO has always included charts with projections of economy-wide total carbon emissions. Those charts seem to be missing from this document. Why were they? Why did you decide to drop those?

Dr. CAPUANO. Sorry, I'm not aware that there are charts missing. In fact, we've included a carbon intensity graph in our AEO. So, I'm not——

Senator HEINRICH. There used to be a total carbon projection graph that was included along with the base projection and that doesn't seem to be in this.

Dr. CAPUANO. Oh, okay, we substituted the intensity graph because we thought it was more informative for that graph.

Senator HEINRICH. Okay.

Well I think total carbon emissions matter, so I would love to see them both in there.

Dr. CAPUANO. Thank you.

The CHAIRMAN. Thank you, Senator Heinrich.

Senator Cortez Masto.

Senator CORTEZ MASTO. Thank you.

Let me follow up on one discussion on the solar piece because I think we, as a country—and I so appreciate this conversation—we have to figure out how we take advantage in this space, moving forward. We are competing, as we know, with other countries, China in particular, when it comes to this space. From my perspective, I am always looking at ways we, at the federal level, can incentivize, support and move forward. The technology is constantly changing, and I think there is technology out there that we are not even thinking about, but we want to make sure we make it flexible enough for that innovation.

I'm curious if any of you are familiar with the Crescent Dunes Solar Energy Facility that is outside of Tonopah? Senator King had brought it up once before.

Senator KING. Is that the one with the mirrors?

Senator CORTEZ MASTO. That is correct.

Are any of you familiar with that?

Mr. ZINDLER. Molten salt.

Senator CORTEZ MASTO. That is right.

And so, here we have been talking about batteries and battery storage, but this facility uses molten salt for thermal storage, and it is connected to our grid in the State of Nevada. It is a different technique. It is this idea of solar thermal versus what we have been talking about, which is the solar PVs.

It is a new technology. It has energy storage. And something that I know after visiting that site is that they are also trying to address the environmentally-friendly piece of it as well.

This is an example of why I say we should not be restricting any of this innovation. We should be figuring out, as a country, how we work together to make sure we are incentivizing and allowing that flexibility, but with the necessary guard rails that might be there for protection.

I am curious if anybody has any comments?

Mr. ZINDLER. Just real quick, as luck would have it, actually last week I was visiting a similar plant in Morocco where they've just completed in August what's called the Noor Plant which is similarly, you know, a bunch of mirrors focused up on a heliostat, boil some fluid then there's molten salt.

It's a spectacular looking project. It has the potential to provide power into the evening hours. It's still pretty costly and there's a lot of moving parts and there are risks associated with solar thermal technologies as a result of that and there have definitely been some challenges over the last 10 years with getting those projects financed and completed and operating successfully. But you're exactly right that it has that potential.

The one thing I would say is, and I mentioned this earlier, is photovoltaics plus large-scale lithium-ion batteries could potentially provide some of the similar types of services into the evening with less moving parts, a little less risk and potentially lower cost as well, though we'll have to see on the costs.

Senator CORTEZ MASTO. Thank you.

I am not saying one is better than the other. Believe me, lithium mining in the State of Nevada and the battery storage we are looking at, we support that as well. I am just saying, from the perspective of the federal level, we should be exploring all of it. We should be figuring out how we allow that innovation to occur and not really cede this country's priority and our ability to take the lead around the world in this space. That, to me, is one of the most important things that we should be looking at as well.

Thank you.

The CHAIRMAN. Thank you, Senator, I certainly agree with that. Senator King.

Senator KING. [Off-mic]

The CHAIRMAN. So just to follow on with the mineral dependency, Mr. Moores, I really appreciate your testimony, your focus on that. Mr. Zindler, how you have knitted that in with the focus on the renewables and our efforts to reduce emissions.

I recognize that part of our challenge is not just the fact that we are not accessing the resource here but nowhere within this supply chain are we really engaged. And somebody used the terminology, you know, we are absent here.

And what did you say, Mr. Moores, because I actually wrote it down. "Those that hold the supply chain will control the balance of power, but we're basically a U.S. bystander." It kind of reminds me of the view that I think some in this country and this Administration have of the Arctic. We are just, kind of, the U.S. is just, kind of, a bystander here. And we cannot afford to be a bystander when we are looking, really, at the future here.

So much of this goes back to investment, because if people are not interested in investing you can have great ideas, you can have great resources but you, we don't get anywhere.

So I guess this is a question to both you, Mr. Moores, and Mr. Zindler, whether it is investment in our mineral opportunities and the multiple stages within that supply chain or whether it is the investment in the new energy technologies.

Mr. Zindler, you mentioned that worldwide investment in these new energy technologies is around $332 billion. I am curious what the breakdown is of the global number in terms of what comes from the U.S. compared to other countries. Are we keeping up with the investment level like we see from China? Let's just talk about investments for a second here.

Mr. ZINDLER. So just on those numbers, about a third of investment typically in a given year in clean energy technology or new energy technologies is usually it's China.

The CHAIRMAN. Is coming, is going to China?

Mr. ZINDLER. Is investment into China and about $65 billion last year was the U.S. So there's a gap and there has been pretty consistently over the last three or four years in particular with China leading just on pure dollars deployed. To be clear, a lot of that money comes out of China and goes into China.

The CHAIRMAN. Right.

Mr. ZINDLER. So China development bank, state-owned enterprises, various domestic companies are plowing money into their own operations there.

The CHAIRMAN. How about investment on the mineral side, Mr. Moores?

Mr. MOORES. Yes, it's a balance of investment in the incentive to source raw materials in the U.S. Okay, right now the raw materials to batteries aren't available from the U.S. So then you have to build the resource base, because it is present.

But investment globally in battery raw materials is happening, it's just at present better opportunities of the tier one opportunities from a resource perspective are not in the U.S. and that's primarily some of it's down to geology, some of it's down to the fact it hasn't been much of a mining industry in the U.S. for a long, long time. And so, at present the U.S. is almost at the back of the queue for the battery supply chain.

A good example of how this can work is the Tesla Gigafactory. So that's a lithium-ion battery plant that Tesla built with Panasonic in Nevada, and that's a good example of investment. Tesla put up some money. Panasonic put up some money. There was state level incentives and that battery plant can't make enough lithium-ion batteries for the vehicles that it sells. And so, that's almost, should be a case study for the EV supply chain within the U.S., and you should be replicating that time and time again in different states and then also encouraging the supply chain from the battery up to the mine to actually build out and build every step and drag in knowledge from the chemicals industry, from the mining industry. And a key part of that is the discussion. A key part is hearings like this that need to continue. We're just at the start.

The problem is China and Japan and Korea, we spend a lot of time there at Benchmark and it's happening at an incredible pace the last two years and it would just continue. It will just get more intense.

The CHAIRMAN. It is just such a reminder to me. We have some pretty good source material in Alaska for rare earth elements, but our reality is that we are not processing anything in this country so if we were able to extract it, where do we send it? To China? Only to get it back here.

So we are looking at a pretty significant pilot in the sense of being able to do something very different, but it is pretty small. But again, it is just a reminder that it is more than just having the resource itself, it is the access, it is the investment that can allow it to happen. But it is also the process, it is the workers that are trained. It is, as you point out, the whole supply chain.

My last question. When I talk about the Arctic and the U.S. role which, in my view, is still absolutely lacking, but where we have seen stepped-up interest in the Arctic and pursuing opportunities is with our neighbor, Russia, who has more than doubled its LNG exports. And by mid of this year I am told, they are scheduled to produce 26 million tons of LNG per year. This is going to be 10 percent of worldwide LNG exports. Two-thirds of this oil and gas is in the EEZ in the Arctic there, up in the Yamal Region, primarily.

I guess this is to you, Mr. Book or Dr. Capuano, just speaking to the Russian investment in the Arctic that we are seeing, the impact sanctions are having or perhaps not having on that development, what it means for the world energy markets. We have hit a little bit on Venezuela and Iran, but obviously Russia is out there as well. So and then, more broad, what do you see as the global Arctic energy future?

Mr. BOOK. Well, Madam Chairman, to the first question, the Russian supply, you can be of two minds about it. And I think in the formation of our sanctions we were. On the one hand, we want to punish Russia for malfeasance in Ukraine. On the other hand, we don't want to leave global supply short. And so, there's a structure of the sanctions to, sort of, leave the existing production alone and go after the future, the frontier production, the Arctic deep water and shale resources and technologies that are an investment from the U.S. companies. And what it's shown is that the vastness of their resource was such that with the things that they already had they could continue moving. The Yamal projects were years in the making and proceeded the implementation of sanctions.

I think that when you look into the difficulty in sanctioning a country with such a vast resource base, such a willful disregard for our economic state craft and, to be fair, even such a large market that depends on that, there's a lot of challenges in trying to structure something more punitive without having a deleterious price effect for the world. There's more power in some of the sanctions that are directed against Iran because the third-party nexus is in our reach. The Treasury can get into banks that transact in U.S. dollars on behalf of Iranian counterparties, and that has helped to, sort of, augment the effectiveness.

In terms of the Arctic, I think it would be a mistake to overlook a fifth of the world's petroleum resource, at the vastness of the opportunity. A lot of the challenge, I think, is always in investment, finding the fastest return with the highest degree, the highest probability of success.

And so, a lot of the changes that you have pioneered and the steps that have been taken are opening up new options. And I think that we'll really start to see when investor interest shows that there's going to be dollars put into some of the new developments that have been opened up in the Arctic where things can go. The vastness of the resource is not to be questioned, and I think it would be a mistake to not look for more oil because we're going to need it.

The CHAIRMAN. Dr. Capuano, anything to add?

Dr. CAPUANO. We look forward to modeling it.

[Laughter.]

The CHAIRMAN. Senator Cortez Masto, any final comments?

I want to thank you all. Very informative, very helpful to start off our new year here on the Committee.

I think, Dr. Capuano, you have used the appropriate term. This is a transformational time for us in this country. There is so much going on. It is exciting. It is fluid and perhaps sometimes difficult to predict because so much is happening as rapidly as it is.

What we want to try to do here in the Congress, in the legislative body, is make sure that our policies are as up-to-date and current as what is happening with the technologies. And my assessment on that is we are way behind the innovators out there in terms of policies that keep pace with our modern-day realities.

Thank you for your guidance as we try to shape our policies going forward, and thank you for your expertise and the time that you have given the Committee this morning.

With that, we stand adjourned.

[Whereupon, at 11:48 a.m. the hearing was adjourned.]

APPENDIX MATERIAL SUBMITTED

U.S. SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
Questions for the Record Submitted to Doctor Linda Capuano
February 5, 2019 Hearing: *The Outlook for Energy and Minerals Markets in the 116th Congress*

QUESTION FROM CHAIRMAN LISA MURKOWSKI

Q EIA's Annual Energy Outlook predicts that continued low natural gas prices and the increasing competitiveness of renewable generation will lead to the retirement of a substantial portion of our traditional baseload capacity by 2050. Setting aside the policy and reliability considerations, if EIA's prediction pans out, what level of additions to our nation's electric transmission, distribution, and natural gas transportation infrastructure will be needed to support the replacement of these resources?

A EIA does not specifically model the projected capital expenditures for the bulk electric transmission system or the local electric distribution systems.

However, EIA does account for the aggregate cost to interconnect new and replacement generating capacity with the electric transmission system. EIA's Annual Energy Outlook (AEO) 2019 Reference case projects electric transmission system investment to support the retirement of existing generating capacity and the interconnection of new generating capacity through 2050 to be $74 billion (2018 dollars). Since announced and projected baseload retirements represent 17% of total generating capacity additions through 2050, approximately $13 billion of the total $74 billion in electric transmission interconnection costs through 2050 could be attributed to the retirements.

In recent years, significant natural gas transportation infrastructure was constructed in the U.S. to facilitate development of shale gas resources. The AEO2019 Reference case does not project a need for further significant interstate pipeline infrastructure to meet domestic demand because of current excess capacity, pipelines already under construction, and the flexibility of the current interstate system. The AEO2019 does project the need to build additional pipeline capacity out of the Northeast —approximately 4 billion cubic feet per day, a 17% increase from 2018 capacity. However, this infrastructure is primarily needed to meet growing export demand, e.g., from liquefied natural gas (LNG) export facilities. In terms of meeting domestic demand from the electric power sector, most of the pipeline development will be focused on lateral spurs to new electric generators and intrastate pipelines. In particular, intrastate pipelines will be built to move Permian Basin production across Texas and into the existing interstate transmission system and demand markets along the Gulf Coast.

QUESTIONS FROM SENATOR MAZIE K. HIRONO

Q1. According to the Fourth National Climate Assessment, changing climate patterns will affect both the quality and quantity of the freshwater supply in Hawaii. Anticipating the growing challenges of changing rainfall patterns as well as an overall decline in freshwater supply, many states have begun investigating the use of non-traditional water sources to subsidize potable water supplies. Hawaii, for example, has begun to reuse some of its non-traditional water sources on golf courses and power plant cooling. I understand that EIA has modeled the increasing trend and energy efficiencies produced by the non-traditional water use in oil and gas production. Has EIA collected data and modeled the trend and energy efficiency associated with the use of non-traditional water as a supplemental potable water source? What, if anything, has EIA done to help federal and state agencies and policy-makers understand lifecycle water use, conservation, and management of non-traditional freshwater sources?

A1. EIA collects operational data for power plants with thermoelectric generators including the amount of water withdrawn, consumed, and discharged from the plant. EIA also collects data on plant cooling system design parameters such as the type and source of the water used for cooling applications, including plants that use reclaimed or treated wastewater for cooling purposes. EIA meets annually with USGS representatives to discuss water-related data collection and reporting issues concerning thermoelectric generating plants.

EIA has not modeled the use of non-traditional water as a supplemental source for energy production. Water-related issues tend to be local and are often site-specific. As a result, analysis on specific topics related to supplemental water sources would require more extensive data than is currently gathered by federal and state agencies. EIA has participated in stakeholder and expert group discussions on the energy-water nexus, contributed methodological advice at a highly aggregate level and monitors the progress in data collection.

Q2. During your confirmation hearing before the Energy and Natural Resources Committee in December 2017, you stated that you would work to improve the accuracy of EIA's modeling of renewable energy after years of EIA's models underestimating the actual deployment of solar photovoltaic systems and other renewable energy sources. What has the EIA done since your confirmation to improve the accuracy of renewable energy modeling used in the Annual Energy Outlook (AEO)? To what extent do any improvements in EIA's modeling account for the change in estimated solar photovoltaic generation in 2050 from 409 billion kilowatt-hours in the 2018 AEO to 543 billion kilowatt-hours in the 2019 AEO?

A2. Each published Annual Energy Outlook (AEO) includes updates that reflect changes in model assumptions as policies and market rules are updated; and changes in model structure as our understanding of markets and modeling research improves.

EIA made a number of model enhancements that resulted in an increase in the long term projection of variable renewable energy (VRE), i.e. wind and solar in the AEO2019. The most significant model enhancement was the development and inclusion of the new RESTORE module within the National Energy Modeling System (NEMS). VRE and energy storage are time dependent (temporally constrained) resources. RESTORE increases the temporal resolution when evaluating the value of these technologies and improves the measure of energy curtailments that result from increasing VRE deployment. RESTORE also accounts for technologies, such as energy storage, that alter the dispatch of the electricity generated in response to these lower marginal cost resources. The model was also enhanced to include changes in operating reserves requirements that result from increasing VRE penetration and changes to the marginal value for the capacity credit of VREs.

There were also a number of policy changes included in AEO2019. For example, in June 2018, the Internal Revenue Service (IRS) issued a new Investment Tax Credit guidance that set the construction timeline for large-scale solar projects to four years. The change in construction timeline assumption from two to four years led to an increase in solar deployment in near-term projections, which carried forward as an increase in solar generation through AEO2019 projection to 2050. In addition, the extension of the Renewable Portfolio Standard targets in four states in 2018 resulted in an increase in the required shares of electricity generation from renewable sources through the projection period.

Finally, EIA continues modeling research related to VRE. For example, EIA leads a significant multi-model collaboration effort with three major modeling entities: Electric Power Research Institute, U.S. Environmental Protection Agency, and the National Renewable Energy Laboratory. These four modeling teams compare and identify areas of potential model enhancement to improve the representation of VREs within each of their long-term projections (i.e., EIA's RESTORE module). The group has published two summarizing reports that provide more detail about the model changes that impact EIA's wind and solar projections discussed above.

Q3. The 2019 AEO expects only an average 0.1% annual decrease in carbon emissions from the power sector through 2050. That is not fast enough to help reduce the impacts of climate change on the people of the United States. Even though President Trump announced his intention to withdraw the United States from the Paris Climate agreement, Hawaii and other states have announced their continued commitment to implementing the goals of the Paris Climate agreement. At the reduction rate estimated in the AEO reference, how many years would it take for the United States to cut carbon pollution from the power sector by 28 percent compared to 2005 levels, in line with the pledge the United State made as part of the Paris Climate Agreement?

A3. Based on 2005 power sector carbon dioxide emissions of 2,416 million metric tons (MMT) and a preliminary estimate of 1,741 MMT in 2018, the U.S. power sector will have achieved a 28% reduction in carbon emissions in 2018. By 2050, the AEO2019 Reference case projects that the carbon dioxide emissions from the power sector will be 1,587 MMT or a decline of 34% relative to 2005.

QUESTIONS FROM SENATOR JOHN HOEVEN

Q1. To truly utilize the increasing development of more of our domestic energy resources, we must also increase our investment in energy infrastructure. How do we measure the amount of necessary investment in energy infrastructure over the next, say, 20 years?

A1. In the electric power sector, EIA projects in the AEO2019 Reference case that an additional 400 gigawatt of new generating capacity, along with supporting transmission and fuel supply infrastructure, will be built by 2040 to meet growing demand for electricity and replace retiring generating capacity. EIA expects that nearly all of this additional capacity will rely on domestic supplies of natural gas, wind, and solar power.

In the oil and gas sector, EIA projects that domestic production of crude oil and natural gas liquids will increase approximately 33% between 2018 and 2040. This growth will require investment to support an additional 5 million barrels per day of liquids production and transportation. EIA expects domestic production of dry natural gas to increase by about 40%, or 11 trillion cubic feet per year and require additional production and transportation infrastructure.

EIA does not project a need for further significant interstate pipeline infrastructure to meet domestic demand because significant natural gas pipeline infrastructure has been constructed in the U.S. to facilitate development of shale gas resources. In addition, there is available excess capacity, there are pipelines currently under construction, and there is flexibility in the existing interstate system.

However, the AEO2019 does project the need to build additional pipeline capacity out of the Northeast —approximately 4 billion cubic feet per day, a 17% increase from 2018 capacity; to meet growing export demand, e.g., from LNG export facilities. Most of the pipeline development will be focused on lateral spurs to new electric generators and intrastate pipelines to connect supply basins or individual consumers (e.g. industrial facility, town or community) to the transmission network. In particular, intrastate pipelines will be built to move Permian Basin production across Texas to LNG export facilities on the Gulf Coast. There will also be investments in U.S. import and export facilities for petroleum liquids and natural gas.

Q2. Regulatory certainty encourages private sector investment. When there is uncertainty about the regulatory process, companies withhold major, long-term investments that can help modernize our energy infrastructure. How can Congress work to streamline federal agency review and approval processes to ensure projects are not delayed?

A2. EIA is, by charter, policy-neutral and does not develop nor advocate for policies that affect the energy industry. EIA has significant capability through its National Energy Modeling System (NEMS) to evaluate the impact of major legislative and regulatory policies developed by Congress. To the extent that the cost of regulatory uncertainty can be observed in energy and economic data, EIA can and does introduce that cost into its economic models. However, energy economic data is inherently noisy, and it is often difficult to separately estimate the cost of regulatory uncertainty from available project financing data.

In its Annual Energy Outlook 2018, EIA published the results from several cases that addressed the impacts of regulatory uncertainties on energy markets. In one set of cases, EIA examined the potential impacts of either permanently extending federal tax credits for renewable energy or immediately terminating these credits. A separate set of cases looked at tightening existing energy efficiency regulations for buildings and transportation markets or of eliminating future ratcheting of these regulations. Together, these cases provided bounding estimates of the uncertain decision to extend or eliminate these regulations, and show potentially significant impacts on both the level and timing of investments in renewable energy, energy consumption in residential and commercial buildings, and in the market for light duty vehicles.

U.S. Senate Committee on Energy and Natural Resources
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Question for the Record Submitted to Mr. Kevin Book

Question from Senator John Hoeven

Question: You mention in your testimony that our nation has experienced three major phases of net imports for oil and gas: surviving scarcity, adapting to adequacy, and expanding our exports. The U.S. is estimated to become a net exporter of petroleum in 2020; however, lawmakers must deliberate over regulatory policies that were written during different economic times. How can Congress work to eliminate ambiguities in existing oil and gas regulatory policy and ensure the U.S. market continues to grow?

Answer: Senator, thank you for the question. As the U.S. oil boom has progressed, several regulatory bottlenecks have delayed or deterred infrastructure intended to connect upstream resources to domestic and international markets.

One area of uncertainty concerns the scope of environmental reviews, particularly when assessing the greenhouse gas (GHG) emissions implications of planned projects. Specifically, the question of whether to judge the environmental impact of infrastructure on the basis of its own emissions (e.g., from compressor stations and from the fuels consumed during construction) or on the basis of the resources that traverse it (i.e., "upstream" at well sites and processing facilities and "downstream" in end-use applications such as transportation, power generation, etc.) continues to weigh on development.

Pipeline opponents contend that regulators should assess and incorporate the GHG emissions impacts upstream and downstream of planned infrastructure. Project sponsors hold that assessments of upstream and downstream impacts should occur in the context of existing regulatory proceedings that govern upstream production or downstream end-use activities. Regulators, including the Federal Energy Regulatory Commission (FERC), have suggested that it can be difficult, if not impossible, to allocate specific upstream resources to a given midstream project. Such assessments can delay reviews (because they tend to be labor-intensive) and create litigation risk (because of the foregoing allocation difficulties).

To use a simplifying metaphor: is a door just a door? Or should the door be held to account for everything that passes through it? This is no small question. Regulatory clarity on this issue could reduce permitting latency under the *National Environmental Policy Act* (NEPA) and potentially obviate legal challenges during and after the permitting process.

A second area of uncertainty concerns water-related permitting authorities for energy transportation infrastructure. Pipelines that cross water bodies and wetlands generally require, variously, a U.S. Army Corps of Engineers permit issued pursuant to Nationwide Permit 12 ("NWP 12") or an individual state-issued water quality certification (and, in some cases, both). The former is a periodic, national program intended to address minor waterbody crossings. The latter is a federal permit issued by the states under delegated authority from the EPA pursuant to Section 401 of the *Clean Water Act* ("CWA §401"). The type of approval required depends on a given state's approach and the water bodies involved. Some states administer all water body (and wetlands) crossings through CWA §401 review. Others states rely on the NWP 12 program, unless a project doesn't meet a state-specific characteristics or set of characteristics (for example, projects of a certain size).

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The CWA §401 program has come to represent both a front in green groups' assaults on individual pipeline projects and, increasingly, a potential point of state-federal jurisdictional tension to the extent that some states have sought to wield it as a "veto" over pipeline infrastructure (or have been encouraged to do so). The initial battles have played out in state regulatory bodies and the nation's federal courts. Although the Trump Administration has indicated that it plans to streamline permitting, states that do not wish to cede existing jurisdiction over energy infrastructure seem likely to resist. As a result, both sides seem likely to continue tasking courts with resolution of CWA §401 conflicts.

A third area of uncertainty concerns the Presidential permitting process for cross-border energy infrastructure. I know this is an issue with you are well familiar, Senator Hoeven, and I will not dwell on it here in my response. Suffice to say, however, that the many junction points that afford legal challenges to pipeline projects being permitted under authority delegated to the State Department have contributed not only to project uncertainty, but also to genuine want of heavy oil volumes from Canada since the January 28 implementation of sanctions against the Maduro regime. If the Keystone XL pipeline had been permitted and constructed years ago, Gulf Coast refiners might have been able to diversify away from Venezuelan supply much sooner and less abruptly. In short, pipeline flows across our northern border from an adjacent, reliable partner can enable energy security at home and facilitate economic force projection against American rivals overseas.

In sum, all three areas of uncertainty present hurdles to investment, economic growth and energy security. All three can be addressed by American jurisprudence and modified by Executive Branch authority, but legislative reforms may offer the most durable mechanism for eliminating these uncertainties.

U.S. Senate Committee on Energy and Natural Resources
February 5, 2019 Hearing: *The Outlook for Energy and Minerals Markets in the 116th Congress*
Questions for the Record Submitted to Mr. Travis Kavulla

Questions from Chairman Lisa Murkowski

Questions: You describe the substantial changes to our power generation fuel mix that have occurred over the past decade. While natural gas and renewables have boomed, traditional baseload resources have declined. What are your thoughts on the grid reliability challenges posed by this rapidly changing fuel mix? Are we moving toward this new energy mix at too fast a pace?

Answer:
Grid reliability is a topic of paramount concern, and there are important reforms that could better ensure system reliability and do so in a way that protects consumers.

The first reform, as I mention in my written testimony, is to encourage the transformation of regulatory mandates for "forward capacity" into markets that reward resources for their contributions to system reliability at the times when they are actually needed. Texas is a good, if not perfect, example of such a marketplace. There, a dynamic demand for operating reserves is based on the probability of the intermittency of certain power resources and the variation of customer demand. The greater tendency of the latter, the more demand there is for the former, which can keep the lights on when unexpected events occur. This is a far better way to buy what the grid actually requires of the power-generation sector in order to remain reliable. The way forward in the ongoing debate surrounding forward capacity constructs should be to urge their replacement by these operational capacity markets.

Second, although such markets should facilitate a trade in those services that are needed to keep the grid reliable, it may be the case that certain essential reliability services are sufficiently discrete that they should be separately identified and procured. For example, NERC has flagged inertia as one of the essential reliability services about which it is concerned, and I partially agree with the reliability agency that, "It is important to start planning for the projected future resource mix rather than wait for synchronous inertia to reach the minimum value."[1] To the degree that I disagree with NERC's statement, it is only because of the implication of the word "planning"—which suggests that system managers should ordain the mix of resources that would supply inertia. Instead, the more appropriate, cost-effective, and innovative approach would be to specify the technical requirements associated with inertia, and then procure it through a reverse auction where certified suppliers of inertia are the bidders.

Finally, it is crucially important that the wholesale prices of power actually reflect the system's real-time conditions. As I emphasized in my oral statement to the Committee, it is perplexing that even when grid operators have deployed what the Energy Information Administration calls "emergency operating procedures," wholesale prices have remained unusually low.[2]

Put another way, these three recommendations constitute one major principle: If there is no source of revenue for innovators, developers and utilities who could and would provide reliability services, then the system will either be unreliable, or will be reliable not by design but by accident.

[1] NERC, *Essential Reliability Services: Whitepaper on Sufficiency Guidelines* (December 2016), p. v. Available at: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf.
[2] "Extreme cold in the Midwest led to high power demand and record natural gas demand," EIA, Feb. 26, 2019, available online at: https://www.eia.gov/todayinenergy/detail.php?id=38472

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Recent cold weather in parts of the country has suggested that there are still more than enough power-generating resources, and enough diversity of fuel mix, to keep the system reliable from a power-generation perspective.[3] But the time to implement reforms that drive toward a continuously reliable system is now, and not when problems emerge.

Once again, I thank you for the opportunity to testify before your Committee. Your commitment to address issues of technical concern to this sector is a welcome one, and I appreciate the opportunity to add to the record with my answer herein.

[3] *Id.* Indeed, EIA's analysis of the past three severe-weather events affecting MISO suggest that this grid has an increasingly diverse mix of fuels that are supporting reliable operations.

BENCHMARK MINERAL INTELLIGENCE

18 February 2019

Simon Moores, Managing Director, Benchmark Mineral Intelligence
Response to Question for the Record

U.S. Senate Committee on Energy and Natural Resources
February 5, 2019 Hearing: *The Outlook for Energy and Minerals Markets in the 116th Congress*
Question for the Record Submitted to Mr. Simon Moores

Question from Senator James E. Risch

Question: I commend the designation of cobalt as a critical mineral. My state of Idaho has become a focal point for enhancing our domestic supply of cobalt. Currently most of the world's supply comes from Congo, much of it from small-scale mining with problematic health and environmental practices. Furthermore, much of the processing of cobalt is done by Chinese firms.

As the global requirement for advanced energy storage systems increase, in your opinion, where are we going to find new sources of cobalt and what should the U.S. government do to ensure a robust and reliable domestic cobalt supply?

Response from Simon Moores:

The Idaho belt is the US' primary potential source of domestic cobalt.

First Cobalt, eCobalt Solutions, and Battery Mineral Resources, among others, have been developing resources in Idaho, yet permitting and funding has stifled the progress.

It can take the best part of a decade to build a mine from resource discovery to first production, yet it only takes 24 months to build an electric vehicle battery plant. Funding for these mining operations usually happens in a 3-year window when cobalt prices rise due to supply restrictions or increased demand and a global investment rush ensues.

However, this rush of investment tends to flow into existing operations outside of the US or other financial instruments related to cobalt. It does not flow in to building new mined supply, especially in the US.

It is quite clear that in the next 3-5 years we will have another cobalt supply crisis thanks to the rising demand from electric vehicles and energy storage coupled with a significant lack of investment in new supply.

In 2018, according to Benchmark Mineral Intelligence data, 70% of the world's mined cobalt (96,000 tonnes) was mined in the Democratic Republic of Congo (DRC) of which 75% (72,000 tonnes) was destined for China.

As you correctly point out, much of the world's cobalt refining occurs in China. In 2018, China refined 62% of the worlds cobalt products which in itself is a significant figure. But in the case of cobalt chemicals (the form that is used in lithium ion batteries) over 80% were refined in China.

Furthermore, at Benchmark Mineral Intelligence, we expect this 80% figure to grow as we have seen a cobalt refining capacity build out in China over the past 18 months.

The US has zero cobalt mines, zero cobalt refining capacity and zero cobalt chemical capacity.

The US has traditionally kept stockpiles of cobalt but these have been sold down.

In China it is a different story: the country's grip on the cobalt to EV battery supply chain is fierce and increasing.

The only major US asset is Freeport Cobalt (Part of Arizona's Freeport-McMoRan Inc) which owns and operates a refinery in Finland after it sold its 54% stake in the DRC-based Tenke Fungurume cobalt mine to China Molybdenum for $2.65bn in 2016 to pay down debt.

It is important to add that whilst much of the worlds cobalt supply comes from the DRC, 40% of 2018 production was under Chinese ownership, with zero percent owned by US based companies.

Continued

Benchmark Minerals' Recommendations:

The US has to seriously consider new ways to help domestic development of the cobalt, lithium, nickel and graphite supply chain – from the mine to the battery grade chemical stage – if it is to reduce the risk of not being able to make lithium ion batteries for its auto and energy industries.

These recommendations are not just for cobalt but the entire suite of EV and energy storage minerals that can be classified, from Benchmark Minerals' perspective, as **Minerals of Severe Economic Risk** – a step beyond their Critical Minerals classification.

Without the supply chains in place for these raw materials, the 21st Century Auto and Energy Industries will be stifled or starved of the key raw materials that make the lithium ion batteries that are central to their businesses.

These following recommendations are also applicable to every state in the US and is not just Idaho-specific.

1. **Permitting**:
   A. **Streamlining**: Faster permitting approval process, including clearly laid out dates and deadlines for permit applications and reviews; Setting timelines that are realistic, not arbitrary, is critical.

      In other developed and developing nations, permit applications requiring reviewal and approval or rejection are processed in a set time period – usually 90 to 180-day limits; In the US, the review process can take up to multiple years for the same activity that is completed in 90 days overseas.

      This is not to say the review is any less comprehensive, in fact many of the foreign systems, like the Government of Chile, impose the strongest environmental reviews and regulations (a combination of the IMF rules and those of California)

   B. **EA to EIA:** Shifting initial project reviews from an Environmental Assessment (EA) instead of an Environmental Impact Statement (EIS) could potentially save 1-3 years in the permitting process

   C. **Onboarding Officer**: Establish an Onboarding Officer as a focal point for these projects under the **Minerals of Severe Economic Risk** list and at the level of the US agencies rather than, in some cases, just at the state level.

      This will aid with communication, questions and problems that arise during permitting and can speed up the process.

   D. **Combined permits**: Formal Inter-agency communication for these minerals so that water, land, air, reclamation and other required permits are all under one application; some states will have this in place informally and it is especially needed between the Bureau of Land Management (Interior) and the Forest Service (Agriculture) and the US Army Corp of Engineers (Water)

2. **Regulation**:

    A. **Project Access**: The permanent closing of Forest Service roads has hindered some projects access to remote areas

    B. **Data Access**: Access to GIS data with respect to proposed land reclassifications, wildlife management/conservation, and any other land designations would help new resource discoveries and existing developments

    C. **Process Efficiency**: Up-to-date data and less lag time between county Clerk and Recorder filing of claims and recording mineral claims in the LR2000 database; this process can take several months

    D. **Exploration Fees**: A freeze or suspension of filing and annual maintenance fees around critical mineral exploration – this will act as financial incentive to promote exploration

3. **Financing**:

    A. **Higher Priority**: A government mechanism to help prioritise new operations and obtain project finance on a debt basis for the high-risk phases of construction and early operations as it ramps up to full capacity

    B. **Tax Incentives**: Financial incentive for new equity investment via an EV Supply Chain Investment Tax Credit or a Tax Honeymoon– an evolution of the Investment Tax Credit with aided several renewable energy projects.

    C. **Investment Tax Credit**: Introduce an investment tax credit similar to the flow through shares (FTS) incentive in Canada – these are newly issued shares that have the same attributes generally attached to common shares

All of these new steps should work towards the common goal of EV and energy storage supply chain integration.

New mines which choose to add the chemical processing or refining steps towards a lithium ion battery, which includes cathodes and anodes, should be prioritised for approval, particularly if this processing step is under a joint venture with partnership within the US or with US-based companies.

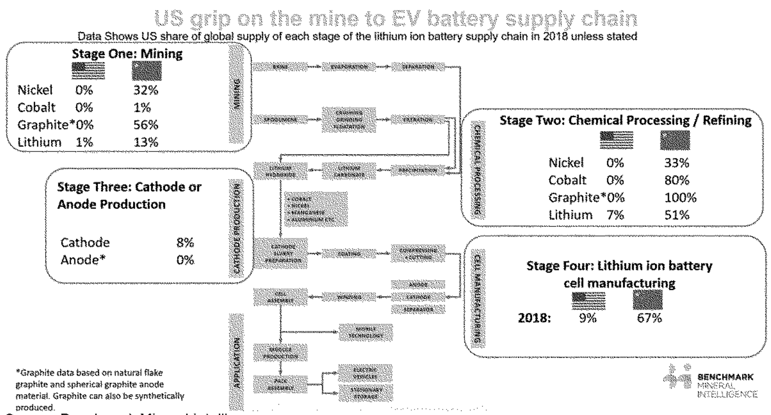
It is critical that US mined raw materials make it into US made lithium ion batteries and electric vehicles to not only capture the value but secure these supply chains for the 21st Century.

You cannot make a lithium ion battery without cobalt and right now the US faces a high risk of another situation similar to rare earths in 2010.

Yet unlike rare earths, cobalt demand is set to significantly increase by five-fold in the next decade, reshaping the way the industry does business. In many ways, it is a more critical situation.

The Benchmark Mineral Intelligence team are also at the disposal of the Senate to discuss this subject in further detail.

The below chart outlines how precarious the US cobalt position is today:



Source: Benchmark Mineral Intelligence

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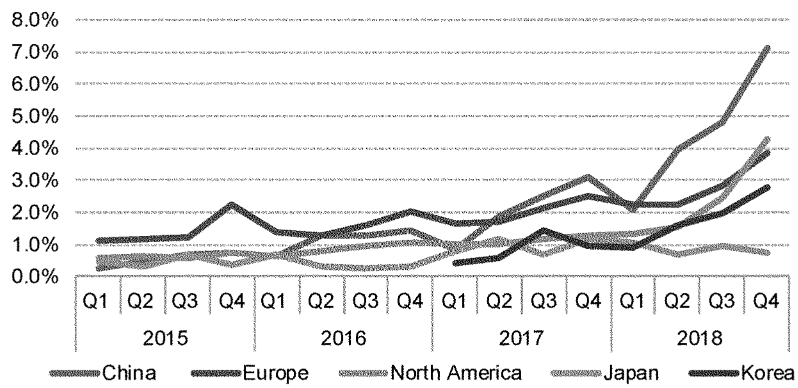
U.S. Senate Committee on Energy and Natural Resources
February 5, 2019 Hearing: *The Outlook for Energy and Minerals Markets in the 116th Congress*
Question for the Record Submitted to Mr. Ethan Zindler

Question from Senator Mazie K. Hirono

Question: In response to questions during the hearing, you observed that the United State does not generate the same demand for investment in electric vehicle and battery technology development as China. What policies have other countries applied that you would recommend Congress consider to ensure that the jobs and technology advances associated with electric vehicles are enjoyed by people in the United States?

First, to clarify and underline my point, the chart below shows the very latest figures of electric vehicle (EV) sales through the end of 2018.

EV sales as a percentage of total vehicle sales, by region/country



A variety of policies have been implemented in jurisdictions around the globe to support EV adoption. Generally, these have involved subsidies that have flowed directly to consumers. In some cases, however, jurisdictions have simply made it more difficult for consumers to obtain a car of any kind, unless it is an EV. This has been the case in some parts of China and accounts in part for the rapid rate of EV adoption there.

In terms of direct to consumer subsidies, the U.S. of course offers tax credits to consumers who buy EV's. This is currently pegged at $7,500/vehicle but phases down as automakers pass certain milestones for EV sales. Certain automakers have begun to hit their quotas, including most notably to date, Tesla.

An even more generous subsidy is available in Norway, which originally exempted consumers entirely from paying its Value Added Tax (VAT) and purchase tax if they bought an EV. Between them, these

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Question for the Record Submitted to Mr. Ethan Zindler

taxes typically account for about one half the final price of a vehicle, so this represented a massive discount for consumers. Today, Norway has the highest level of electric vehicle market penetration of any individual country, as a result. This subsidy is quite costly, however, and may not be wise (or affordable) for other nations to emulate.

EV deployment can be supported further up the value chain as well. Batteries today account for the majority of the cost of a typical EV. We at BNEF anticipate demand for EV's to grow exponentially over the next 20 years, with such cars accounting for one half of light-duty vehicle sales and one third of light-duty vehicles on the road, by 2040. This will put unprecedented pressure on the battery supply chain. EV's (inclusive of electric buses) have already overtaken consumer electrics as the largest source of lithium-ion battery demand. In 2017, total demand for such batteries was 44 gigawatt hours per year. That will grow by a factor of 34 to 1,500GWh/year by 2030.

This new demand will represent a massive economic opportunity for regions or countries that produce the materials used in such batteries or the batteries themselves. Already, we have seen certain states and localities offer tax exemptions to entice firms to build manufacturing facilities locally. Most notably, the state of Nevada offered tax breaks and other incentives totaling $1.3 billion to convince Tesla to build its "Gigafactory" in state, according to news reports.

At the federal level, the U.S. government did offer very generous tax subsidies under the American Recovery and Reinvestment Act of 2009 to support the development of advanced manufacturing plants under section 48C of the law. It offered a tax credit that essentially provided a 30% discount off the total cost of any qualifying new facility. The program was not as successful as it might have been as it was made available to firms at the height of the recession when many firms lacked funds of their own to build manufacturing plants even with such a generous subsidy. That is not necessarily an indictment of the policy, so much as a comment on the timing of when it was made available.

Annual Energy Outlook 2019

with projections to 2050

Independent Statistics & Analysis
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The Annual Energy Outlook provides long-term energy projections for the United States

- Projections in the *Annual Energy Outlook 2019* (AEO2019) are not predictions of what will happen, but rather modeled projections of what may happen given certain assumptions and methodologies.
- The AEO is developed using the National Energy Modeling System (NEMS), an integrated model that captures interactions of economic changes and energy supply, demand, and prices.
- Energy market projections are subject to much uncertainty because many of the events that shape energy markets as well as future developments in technologies, demographics, and resources cannot be foreseen with certainty. To illustrate the importance of key assumptions, AEO2019 includes a Reference case and six side cases that systematically vary important underlying assumptions.
- More information about the assumptions used in developing these projections will be available shortly after the release of the AEO2019.
- The AEO is published to satisfy the Department of Energy Organization Act of 1977, which requires the Administrator of the U.S. Energy Information Administration to prepare annual reports on trends and projections for energy use and supply.

What is the Reference case?

- The AEO2019 Reference case represents EIA's best assessment of how U.S. and world energy markets will operate through 2050, based on many key assumptions. For instance, the Reference case projection assumes improvement in known energy production, delivery, and consumption technology trends.
- The economic and demographic trends reflected in the Reference case reflect current views of leading economic forecasters and demographers.
- The Reference case generally assumes that current laws and regulations that affect the energy sector, including laws that have end dates, are unchanged throughout the projection period. This assumption is important because it permits EIA to use the Reference case as a benchmark to compare policy-based modeling.
- The potential impacts of proposed legislation, regulations, or standards are not included in the AEO2019 cases.
- The Reference case should be interpreted as a reasonable baseline case that can be compared with the cases that include alternative assumptions.

What are the side cases?

- The side cases in AEO2019 show the effect that changing important model assumptions have on the projections when compared with the Reference case.
- Two AEO2019 side cases are the High and Low Oil Price cases, which represent international conditions outside the United States that could collectively drive prices to extreme, sustained deviations from the Reference case price path.
- Additional AEO2019 side cases are the High and Low Oil and Gas Resource and Technology cases, where production costs and resource availability within the United States are varied, allowing for more or less production at given world oil and natural gas prices.
- The two AEO2019 side cases that vary the effects of economic assumptions on energy consumption are the High and Low Economic Growth cases, which modify population growth and productivity assumptions throughout the projection period to yield higher or lower compound annual growth rates for U.S. gross domestic product than in the Reference case.

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Key takeaways

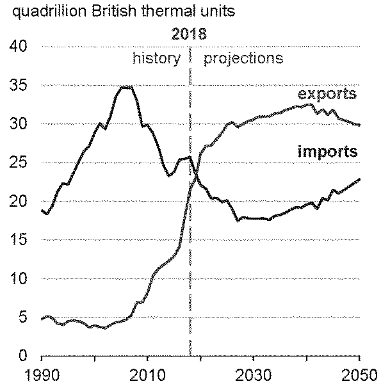
EIA's *Annual Energy Outlook* provides modeled projections of domestic energy markets through 2050, and it includes cases with different assumptions regarding macroeconomic growth, world oil prices, and technological progress.

Key takeaways from the Reference case

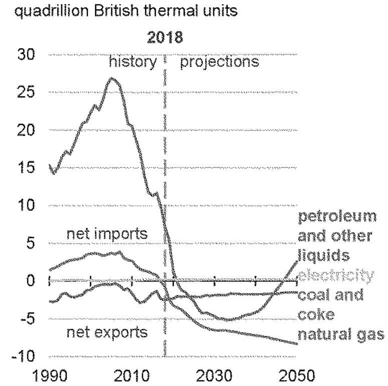
- The United States becomes a net energy exporter in 2020 and remains so throughout the projection period as a result of large increases in crude oil, natural gas, and natural gas plant liquids (NGPL) production coupled with slow growth in U.S. energy consumption.
- Of the fossil fuels, natural gas and NGPLs have the highest production growth, and NGPLs account for almost one-third of cumulative U.S. liquids production during the projection period.
- Natural gas prices remain comparatively low during the projection period compared with historical prices, leading to increased use of this fuel across end-use sectors and increased liquefied natural gas exports.
- The power sector experiences a notable shift in fuels used to generate electricity, driven in part by historically low natural gas prices. Increased natural gas-fired electricity generation; larger shares of intermittent renewables; and additional retirements of less economic existing coal and nuclear plants occur during the projection period.
- Increasing energy efficiency across end-use sectors keeps U.S. energy consumption relatively flat, even as the U.S. economy continues to expand.

The United States becomes a net energy exporter after 2020 in the Reference case—

Gross energy trade (Reference case)
quadrillion British thermal units



Net energy imports (Reference case)
quadrillion British thermal units



—but the United States continues to import and export throughout the projection period

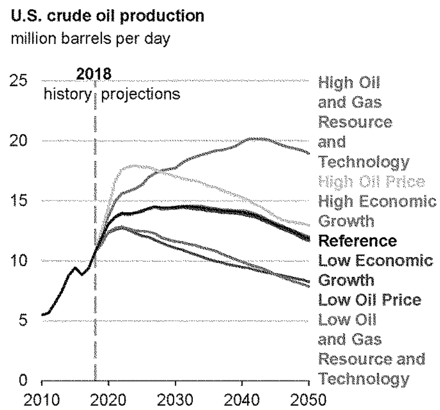
- The United States has been a net energy importer since 1953, but continued growth in petroleum and natural gas exports results in the United States becoming a net energy exporter by 2020 in all cases.

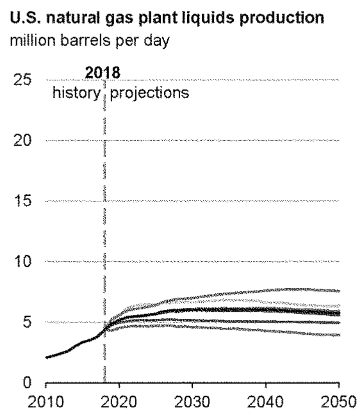
- In the Reference case, the United States becomes a net exporter of petroleum liquids after 2020 as U.S. crude oil production increases and domestic consumption of petroleum products decreases. Near the end of the projection period, the United States returns to being a net importer of petroleum and other liquids on an energy basis as a result of increasing domestic gasoline consumption and falling domestic crude oil production in those years.

- The United States became a net natural gas exporter on an annual basis in 2017 and continued to export more natural gas than it imported in 2018. In the Reference case, U.S. natural gas trade, which includes shipments by pipeline from and to Canada and to Mexico as well as exports of liquefied natural gas (LNG), will be increasingly dominated by LNG exports to more distant destinations.

- The United States continues to be a net exporter of coal (including coal coke) through 2050 in the Reference case, but coal exports are not expected to increase because of competition from other global suppliers closer to major world markets.

Production of U.S. crude oil and natural gas plant liquids continues to grow through 2025 in the Reference case—





—and natural gas plant liquids comprise nearly one-third of cumulative 2019–2050 U.S. liquids production

- In the Reference case, U.S. crude oil production continues to set annual records through 2027 and remains greater than 14.0 million barrels per day (b/d) through 2040. Lower 48 onshore tight oil development continues to be the main source of growth in total U.S. crude oil production.

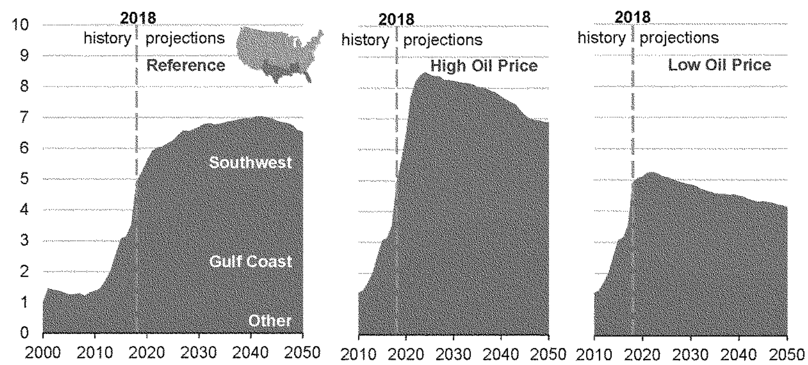
- The continued development of tight oil and shale gas resources supports growth in natural gas plant liquids (NGPL) production, which reaches 6.0 million b/d by 2029 in the Reference case.

- The High Oil and Gas Resource and Technology case represents a potential upper bound for crude oil and NGPL production, as additional resources and higher levels of technological advancement result in continued growth in crude oil and NGPL production. In the High Oil Price case, high crude oil prices lead to more drilling in the near term, but cost increases and fewer easily accessible resources decrease production of crude oil and NGPL.

- Conversely, under conditions with fewer resources, lower levels of technological advancement, and lower crude oil prices, the Low Oil and Gas Resource and Technology case and the Low Oil Price case represent potential lower bounds for domestic crude oil and NGPL production. Changes in economic growth have little impact on domestic crude oil and NGPL production.

The United States continues to produce large volumes of natural gas from oil formations, even with relatively low oil prices—

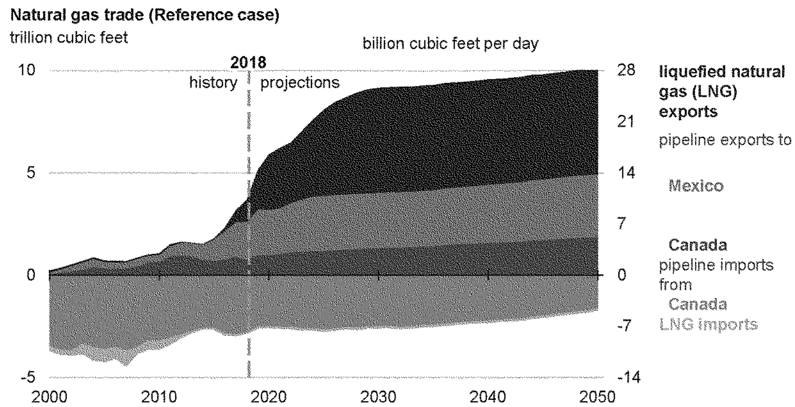
Dry natural gas production from oil formations
trillion cubic feet



—putting downward pressure on natural gas prices

- The percentage of dry natural gas production from oil formations increased from 8% in 2013 to 17% in 2018 and remains near this percentage through 2050 in the Reference case.
- Growth in drilling in the Southwest region, particularly in the Wolfcamp formation in the Permian basin, is the main driver for natural gas production growth from tight oil formations.
- The Low Oil Price case, with the U.S. crude oil benchmark West Texas Intermediate (WTI, Cushing, Oklahoma) price at $58 per barrel or lower, is the only case in which natural gas production from oil formations is lower in 2050 than at current levels.
- The level of drilling in oil formations primarily depends on crude oil prices rather than natural gas prices. Increased natural gas production from oil-directed drilling puts downward pressure on natural gas prices throughout the projection period.

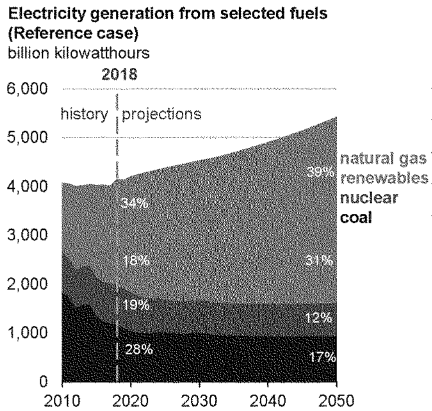
U.S. net exports of natural gas continue to grow in the Reference case—

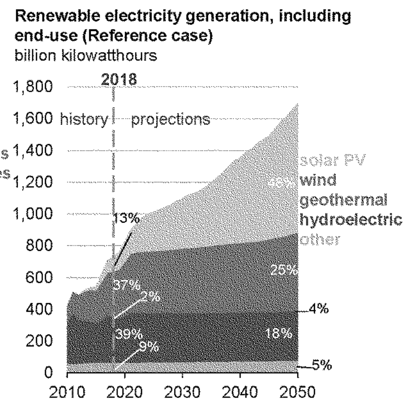


—as liquefied natural gas becomes an increasingly significant export

- In the Reference case, U.S. liquefied natural gas (LNG) exports and pipeline exports to Canada and to Mexico increase until 2030 and then flatten through 2050 as relatively low, stable natural gas prices make U.S. natural gas competitive in North American and global markets.
- After LNG export facilities currently under construction are completed by 2022, U.S. LNG export capacity increases further. Asian demand growth allows U.S. natural gas to remain competitive there. After 2030, U.S. LNG is no longer as competitive because additional suppliers enter the global LNG market, reducing LNG prices and making additional U.S. LNG export capacity uneconomic.
- Increasing natural gas exports to Mexico are a result of more pipeline infrastructure to and within Mexico, resulting in increased natural gas-fired power generation. By 2030, Mexican domestic natural gas production begins to displace U.S. exports.
- As Canadian natural gas faces competition from relatively low-cost U.S. natural gas, U.S. imports of natural gas from Western Canada continue to decline from historical levels. U.S. exports of natural gas to Eastern Canada continue to increase because of its proximity to U.S. natural gas resources in the Marcellus and Utica plays and because of recent additions to pipeline infrastructure.

Electricity generation from natural gas and renewables increases, and the shares of nuclear and coal generation decrease—





—as lower natural gas prices and declining costs of renewable capacity make these fuels increasingly competitive

- The continuing decline in natural gas prices and increasing penetration of renewable electricity generation have resulted in lower wholesale electricity prices, changes in utilization rates, and operating losses for a large number of baseload coal and nuclear generators.

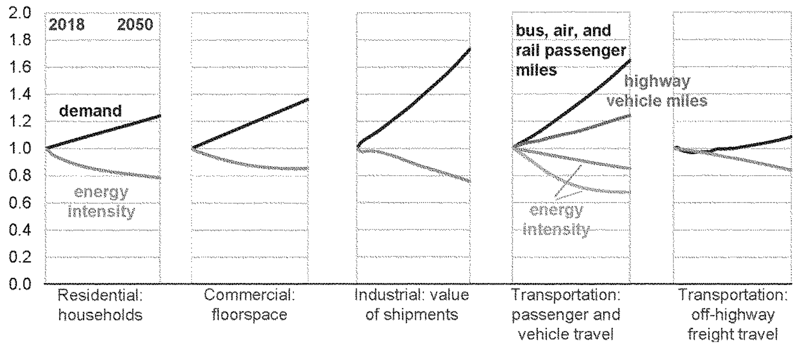
- Generation from both coal and nuclear is expected to decline in all cases. In the Reference case, from a 28% share in 2018, coal generation drops to 17% of total generation by 2050. Nuclear generation declines from a 19% share of total generation in 2018 to 12% by 2050. The share of natural gas generation rises from 34% in 2018 to 39% in 2050, and the share of renewable generation increases from 18% to 31%.

- Assumptions of declining costs and improving performance make wind and solar increasingly competitive compared with other renewable resources in the Reference case. Most of the wind generation increase occurs in the near term, when new projects enter service ahead of the expiration of key federal production tax credits.

- Solar Investment Tax Credits (ITC) phase down after 2024, but solar generation growth continues because the costs for solar continue to fall faster than for other sources.

End-use activities grow, and energy intensities decrease in all sectors in the Reference case—

Indexed end-use demand drivers and energy intensities by sector (2018–50) (Reference case)
index (2018=1.0)



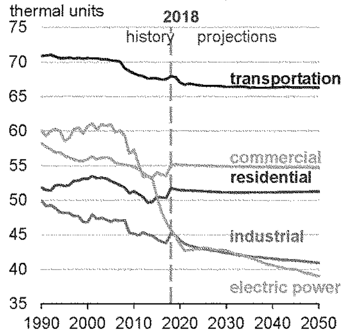
Note: Energy intensities are a lighter shade of the same color as the respective demand, and they are calculated as energy used per unit of respective demand.

—offsetting each other to limit energy consumption growth

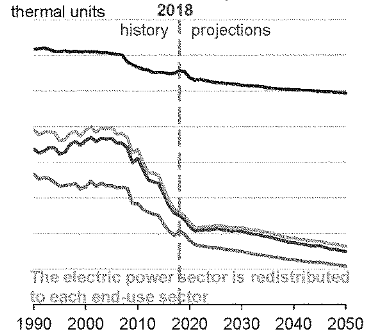
- Delivered U.S. energy consumption grows across all major end-use sectors, with electricity and natural gas growing fastest. However, increases in efficiency, represented by declines in energy intensity (the amount of energy consumed per unit of potential demand), partially offset growth in total U.S. energy consumption across all end-use sectors.
- The end-use sectors have different representative metrics for demand used to estimate energy intensity—number of households for the residential sector, floorspace for the commercial sector, industrial value of shipments for the industrial sector, and travel metrics for the transportation sector.
- Transportation travel is measured in three ways, depending on the mode: highway vehicle miles (light- and heavy-duty vehicles), passenger miles (bus, passenger rail, and air), and off-highway freight ton-miles (freight rail, air, and domestic shipping).
- The steepest decline in energy intensity is in the transportation sector, with the level of energy used per highway vehicle-mile traveled declining by 32% from 2018 to 2050 as a result of increasingly stringent fuel economy and energy efficiency standards for light- and heavy-duty vehicles.

Across end-use sectors, carbon dioxide intensity declines with changes in the fuel mix—

Carbon dioxide intensity by end-use sector (Reference case)
metric tons of carbon dioxide per billion British thermal units



Carbon dioxide intensity by end-use sector (Reference case)
metric tons of carbon dioxide per billion British thermal units



Note: Carbon dioxide intensities are calculated as carbon dioxide emissions per unit energy output (in British thermal units).

—despite overall increases in energy consumption

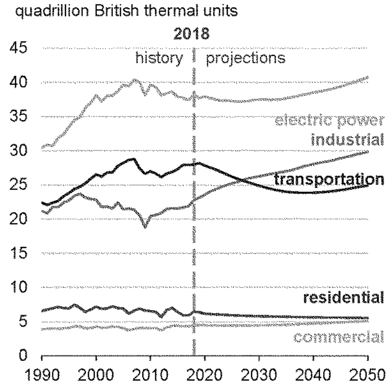
- Carbon dioxide (CO2) intensity can vary greatly depending on the mix of fuels the end-use sectors consume. Historically, the industrial sector has had the lowest CO2 intensity, as measured by CO2 emissions per British thermal unit (Btu). The transportation sector historically has had the highest CO2 intensity, which continues in the projection because carbon-intensive petroleum remains the dominant fuel used in vehicles throughout the projection period.

- The generation fuel mix in the electric power sector has changed since the mid-2000s, with lower generation from high-carbon intensive coal and higher generation from natural gas and carbon-free renewables, such as wind and solar. This change resulted in the overall CO2 intensity of the electric power sector declining by 25% from the mid-2000s to 2018 and continuing to decline through 2050.

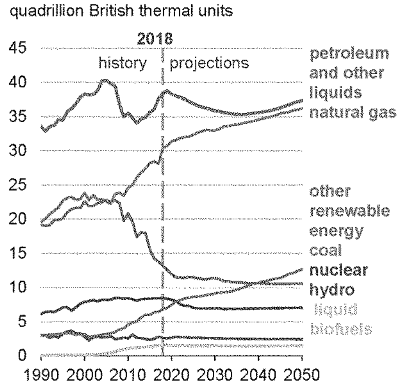
- Accounting for the CO2 emissions from the electricity sector in the end-use sectors that consume the electricity results in larger declines in CO2 intensity across those sectors for all AEO2019 cases. In the Reference case, the CO2 intensities of the residential and commercial sectors decline less than 1% when only their direct CO2 intensities are counted. When the electric power sector energy is distributed to the end-use sectors, the residential and commercial sectors decline by 11% and 10%, respectively, while the industrial sector declines by 11%. Transportation carbon intensity declines by 5%.

Policy, technology, and economics affect the mix of U.S. fuel consumption—

Energy consumption by sector (Reference case)
quadrillion British thermal units



Energy consumption by fuel (Reference case)
quadrillion British thermal units



—which affects energy consumption patterns throughout the projection period

- In all cases, non-hydroelectric renewables consumption grows the most (on a percentage basis). Implementing policies at the state level (renewable portfolio standards) and at the federal level (production and investment tax credits) has encouraged the use of renewables. Growing renewable use has driven down the costs of renewables technologies (wind and solar photovoltaic), further supporting their expanding adoption by the electric power and buildings sectors.

- Natural gas consumption rises as well, driven by projected low natural gas prices. In the Reference case, the industrial sector becomes the largest consumer of natural gas starting in the early 2020s. This sector will expand the use of natural gas as feedstock in the chemical industries and as lease and plant fuel, for industrial heat and power, and for liquefied natural gas production. Natural gas consumption for electric power also increases significantly in the power sector in response to low natural gas prices and to installing lower cost natural gas-fired combined-cycle generating units.

- The transportation sector is the largest consumer of petroleum and other liquids, particularly motor gasoline and distillate fuel oil. Current fuel economy standards stop requiring additional efficiency increases in 2025 for light-duty vehicles and in 2027 for heavy-duty vehicles, but travel continues to rise, and as a result, consumption of petroleum and other liquids increases later in the projection period.

Critical drivers and model updates

Many factors influence the model results in AEO2019, including varying assumptions about domestic energy resources and production technology; global oil prices; macroeconomic growth; model improvements; and new and existing laws and regulations since AEO2018.

Critical drivers and uncertainty

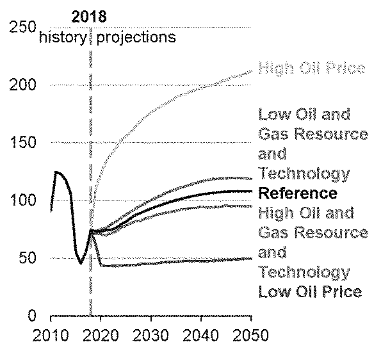
- Future oil prices are highly uncertain and are subject to international market conditions influenced by factors outside of the National Energy Modeling System. The High and Low Oil Price cases represent international conditions that could collectively drive prices to extreme, sustained deviations from the Reference case price path. Compared with the Reference case, in the High Oil Price case, non-U.S. demand is higher and non-U.S. supply is lower; in the Low Oil Price case, the opposite is true.

- Projections of tight oil and shale gas production are uncertain because large portions of the known formations have relatively little or no production history, and extraction technologies and practices continue to evolve rapidly. In the High Oil and Gas Resource and Technology case, lower production costs and higher resource availability than in the Reference case allow for higher production at lower prices. In the Low Oil and Gas Resource and Technology case, assumptions of lower resources and higher production costs are applied. These assumptions are not extended outside the United States.

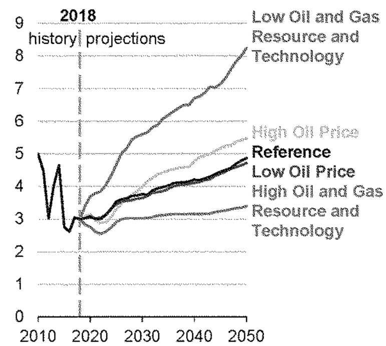
- Economic growth particularly affects energy consumption, and those effects are addressed in the High and Low Economic Growth cases, which modify population growth and productivity assumptions throughout the projection period to yield higher or lower compound annual growth rates for U.S. gross domestic product than in the Reference case.

Oil and natural gas prices are affected by assumptions about international supply and demand and the development of U.S. shale resources—

North Sea Brent oil price
2018 dollars per barrel



Natural gas price at Henry Hub
2018 dollars per million British thermal unit



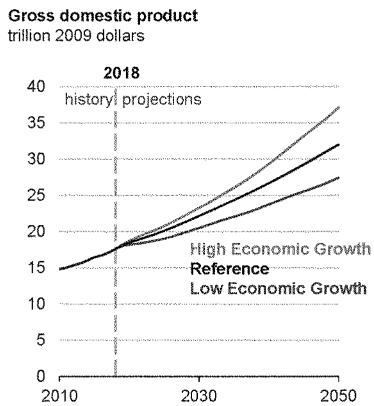
—with global conditions more important for oil prices and assumptions about resource and technology more important for natural gas

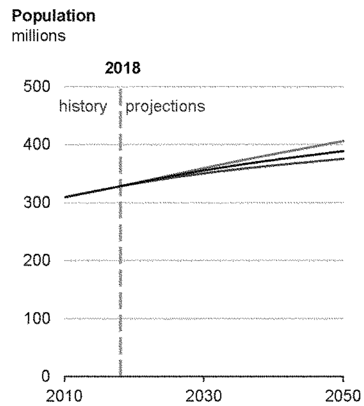
- Crude oil prices are influenced more by international markets than by assumptions about domestic resources and technological advances. In the High Oil Price case, the price of Brent crude oil, in 2018 dollars, is projected to reach $212 per barrel (b) by 2050 compared with $108/b in the Reference case and $50/b in the Low Oil Price case.

- Natural gas prices are highly sensitive to factors that drive supply, such as domestic resource and technology assumptions, and less dependent on the international conditions that drive oil prices. In the High Oil and Gas Resource and Technology case, Henry Hub natural gas prices remain near $3 per million British thermal units ($/MMBtu) throughout the projection period, while in the Low Oil and Gas Resource and Technology case they rise to more than $8/MMBtu.

- Across most cases, by 2050, consumption of natural gas increases even as production expands into more expensive-to-produce areas, putting upward pressure on production costs.

Economic growth side cases explore the uncertainty in macroeconomic assumptions inherent in future economic growth trends—





—which also affect important drivers of energy demand growth

- The Reference, High Economic Growth, and Low Economic Growth cases illustrate three possible paths for U.S. economic growth. In the High Economic Growth case, average annual growth in real gross domestic product (GDP) is 2.4% from 2018 to 2050, compared with 1.9% in the Reference case. The Low Economic Growth case assumes a lower rate of annual growth in real GDP of 1.4%.
- Differences among the cases reflect different assumptions for growth in the labor force, capital stock, and productivity. These changes affect capital investment decisions, household formation, industrial activity, and amounts of travel.
- All three economic growth cases assume expectations of smooth economic growth and do not anticipate business cycles or large economic shocks.

Significant data and model updates

- EIA released data from its 2015 *Residential Energy Consumption Survey* (RECS) in May 2018, and introduced estimates of energy consumption for an expanded list of energy end uses. Incorporating these updated estimates resulted in revised total housing units and end-use energy consumption shares.

- EIA updated residential and commercial technology efficiency and cost characteristics for space heating, space cooling, water heating, cooking equipment, and appliances based on reports Navigant Consulting, Inc. prepared for EIA.

- EIA updated vehicle stock data and related inputs such as vehicle scrappage and annual travel by vintage, which affected stock fuel economy and vehicle-miles traveled. Along with improved modeling of fleet-operated automated vehicles, these changes resulted in higher estimates of the number of light-duty vehicles on the road and higher vehicle-miles traveled.

New laws and regulations reflected in the Reference case as of October 2018

- EIA updated its modeling of the Annex VI of the International Convention for the Prevention of Pollution from Ships (MARPOL Convention), which limits sulfur emissions to 0.5% by weight, compared with the current 3.5% by weight, for ocean-going ships by 2020. The new modeling reflects expectations that U.S. refiners will supply a larger share of the low-sulfur fuel market. EIA also lowered the initial penetration of marine scrubbers and added a 60/40 blend of high sulfur fuel oil and distillate as a 2020 global sulfur-compliant fuel.

- In December 2017, Congress enacted the Tax Cuts and Jobs Act of 2017 (P.L. 115-97). Although this act is mainly associated with reducing the maximum marginal tax rate for corporations from 38% to 21% and temporarily allowing immediate expensing of major capital expenditures, it also established an oil and natural gas program for the leasing, development, production, and transportation of oil and natural gas in and from the coastal plain (1002 Area) of the Arctic National Wildlife Refuge (ANWR). Modeling the opening of ANWR to drilling increases Alaskan crude oil production after 2030.

New laws and regulations reflected in the Reference case as of October 2018 (continued)

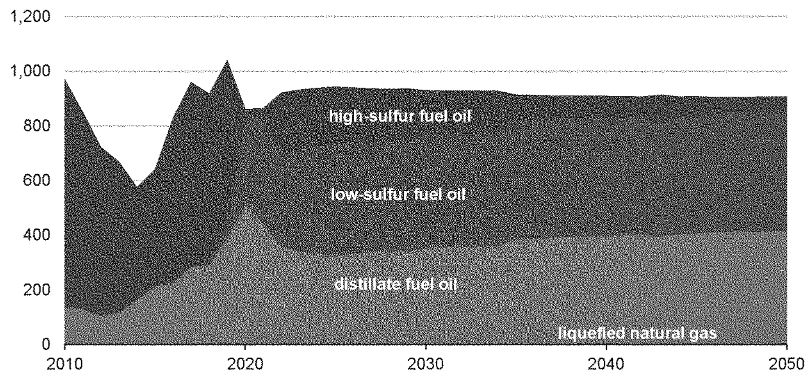
- The Internal Revenue Service issued safe harbor guidance for solar facilities to qualify for the Investment Tax Credit (ITC) as it phases down from 30% to 10% after 2020. Under the new guidance, utility-scale solar photovoltaic (PV) projects starting construction before January 1, 2020, have up to four years to bring the plant online, while still qualifying for the full 30% ITC. Projects entering service after January 1, 2024, receive a 10% ITC, including those starting construction after 2020. Modeling the safe harbor guidance results in later additions of solar PV systems as developers postpone in-service dates and in higher total solar PV builds.

- A number of new state and regional policies were enacted in the past year. These policies included California's requirement for 100% clean energy generation by 2045 and New Jersey's and Massachusetts's increased renewable portfolio standard (RPS) requirements that renewables contribute 50% and 35% of generation, respectively, by 2030. Even with the stricter requirements, EIA projects compliance to be easily met.

- EIA did not include the effects of the existing 45Q federal tax credits for carbon capture and sequestration in AEO2019 because the credits, although recently doubled, still do not appear large enough to encourage substantial market penetration of carbon capture in the scenarios modeled.

New limit on global sulfur emissions affects refinery operations and maritime transport—

International marine shipping fuel consumption (Reference case)
trillion British thermal units



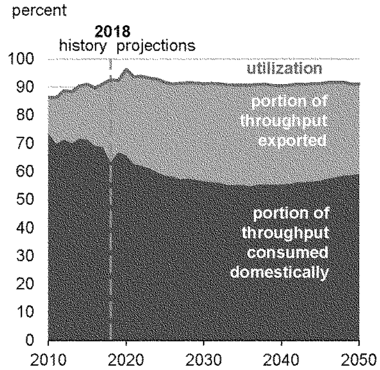
—as refiners and marine transporters adapt to meet the new requirements

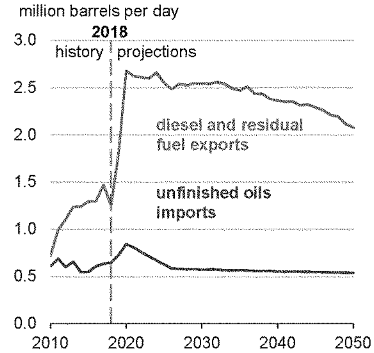
- Annex VI of the International Convention for the Prevention of Pollution from Ships (MARPOL Convention) limits emissions for ocean-going ships by 2020 (IMO 2020). From January 1, 2020, the limit for sulfur in fuel used on board ships operating outside designated emission control areas will be reduced to 0.5% m/m (mass by mass), a reduction of more than 85% from its present level of 3.5% m/m. Ships can meet the new global sulfur limit by installing pollutant-control equipment (scrubbers); by using a low-sulfur, petroleum-based marine fuel; or by switching to an alternative non-petroleum fuel such as liquefied natural gas (LNG).

- Shippers that install scrubbers have remained limited, and refineries continue to announce plans to upgrade high-sulfur fuel oils into higher quality products and increase availability of low-sulfur compliant fuel oils. Some shippers have also announced plans to address the costs associated with higher quality fuels by shifting those costs to their customers.

- Although some price swings and fuel availability issues are expected when the regulations take effect in 2020, by 2030 more than 83% of international marine fuel purchases in U.S. ports are for low-sulfur compliant fuel in the Reference case, and the share of LNG increases from negligible levels in 2018 to 7% in 2030.

Refinery utilization in the Reference case peaks in 2020—



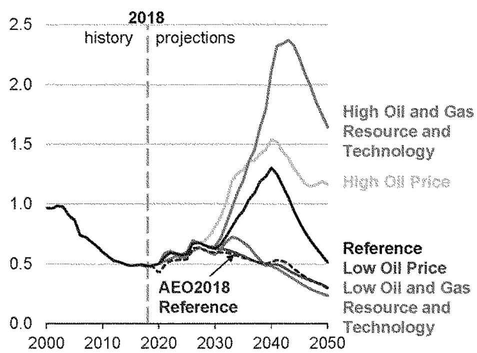


—as a result of sulfur emissions regulations that take effect in 2020

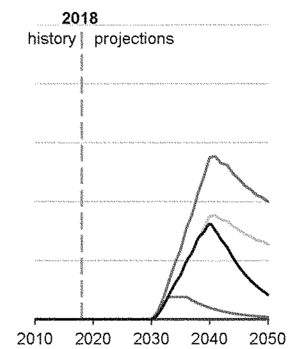
- U.S. refinery utilization peaks in most cases in 2020 as complex refineries in the United States that can process high-sulfur fuel oil in downstream units take advantage of the increased price spread between light and heavy crude oil. In the Reference case, refinery utilization peaks at 96% in 2020, gradually decreases between 2020 and 2026, and remains between 90% and 92% for the rest of the projection.
- The share of U.S. refinery throughput that is exported increases as more petroleum products are exported from 2020 to 2036 and as domestic consumption of refined products decreases. The trend reverses after 2036 when domestic consumption (especially of gasoline) increases.
- Imports of unfinished oils peak in 2020 as U.S. refineries take advantage of the increased discount of the heavy, high-sulfur residual fuel oil available on the global market.

Development of the Arctic National Wildlife Refuge increases Alaskan crude oil production in AEO2019—

Alaskan crude oil production
million barrels per day



ANWR crude oil production
million barrels per day



—but only after 2030 because of the time needed to acquire leases and develop infrastructure

- The passage of Public Law 115-97 required the Secretary of the Interior to establish a program to lease and develop oil and natural gas from the coastal plain (1002 Area) of the Arctic National Wildlife Refuge (ANWR). Previously, ANWR was effectively under a drilling moratorium.

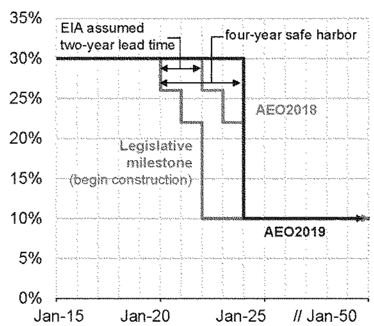
- Opening ANWR is not expected to have a significant impact on crude oil production before the 2030s because of the time needed to acquire leases, explore, and develop the required production infrastructure. Alaskan crude oil production in AEO2019 is 90% higher (3.2 billion barrels) from 2031 to 2050 than previously forecasted for that period in last year's AEO Reference case.

- The ANWR projections are highly uncertain because of several factors that affect the timing and cost of development, little direct knowledge of the resource size and quality that exists in ANWR, and inherent uncertainty about market dynamics. Cumulative ANWR crude oil production from 2031 to 2050 is 6.8 billion barrels, 0.7 billion barrels, and zero in the High Oil and Gas Resource and Technology, Low Oil and Gas Resource and Technology, and Low Oil Price cases, respectively.

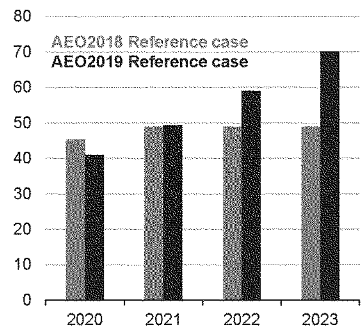
- A more in-depth analysis exploring the effect of this law on U.S. crude oil production projections was published in May 2018 as part of the AEO2018 *Issues in Focus* series.

Recently issued IRS guidance effectively eliminates the Investment Tax Credit phasedown in AEO2019—

Tax credit assumptions for utility-scale solar
percentage of installed cost



Power sector solar photovoltaic installed capacity
gigawatts

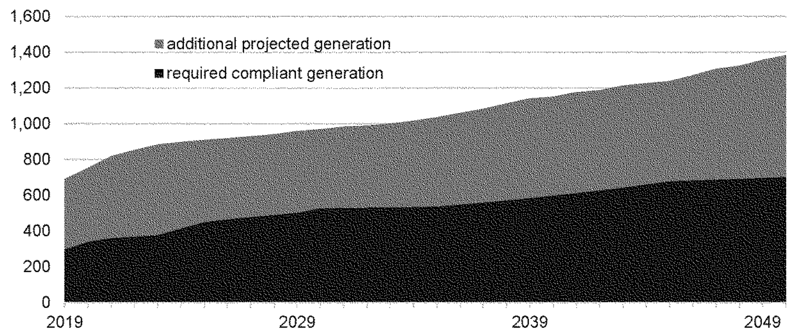


—increasing projected photovoltaic capacity in the near term

- In June 2018, the Internal Revenue Service (IRS) issued safe harbor guidance for solar facilities to qualify for the Investment Tax Credit (ITC).
- Under current law, utility-scale solar plants that are under construction before January 1, 2020, receive the full 30% ITC, while those under construction before January 1, 2021, receive a 26% ITC and those under construction before January 1, 2022, receive a 22% ITC. For AEO2018, before the IRS issued its guidance, EIA assumed a two-year construction lead time for new solar photovoltaic (PV) plants, so that PV plants entering service in 2023 received a 22% ITC.
- With the new IRS guidance, EIA assumes that utility-scale solar plants starting construction before January 1, 2020, and entering service before January 1, 2024, receive the full 30% ITC. This assumption results in 21 gigawatts of additional solar PV capacity coming online before January 1, 2024, in AEO2019 as compared with AEO2018.
- The figure shown above applies to utility-owned solar PV installations. Residential systems individuals own have a different treatment under the ITC, and systems that commercial or other non-utility entities own have different financial considerations, and so are not shown above.

Renewable generation exceeds requirements for state renewable portfolio standards—

Total qualifying renewable generation required for combined state renewable portfolio standards and projected total achieved 2019-2050
billion kilowatthours



—even with recent increases in several states' standards

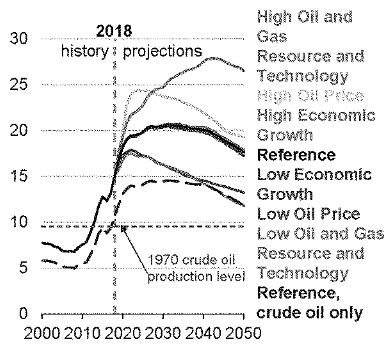
- California, New Jersey, and Massachusetts enacted new policies since AEO2018 to increase renewable and/or non-emitting electric generation and, in New Jersey, to support operation of existing nuclear generators.
- The combined generation required to comply with all U.S. state-level renewable portfolio standards (RPS) is 704 billion kilowatthours by 2050, but compliant renewable generation collectively exceeds these requirements in all AEO2019 cases in 2050, nearly double the requirement for 2050 in the Reference case.
- Near-term expiration of tax credits for wind and solar photovoltaics (PV) spurs installation of these generating technologies through 2024. The continued decline in solar PV costs throughout the projection period encourages new additions beyond the existing RPS requirements.
- For AEO2019, pending formal rulemaking, EIA assumed that the 100% clean energy standard recently adopted in California also includes nuclear, large-scale hydroelectric, and fossil-fired plants with carbon sequestration as qualifying generation.

Petroleum and other liquids

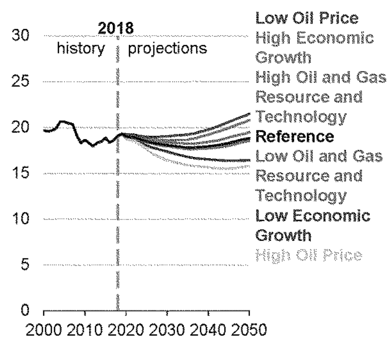
U.S. crude oil and natural gas plant liquids production continues to grow as a result of the further development of tight oil resources during the projection period. During the same period, domestic consumption falls, making the United States a net exporter of liquid fuels in the Reference case.

U.S. crude oil and natural gas plant liquids production continues to increase through 2022 in all cases with crude oil exceeding its previous peak 1970 level in 2018—

U.S. crude oil and natural gas plant liquids production
million barrels per day



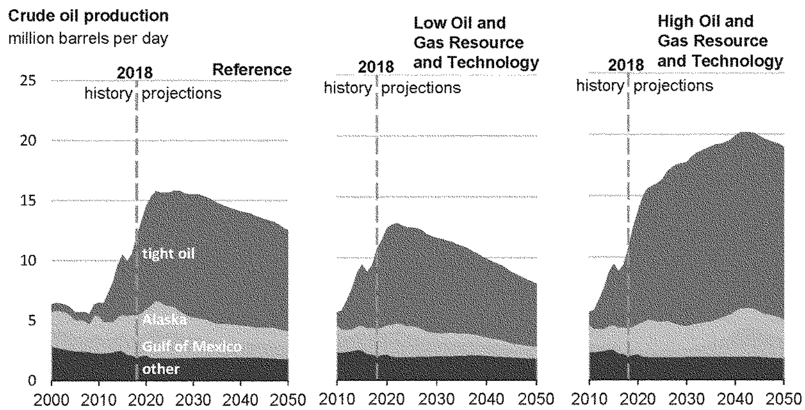
Petroleum and other liquids consumption
million barrels per day



—while consumption declines to lower than its 2004 peak level through 2050 in most cases

- In the Reference case, U.S. crude oil production continues to grow through 2030 and then plateaus at more than 14.0 million barrels per day (b/d) until 2040.
- With continuing development of tight oil and shale gas resources, natural gas plant liquids (NGPL) production reaches the 6.0 million b/d mark by 2030, a 38% increase from the 2018 level.
- Total liquids production varies widely under different assumptions about resources, technology, and oil prices. The size of resources and the pace of technology improvements to lower production costs translate directly to long-term total production. Much higher oil prices can boost near-term production but cannot sustain the higher production pace. Production is less variable in the economic growth cases because domestic wellhead prices are less sensitive to macroeconomic growth assumptions.
- Consumption of petroleum and other liquids is less sensitive to varying assumptions about resources, technology, and oil prices. With higher levels of economic activity and relatively low oil prices, consumption of petroleum and other liquids increases in the High Economic Growth and Low Oil Price cases, while consumption remains comparatively flat or decreases in the other cases.

Tight oil development drives U.S. crude oil production from 2018 to 2050—



—a result consistent across all side cases

- Lower 48 onshore tight oil development continues to be the main driver of total U.S. crude oil production, accounting for about 68% of cumulative domestic production in the Reference case during the projection period.

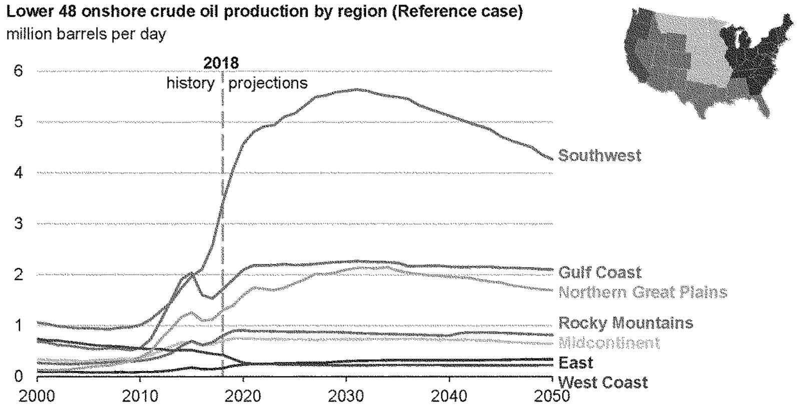
- U.S. crude oil production levels off at about 14 million barrels per day (b/d) through 2040 in the Reference case as tight oil development moves into less productive areas and well productivity declines.

- In the Reference case, oil and natural gas resource discoveries in deepwater in the Gulf of Mexico lead Lower 48 states offshore production to reach a record 2.4 million b/d in 2022. Many of these discoveries resulted from exploration when oil prices were higher than $100 per barrel before the oil price collapse in 2015 and are being developed as oil prices rise. Offshore production then declines through 2035 before flattening through 2050 as a result of new discoveries offsetting declines in legacy fields.

- Alaska crude oil production increases through 2030, driven primarily by the development of fields in the National Petroleum Reserve–Alaska (NPR-A), and after 2030, the development of fields in the 1002 Section of the Arctic National Wildlife Refuge (ANWR). Exploration and development of fields in ANWR is not economical in the Low Oil Price case.

The Southwest region leads tight oil productiongrowth in the United States in the Reference case—

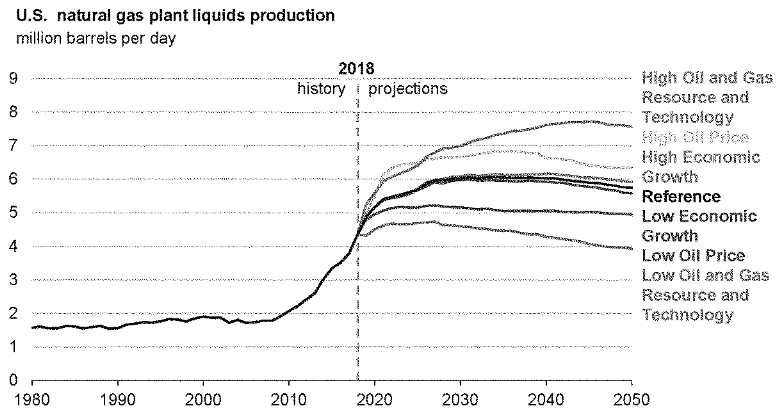
Lower 48 onshore crude oil production by region (Reference case)
million barrels per day



—but the Gulf Coast and Northern Great Plains regions also contribute

- Growth in Lower 48 onshore crude oil production occurs mainly in the Permian Basin in the Southwest region. This basin includes many prolific tight oil plays with multiple layers, including the Bone Spring, Spraberry, and Wolfcamp, making it one of the lower-cost areas to develop.
- Northern Great Plains production grows into the 2030s, driven by increases in production from the Bakken and Three Forks tight oil plays.
- Production in the Gulf Coast region increases through 2021 before flattening out as the decline in production from the Eagle Ford is offset by increasing production from other tight/shale plays such as the Austin Chalk.

Natural gas plant liquids production increases in most AEO cases—



—because of higher levels of drilling in liquid-rich natural gas formations and increased demand

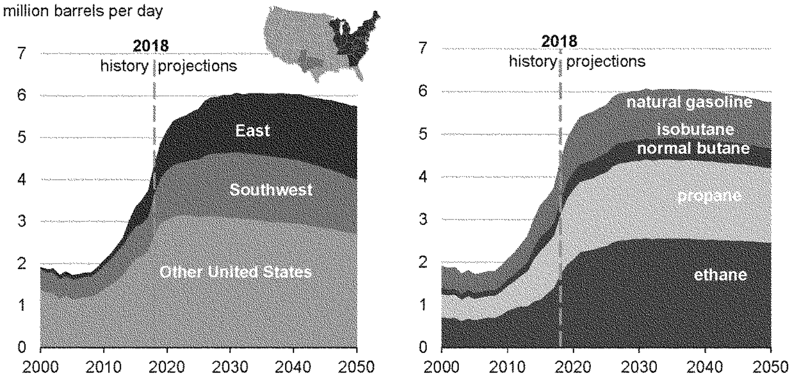
- In the Reference case, natural gas plant liquids (NGPL) production grows by 32% between 2018 and 2050 as a result of demand increases in the global petrochemical industry.

- Most NGPL production growth in the Reference case occurs before 2025 as producers focus on natural gas liquids-rich plays, where NGPL-to-gas ratios are highest and increased demand spurs higher ethane recovery.

- NGPL production is sensitive to changes in resource and technology assumptions. In the High Oil and Gas Resource and Technology case, which has higher rates of technological improvement, higher recovery estimates, and additional tight oil and shale gas resources, NGPL production grows by 73% between 2018 and 2050. In contrast, in the Low Oil and Gas Resource and Technology, which has lower rates of technological improvement and lower recovery estimates, NGPL production declines by 10% between 2018 and 2050.

The East and Southwest regions lead production of natural gas plant liquids in the Reference case—

U.S. natural gas plant liquids production (Reference case)
million barrels per day

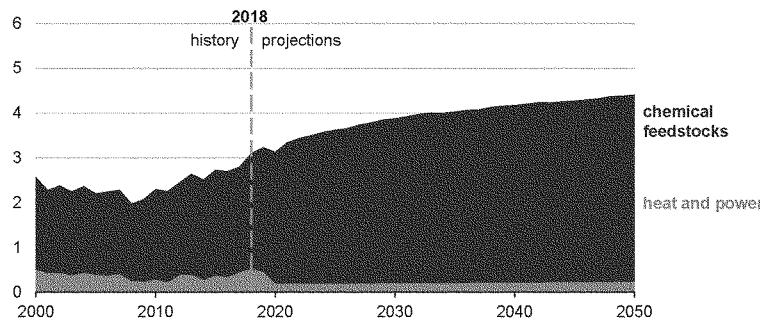


—as development focuses on tight plays with low production costs and easy access to markets

- Natural gas plant liquids (NGPL) are light hydrocarbons predominantly found in natural gas wells and diverted from the natural gas stream by natural gas processing plants. These hydrocarbons include ethane, propane, normal butane, isobutane, and natural gasoline.
- The large increase in NGPL production in the Reference case in the East (Marcellus and Utica plays) and Southwest (Permian plays) during the next 10 years is mainly caused by the close association NGPLs have with the development of crude oil and natural gas resources. By 2050, the Southwest and East regions account for more than 50% of total U.S. NGPL production.
- NGPLs are used in many different ways. Ethane is used almost exclusively for petrochemicals. Approximately 40% of propane is used for petrochemicals, and the remainder is used for heating, grain drying, and transportation. Approximately 60% of butanes and natural gasoline are used for blending with motor gasoline and fuel ethanol, and the remainder is used for petrochemicals and solvents.
- The shares of NGPL components in the Reference case are relatively stable during the entire projection period (2018 to 2050), with ethane and propane contributing about 42% and 30%, respectively, to the total volume.

Most natural gas liquids in the Reference case serve as feedstocks to the bulk chemical industry—

U.S. industrial NGL consumption (Reference case)
quadrillion British thermal units

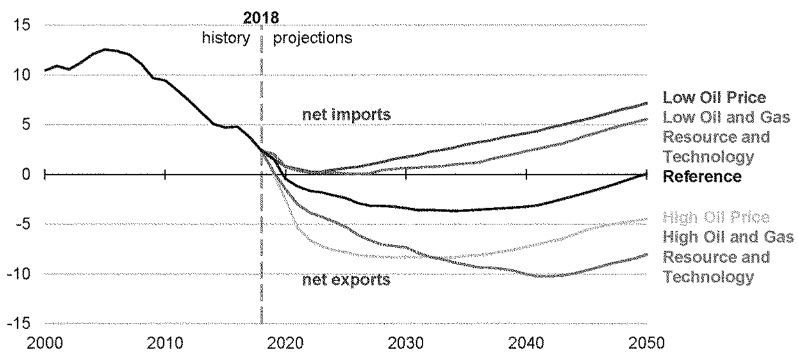


—although a small proportion is also used as fuel

- Consumption of ethane, propane, and butane used as bulk chemical feedstock grows an average of 1.5% per year between 2018 and 2050 in the Reference case, compared with 3.1% per year from 2010 to 2018.
- The consumption of natural gas liquids (NGL) as feedstock grows faster in the High Economic Growth case (1.9% per year) and the High Resource and Technology case (1.8% per year). In the High Economic Growth case, demand for all goods is higher than in the Reference case, including bulk chemicals for domestic use and export. In the High Resource and Technology case, NGL are more abundant and less expensive. As a result, shipments of bulk chemicals are greater.
- Most NGL feedstock is ethane, which is processed almost exclusively into ethylene, a building block for plastics, resins, and other industrial products. Propane, normal butane, and isobutane are also used to produce propylene and butadiene, respectively, but in much smaller quantities compared with ethane.
- Propane is used in the agriculture sector for grain drying and heating and in the construction industry for heating and for powering vehicles and equipment.

In the Reference case, the United States becomes a net exporter of petroleum on a volume basis from 2020 to 2049—

U.S. petroleum and other liquids net imports/exports
million barrels per day



—but side case results vary significantly using different assumptions

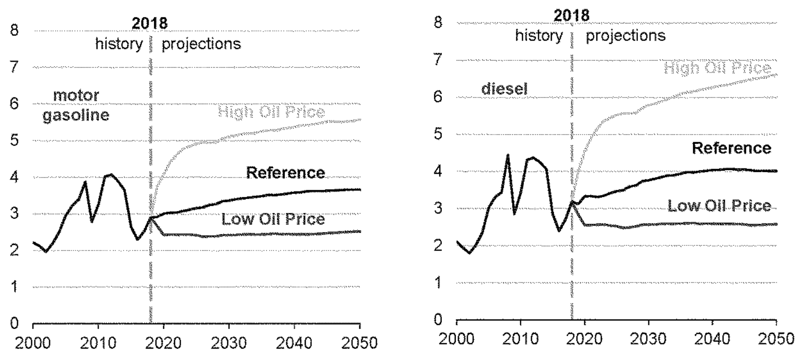
- Net U.S. imports of crude oil and liquid fuels will fall between 2018 and 2034 in the Reference case as strong production growth and decreasing domestic demand result in the United States becoming a net exporter.

- In the Reference case, net exports from the United States peak at more than 3.68 million barrels per day (b/d) in 2034 before gradually reversing as domestic consumption rises. The United States returns to being a net importer in 2050 on a volume basis.

- Additional resources and higher levels of technological improvement in the High Oil and Gas Resource and Technology case results in higher crude oil production and higher exports, with exports reaching a high of 10.26 million b/d in 2041. Projected net exports reach a high of 8.39 million b/d in 2033 in the High Oil Price case as a result of higher prices that support higher domestic production. Conversely, low oil prices in the Low Oil Price case drive projected net imports up from 2.37 million b/d in 2018 to 7.17 million b/d in 2050.

In the Reference case, motor gasoline and diesel fuel prices rise after 2018 throughout the projections—

Retail prices of selected petroleum products
2018 dollars per gallon



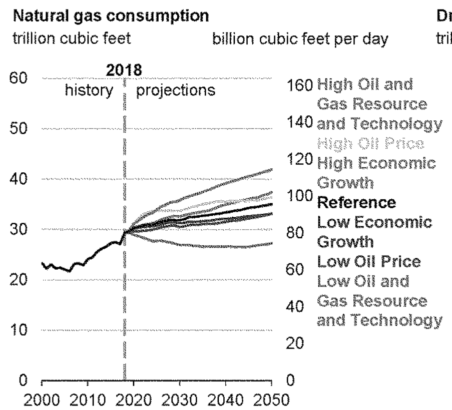
—but neither price returns to previous peaks

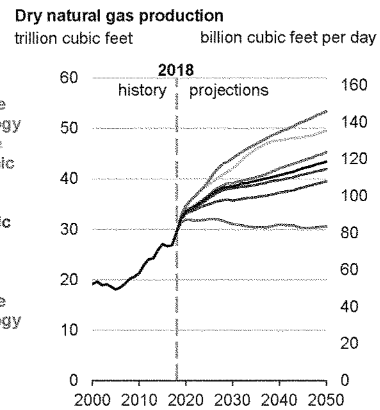
- In the Reference case, motor gasoline and diesel fuel retail prices increase by 76 cents per gallon and 82 cents per gallon, respectively, from 2018 to 2050, largely because of increasing crude oil prices.
- Implementing the International Maritime Organization sulfur regulations in 2020 triggers short-term price increases because the refinery and maritime shipping industries must adjust fuel specifications and consumption. These effects peak in 2020 and gradually fade out of the market by 2026.
- The recent trend of an increasing price spread between diesel fuel and motor gasoline retail prices continues in the Reference case through 2038, in part, because of strong growth in domestic diesel fuel demand and declining demand for gasoline.
- Motor gasoline and diesel fuel retail prices move in the same direction as crude oil prices in the High and Low Oil Price cases. Motor gasoline retail prices in 2050 range from $5.57 per gallon in the High Oil Price case to $2.51 per gallon in the Low Oil Price case. Diesel fuel retail prices range from $6.61 per gallon in the High Oil Price case to $2.57 per gallon in the Low Oil Price case in 2050.

Natural gas

Natural gas experiences the largest production increase of all fossil fuels during the projection period across all cases, driven by continued development of lower-cost shale gas and tight oil resources. The growth in natural gas production supports increasing domestic consumption, particularly in the industrial and electric power sectors, and higher levels of natural gas exports.

U.S. dry natural gas consumption and production increase in most cases—





—with production growth outpacing natural gas consumption in all cases

- Natural gas production in the Reference case grows 7% per year from 2018 to 2020, which is more than the 4% per year average growth rate from 2005 to 2015. However, after 2020, growth slows to less than 1% per year as growth in both domestic consumption and demand for U.S. natural gas exports slows.

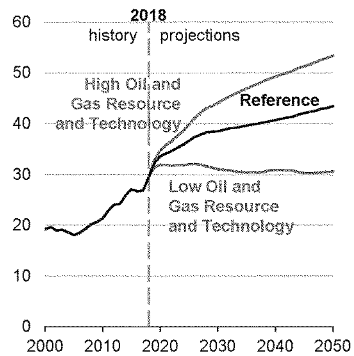
- Across the Reference and all sensitivity cases, recent historical and near-term natural gas production growth in an environment of relatively low and stable prices supports growing demand from large natural gas- and capital-intensive projects currently under construction, including chemical projects and liquefaction export terminals.

- After 2020, production grows at a higher rate than consumption in most cases, leading to a corresponding growth in U.S. exports of natural gas to global markets. The exception is in the Low Oil and Gas Resource and Technology case, where production, consumption, and net exports all remain relatively flat as a result of higher production costs.

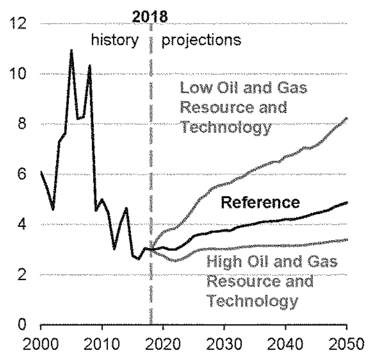
- The Low Oil and Gas Resource and Technology case, which has the highest natural gas prices relative to the other cases, is the only case where U.S. natural gas consumption does not increase during the projection period.

Natural gas prices depend on resource and technology assumptions—

Dry natural gas production
trillion cubic feet



Natural gas spot price at Henry Hub
2018 dollars per million British thermal unit



—and Henry Hub prices in the AEO2019 Reference case remain lower than $5 per million Btu throughout the projection period

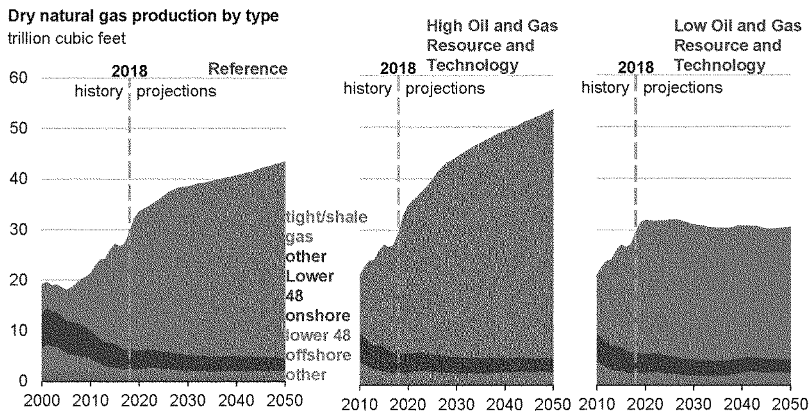
- In the Reference case, growing demand in domestic and export markets leads to increasing natural gas spot prices at the U.S. benchmark Henry Hub during the projection period in the Reference case despite continued technological advances that support increased production.

- To satisfy the growing demand for natural gas, production must expand into less prolific and more expensive-to-produce areas, putting upward pressure on production costs.

- Natural gas prices in the AEO2019 Reference case remain lower than $4 per million British thermal units (Btu) through 2035 and lower than $5 per million Btu through 2050 because of an increase in lower-cost resources, primarily in tight oil plays in the Permian Basin, which allows higher production levels at lower prices during the projection period.

- The High Oil and Gas Resource and Technology case, which reflects lower costs and higher resource availability, shows an increase in production and lower prices relative to the Reference case. In the Low Oil and Gas Resource and Technology case, high prices, which result from higher costs and fewer available resources, result in lower domestic consumption and exports during the projection period.

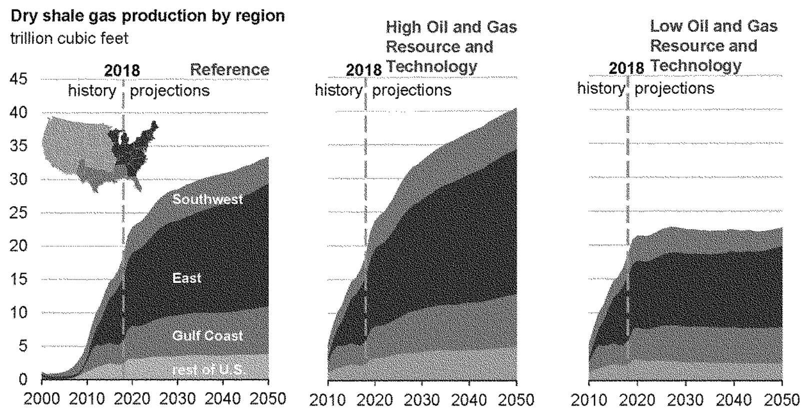
U.S. dry natural gas production increases as a result of continued development of tight and shale resources—



—which account for nearly 90% of dry natural gas production in 2050

- Natural gas production from shale gas and tight oil plays as a share of total U.S. natural gas production continues to grow in both share and absolute volume because of the sheer size of the associated resources, which extend over nearly 500,000 square miles, and because of improvements in technology that allow for the development of these resources at lower costs.
- In the High Oil and Gas Resource and Technology case, which has more optimistic assumptions regarding resource size and recovery rates, cumulative production from shale gas and tight oil is 18% higher than in the Reference case. Conversely, in the Low Oil and Gas Resource and Technology case, cumulative production from those resources is 24% lower.
- Across all cases, onshore production of natural gas from sources other than tight oil and shale gas, such as coalbed methane, generally continues to decline through 2050 because of unfavorable economic conditions for producing that resource.
- Offshore natural gas production in the United States remains nearly flat during the projection period in all cases as a result of production from new discoveries that generally offsets declines in legacy fields.

Eastern U.S. production of natural gas from shale resources leads growth in the Reference case—

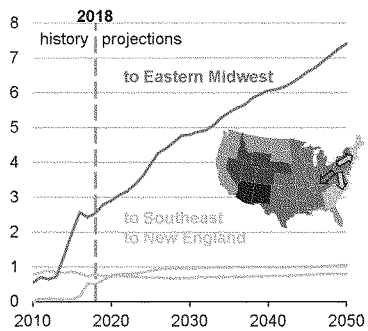


—followed by growth in Gulf Coast onshore production

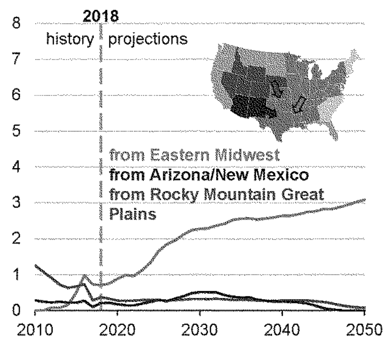
- Total U.S. natural gas production across most cases is driven by continued development of the Marcellus and Utica shale plays in the East.
- Natural gas from the Eagle Ford (co-produced with oil) and the Haynesville plays in the Gulf Coast region also contributes to domestic dry natural gas production.
- Associated natural gas production from tight oil production in the Permian Basin in the Southwest region grows strongly in the early part of the projection period but remains relatively flat after 2030.
- Technological advancements and improvements in industry practices lower production costs in the Reference case and increase the volume of oil and natural gas recovery per well. These advancements have a significant cumulative effect in plays that extend over wide areas and that have large undeveloped resources (Marcellus, Utica, and Haynesville).
- Natural gas production from regions with shale and tight resources show higher levels of variability across the resource and technology cases, compared with the Reference case because assumptions in those cases target those specific resources.

Natural gas production flows increase from the Mid-Atlantic and Ohio to the South Central through the Eastern Midwest—

Flows of natural gas from the Mid-Atlantic and Ohio (Reference case)
trillion cubic feet



Flows of natural gas to the South Central (Reference case)
trillion cubic feet



—as growth in domestic consumption and exports is concentrated in the Gulf Coast

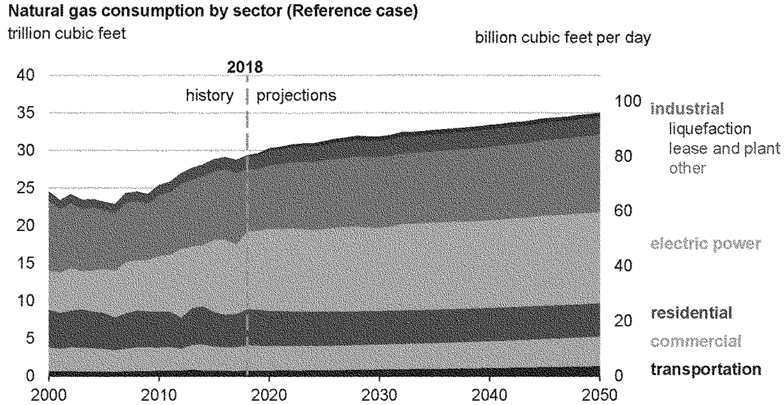
- Reference case growth of natural gas production in the Mid-Atlantic and Ohio region, from the Marcellus and Utica formations, continues the trend of more natural gas flowing out of the region. This trend continues the recent reversal of past flows, where natural gas from the South Central region—which includes Texas and the Gulf Coast—traditionally moved into the Northeast.

- Although historically a net supplier of natural gas to U.S. markets, the South Central region's demand growth outpaces production growth throughout the projection period. In addition to increased natural gas consumption in both the industrial and electric power sectors during the projection period in this region, U.S. natural gas exports to Mexico and U.S. liquefied natural gas exports from Gulf Coast facilities also rise. As a result, the Gulf Coast will become the fastest-growing demand market in the United States.

- To transport increased volumes of natural gas from the Mid-Atlantic and Ohio region to demand in the South Central region, additional natural gas pipeline capacity will be built from the Mid-Atlantic through the Eastern Midwest region.

Industrial and electric power demand drives natural gas consumption growth—

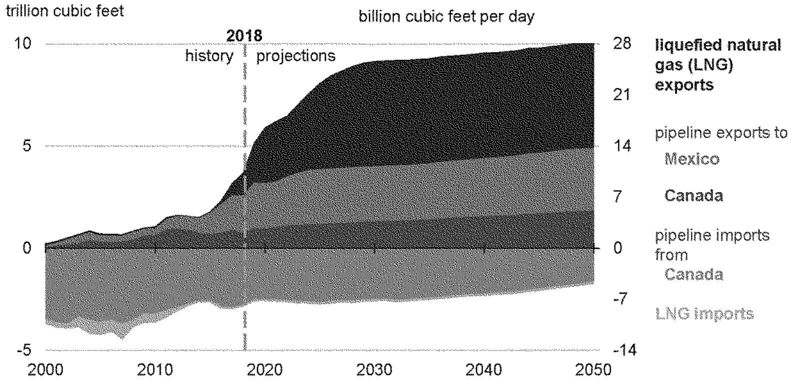
Natural gas consumption by sector (Reference case)



—while consumption in the residential and commercial sectors remains relatively flat across the projection period in the Reference case

- Natural gas prices that are relatively low compared with historical prices lead to growing use of natural gas across most end-use sectors.
- The industrial sector, which includes fuel used for liquefaction at export facilities and in lease and plant operations, is the largest consumer of natural gas in the Reference case. Major natural gas consumers in this sector include the chemical industry (where natural gas is used as a feedstock to produce methanol and ammonia), industrial heat and power, and lease and plant fuel.
- Natural gas used for electric power generation generally increases during the projection period but at a slower rate than in the industrial sector. This growth is supported by the scheduled expiration of renewable tax credits in the mid-2020s, as well as the retirement of coal-fired and nuclear generation capacity during the projection period.
- Natural gas consumption in the residential and commercial sectors remains largely flat because of efficiency gains and population shifts that counterbalance demand growth. Although natural gas use rises in the transportation sector, particularly for freight trucks and rail and marine shipping, it remains a small share of both transportation fuel demand and total natural gas consumption.

Net exports of natural gas from the United States continue to grow in the Reference case—



—because of near-term export growth and LNG export facilities delivering domestic production to global markets

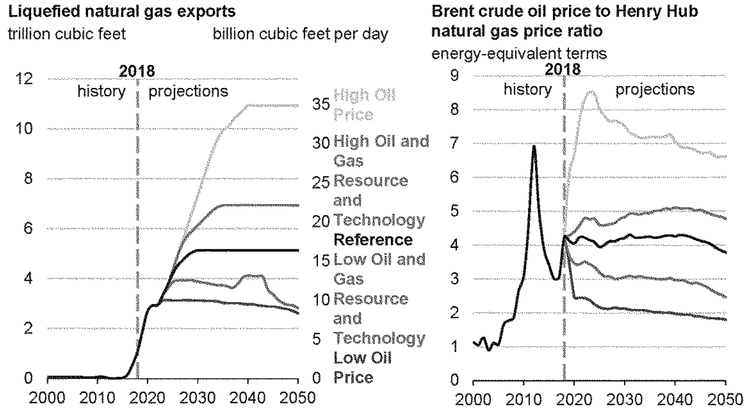
- In the Reference case, pipeline exports to Mexico and liquefied natural gas (LNG) exports increase until 2025, after which pipeline export growth to Mexico slows and LNG exports continue rising through 2030.

- Increasing natural gas exports to Mexico are a result of more pipeline infrastructure to and within Mexico, allowing for increased natural gas-fired power generation. By 2030, Mexican domestic natural gas production begins to displace U.S. exports.

- Three LNG export facilities were operational in the Lower 48 states by the end of 2018. After all LNG export facilities and expansions currently under construction are completed by 2022, LNG export capacity increases further as a result of growing Asian demand and U.S. natural gas prices remaining competitive. As U.S.-sourced LNG becomes less competitive, export volumes stop growing, remaining steady during the later years of the projection period.

- U.S. imports of natural gas from Canada, primarily from its prolific western region, continue their decline from historical levels. U.S. exports of natural gas to Eastern Canada continue to increase because of Eastern Canada's proximity to U.S. natural gas resources in the Marcellus and Utica plays and additional, recently built pipeline infrastructure.

U.S. LNG exports are sensitive to both oil and natural gas prices—



—resulting in a wide range of U.S. LNG export levels across cases

- Historically, most liquefied natural gas (LNG) was traded under long-term contracts linked to crude oil prices because the regional nature of natural gas markets prevented the development of a natural gas price index that could be used globally. In addition to providing a liquid pricing benchmark, crude oil to some degree can substitute for natural gas in industry and for power generation.

- When the crude oil-to-natural gas price ratio is highest, such as in the High Oil Price case, U.S. LNG exports are at their highest levels. U.S. LNG supplies have the advantage of being priced based on relatively low domestic spot prices instead of oil-linked contracts. Also, demand for LNG increases, in part, as a result of consumers moving away from petroleum products.

- In the High Oil and Gas Resource and Technology case, low U.S. natural gas prices make U.S. LNG exports competitive relative to other suppliers. Conversely, higher U.S. natural gas prices in the Low Oil and Gas Resource and Technology case result in lower U.S. LNG exports.

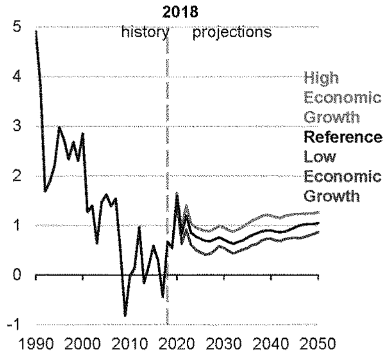
- As more natural gas is traded via short-term contracts or traded on the spot market, the link between LNG and oil prices weakens over time, making U.S. LNG exports less sensitive to the crude oil-to-natural gas price ratio and causing growth in U.S. LNG exports to slow in all cases.

Electricity

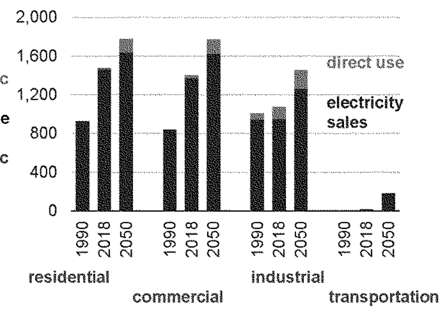
As electricity demand grows modestly, the primary drivers for new capacity in the Reference case are the retirements of older, less-efficient fossil fuel units, the near-term availability of renewable energy tax credits, and the continued decline in the capital cost of renewables, especially solar photovoltaic. Low natural gas prices and favorable costs for renewables result in natural gas and renewables as the primary sources of new generation capacity. The future generation mix is sensitive to the price of natural gas and the growth in electricity demand.

Electricity demand grows slowly through 2050 in the Reference case—

Electricity use growth rate
percent growth (three-year rolling average)



Electricity use by end-use demand sector (Reference case)
billion kilowatthours



—with increases occurring across all demand sectors

- Although near-term electricity demand increases or decreases as a result of year-to-year weather fluctuations, long-term projections typically assume long-term average weather patterns. As a result, economic growth tends to drive long-term demand trends offset by increases in energy efficiency. The annual growth in electricity demand averages about 1% throughout the projection period in the Reference case.

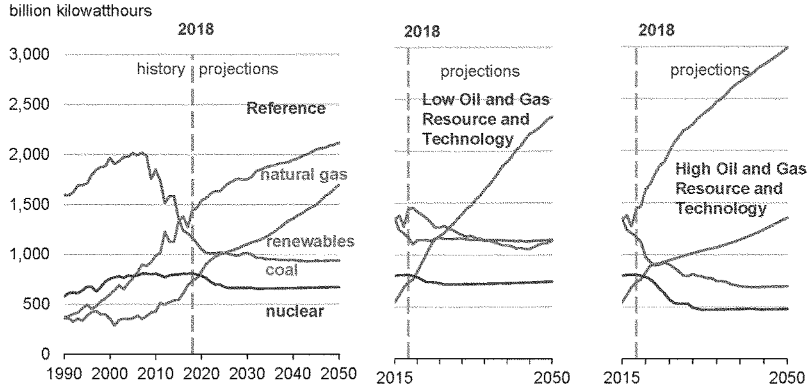
- Historically, electricity demand growth rates have slowed as new efficient devices and production processes replaced older, less-efficient appliances, heating, ventilation, cooling units, and capital equipment, even as the economy continued to grow.

- Average electricity growth rates in the High and Low Economic Growth cases vary the most from the Reference case. Electricity use in the High Economic Growth case grows about 0.2 percentage points faster on average as opposed to 0.2 percentage points slower in the Low Economic Growth case.

- The modest growth in projected electricity sales from 2018 to 2050 would be higher but for significant direct-use generation from rooftop photovoltaic (PV) systems primarily on residential and commercial buildings and combined heat and power systems in industrial and some commercial applications.

The abundance of natural gas supports its growth in the electric generation fuel mix—

Electricity generation from selected fuels
billion kilowatthours



—but the results are sensitive to resource and price assumptions

- Persistent low natural gas prices have decreased the competitiveness of coal-fired power generation. The 2017 coal-fired generation level was only about three-fifths of its peak in 2005. With relatively low natural gas prices throughout the projection period in the Reference case, natural gas-fired generation grows steadily and remains the dominant fuel in the electric power sector through 2050.

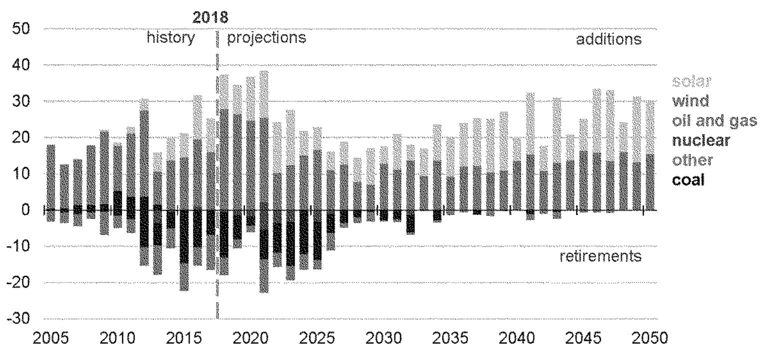
- Continued availability of renewable tax credits and declining capital costs for solar photovoltaic result in strong growth in non-hydro renewables generation. Increased natural gas-fired generation and renewables additions result in coal-fired generation slightly decreasing in the Reference case.

- In the Low Oil and Gas Resource and Technology case, renewables emerge as the primary source of electricity generation. Although higher natural gas prices increase utilization of the existing coal-fired generation fleet and prevent some coal-fired unit retirements, growth in coal-fired generation is muted by the lack of new capacity additions because of the relatively-high capital costs compared with other fuels.

- Lower projected natural gas prices in the High Oil and Gas Resource and Technology case support substantially higher natural gas-fired generation at the expense of renewables growth. In addition, coal-fired generation by 2050 is 26% lower than projected in the Reference case.

Expected requirements for new generating capacity will be met by renewables and natural gas—

Annual electricity generating capacity additions and retirements (Reference case)
gigawatts



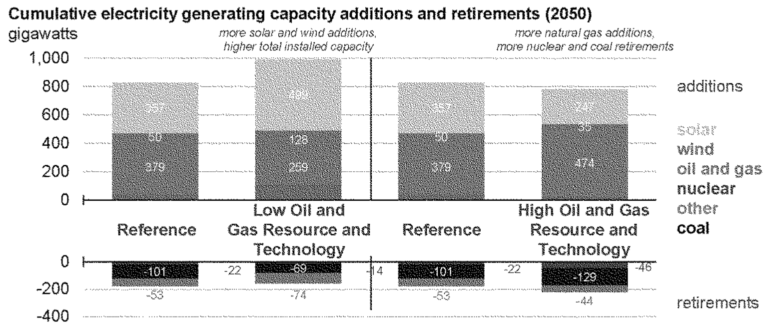
—as a result of declining costs and competiveness of natural gas

- In the Reference case, the United States adds 72 gigawatts (GW) of new wind and solar photovoltaic (PV) capacity between 2018 and 2021, motivated by declining capital costs and the availability of tax credits.

- New wind capacity additions continue at much lower levels after production tax credits expire in the early 2020s. Although the commercial solar Investment Tax Credits (ITC) decreases and the ITC for residential-owned systems expires, the growth in solar PV capacity continues through 2050 for both the utility-scale and small-scale applications because the cost of PV declines throughout the projection.

- Most electric generation capacity retirements occur by 2025 as a result of many regions that have surplus capacity and lower natural gas prices. The retirements reflect both planned and additional projected retirements of coal-fired capacity. On the other hand, new high-efficiency natural gas-fired combined-cycle and renewables generating capacity is added steadily through 2050 to meet growing electricity demand.

Long-term trends in electricity generation are dominated by solar and natural gas-fired capacity additions—

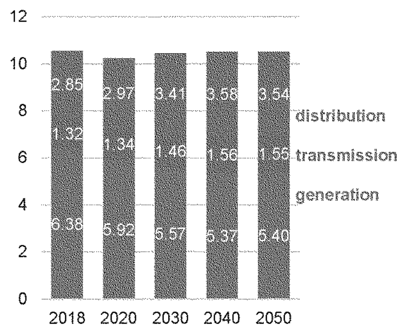


—with coal, nuclear, and less efficient natural gas generators contributing to capacity retirements

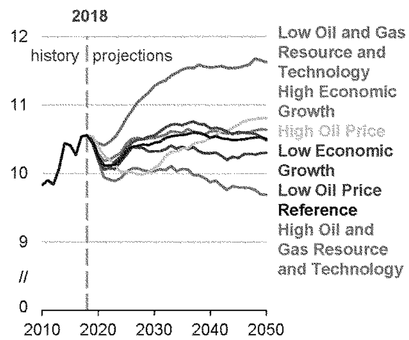
- In the Reference case, coal-fired generating capacity declines faster than coal-fired generation through 2050, with 101 gigawatts (GW) (or 42% of existing coal-fired capacity) projected to retire by 2050. For nuclear generators, 22 GW (22% of current nuclear capacity) retires by 2050 in the Reference case.
- From 2018 to 2021, wind builds play a more significant role in total capacity additions, accounting for 20% of the additions. Over time, solar generation grows for both the utility- and small-scale sectors. In the Reference case, 43% of total capacity additions through 2050 are solar photovoltaic capacity.
- In the Low Oil and Gas Resource and Technology case, the relatively higher natural gas prices support the build-out of wind and solar generating technologies instead of natural gas-fired additions. More total installed capacity is required because the wind and solar generator capacity factors are lower than for natural gas-fired combined-cycle units.
- Low natural gas prices resulting from higher-than-expected natural gas resources in the High Oil and Gas Resource and Technology case favor the installation of natural gas capacity (61% of the capacity added through 2050) instead of renewables (36% of capacity additions through 2050) and result in higher levels of coal and nuclear retirements compared with the Reference case.

Reference case electricity prices fall slightly, with dropping generation costs offset by rising transmission and distribution costs—

Electricity prices by service category (Reference case)
2018 cents per kilowatthours



Average electricity price
2018 cents per kilowatthour



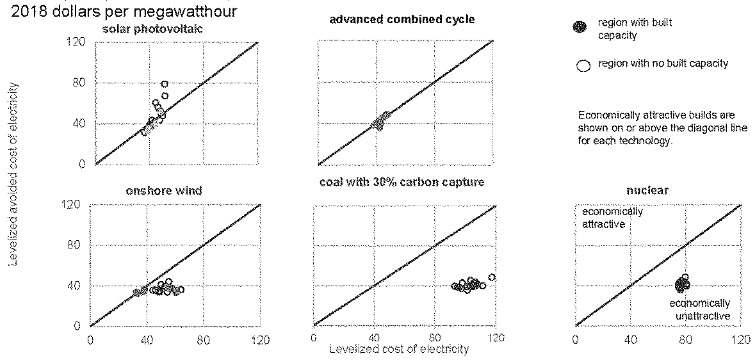
—while generation costs vary across the resource cases that influence the generation mix

- Average electricity prices vary considerably across scenarios mainly because of the effect natural gas prices have on the projections. By 2050, prices range from 9.7 cents/kilowatthours (kWh) to 11.6 cents/kWh across the High and Low Oil and Gas Resource and Technology cases.
- Generation costs, which account for the largest share of the price of electricity, decrease 15% from 2018 to 2050 in the Reference case. Generation costs in regulated markets (70% of the United States) reflect recovery of investment costs and fuel and operating costs. Investment costs decline over time as older capacity is retired and new, lower cost capacity is added. Fuel and operating costs are projected to remain flat as more efficient generators and renewables offsets long-term increases in fuel prices.
- Average electricity prices fall 4.2% from 2018 to 2022. This decline is driven by customer rebates from lower utility taxes associated with the Tax Cuts and Jobs Act of 2017, lower construction and operating costs of some new fossil and renewable plants, and the subsequent retirement of plants that were relatively more costly to operate.
- In the Reference case, transmission and distribution costs increase by 18% and 24%, respectively, as a result of replacing aging infrastructure and upgrading the grid to integrate wind and solar capacity.

Combined-cycle and solar photovoltaic are the most economically attractive generating technologies—

Levelized cost of electricity and levelized avoided cost of electricity by technology and region, 2023 online year (Reference case)

2018 dollars per megawatthour



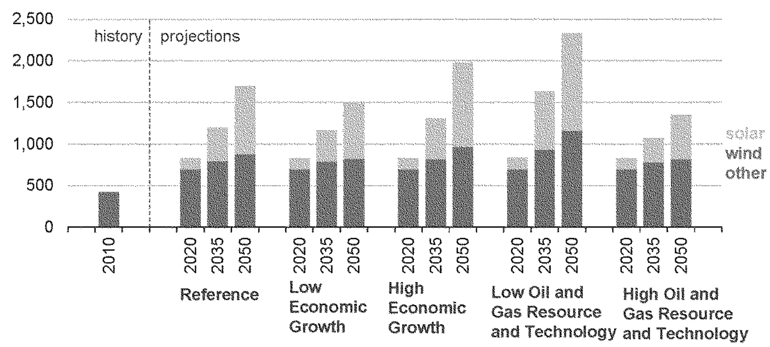
Note: See more information in EIA's LCOE/LACE report on EIA.gov

—when considering the overall cost to build and operate a plant and the value of the plant to the power system

- The levelized cost of electricity (LCOE) indicates the average revenue per unit of generation needed for a generating plant to be economically viable. When compared with the levelized avoided cost of electricity (LACE), or expected average revenue realized by that plant, a rough estimate of economic viability for that generating technology can be determined.
- The solid, colored points on the figure demonstrate that projects tend to be built in regions where value (LACE) exceeds costs (LCOE). Expected revenues from advanced natural gas-fired combined-cycle and solar photovoltaic generating technologies are generally greater than or equal to projected costs across the most electricity market regions in 2023. Correspondingly, these two technologies show the greatest projected growth through the middle of the next decade.
- The figure indicates a few regions where the value of wind is approaching costs, and these regions see new wind capacity builds, primarily in advance of the phase-out of the production tax credit (PTC), through the early part of the next decade. However, the potential wind sites with the most favorable value-to-cost ratios are largely exploited before the PTC expires, with a several-years lag needed for wind values to recover. Markets for wind rebound faster under conditions with higher natural gas prices or faster growth in electricity demand.

Increases in renewables generation is led by solar and wind—

Renewables electricity generation (all sectors) by case
billion kilowatthours

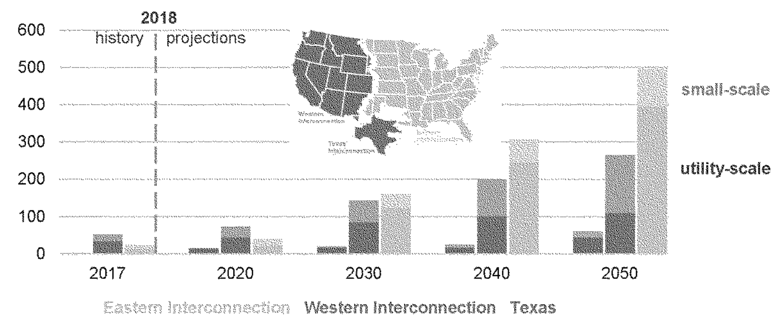


—which grows most quickly in the High Economic Growth and Low Oil and Gas Resource and Technology cases

- Renewables generation increases more than 130% through the end of the projection period in the Reference case, reaching nearly 1,700 billion kilowatthours (BkWh) by 2050.
- Increases in wind and solar generation lead the growth in renewables generation throughout the projection period across all cases, accounting for nearly 900 BkWh (about 90%) of total renewables growth in the Reference case.
- The extended tax credits account for much of the accelerated growth in the near term. Solar photovoltaic (PV) growth continues through the projection period as a result of solar PV costs continuing to decrease.
- In the High Oil and Gas Resource and Technology case, low natural gas prices limit the growth of renewables in favor of natural gas-fired generation. Renewables generation is nearly 350 BkWh lower than in the Reference case in 2050, but this increase is still more than 60% higher than 2018 levels.
- In the Low Economic Growth case, electricity demand is lower than in the Reference case. Because renewables are a marginal source of new capacity additions, this lower level of demand results in nearly 200 BkWh less renewables generation by 2050 compared with the Reference case.

Solar generation grows for both utility- and small-scale sectors—

Solar photovoltaic electricity generation by region (Reference case)
billion kilowatthours

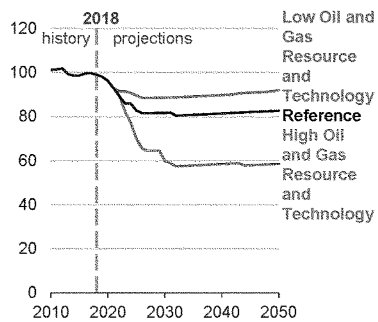


—but at different relative rates across the interconnections

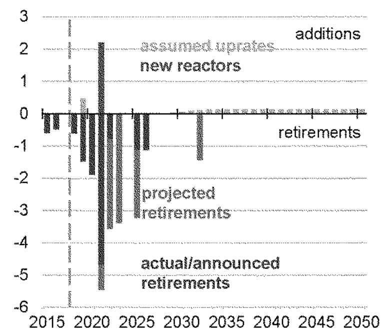
- Electricity generation from solar photovoltaic (PV) in all sectors grows to 15% of total U.S. electricity generation from all technologies by 2050 in the Reference case, and it is composed of more utility-scale systems (66%) than small-scale systems (34%).
- In the Western Interconnection, the growth in solar PV generation comes mostly from small-scale systems, increasing from 34% of the share in 2018 to 57% in 2050.
- Solar PV generation in Texas and in the Eastern Interconnection is produced mostly from utility-scale systems throughout the projection period, averaging 80% for Texas and 76% for the Eastern Interconnection.
- During the projection period, Texas increases its share of U.S. PV generation from 4% in 2018 to 8% in 2050, while the Eastern Interconnection increases its share from 32% to 59%. The share of U.S. PV generation from the Western Interconnection decreases from 64% to 33% during the same period.

Nuclear capacity retirements accelerate with lower natural gas prices—

Nuclear electricity generating capacity
gigawatts



Year-over-year nuclear capacity changes (Reference case)
gigawatts



—as a result of declining revenue in competitive wholesale power markets

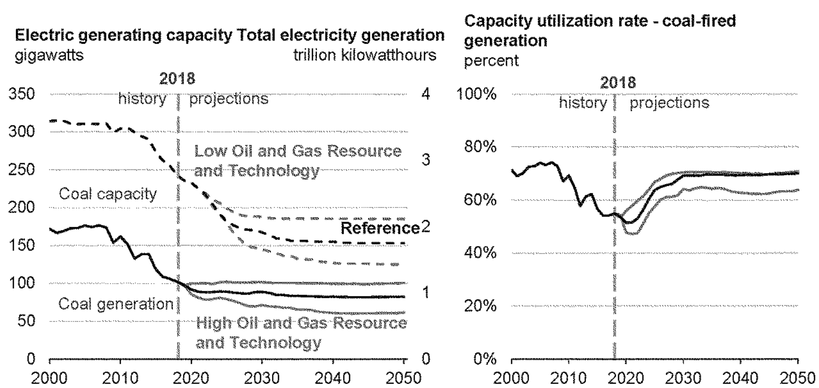
- The Reference case projects a steady decline of 17% in nuclear electric generating capacity from 99 gigawatts (GW) in 2018 to 83 GW in 2050. No new plant additions occur beyond 2021, and existing plants have 2 GW of uprates starting in 2030.

- Projected nuclear retirements are driven by declining revenues resulting from low growth in electricity load and from increasing competition from low-cost natural gas and declining-cost renewables. Smaller, single-reactor nuclear plants with higher average operating costs are most affected, particularly those plants operating in regions with deregulated wholesale power markets and in states without a Zero Emission Credit policy.

- Lower natural gas prices in the High Oil and Gas Resource and Technology case lead to lower wholesale power market revenues for nuclear power plant operators, accelerating an additional 24 GW of nuclear capacity closing by 2050 compared with the Reference case.

- Higher natural gas prices in the Low Oil and Gas Resource and Technology case decrease the financial risks to nuclear power plant operators, resulting in 8 GW fewer retirements and an additional 1 GW of new, unplanned nuclear capacity through 2050 compared with the Reference case.

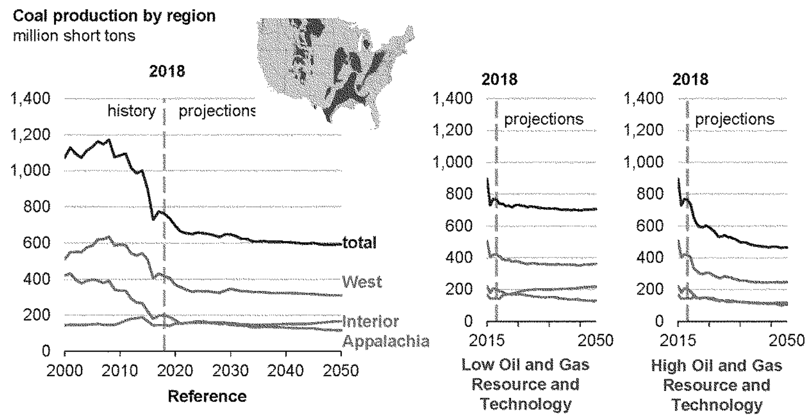
Coal-fired generating capacity retires at a faster pace than generation in the Reference case—



—as capacity factors for coal-fired units improve over time as a result of less efficient units retiring and natural gas prices increasing

- Coal-fired generating capacity decreases by 86 gigawatts (GW) (or 36%) between 2018 and 2035 as a result of competitively priced natural gas and increasing renewables generation before leveling off near 155 GW in the Reference case by 2050.
- Between 2018 and 2035, coal-fired generation decreases by 18% in the Reference case while natural gas prices increase, and the utilization rate of the remaining coal-fired capacity returns to 70%, which is a similar level to that in the early 2000s. In the High Oil and Gas Resource and Technology case, coal-fired generation decreases by 36% while lower natural gas prices limit the utilization rate of the coal fleet to about 64%.
- Higher natural gas prices in the Low Oil and Gas Resource and Technology case slow the pace of coal power plant retirements by approximately 30 GW in 2035 compared with the Reference case, which has 185 GW of coal capacity still in service in 2050. Conversely, lower natural gas prices in the High Oil and Gas Resource and Technology case increase coal-fired power plant retirements by 24 GW in 2035, with 125 GW of remaining coal-fired capacity by 2050.

Coal production decreases through 2035 because of retiring coal-fired electric generating capacity—



—before stabilizing as a result of higher natural gas prices increasing the utilization of coal-fired electric generating capacity

- U.S. coal production in the Reference case continues to decline, from 762 million short tons (MMst) in 2018 to 608 MMst in 2035, before later stabilizing. This decline is in response to coal-fired generating unit retirements and competitive price pressure from natural gas and renewables.

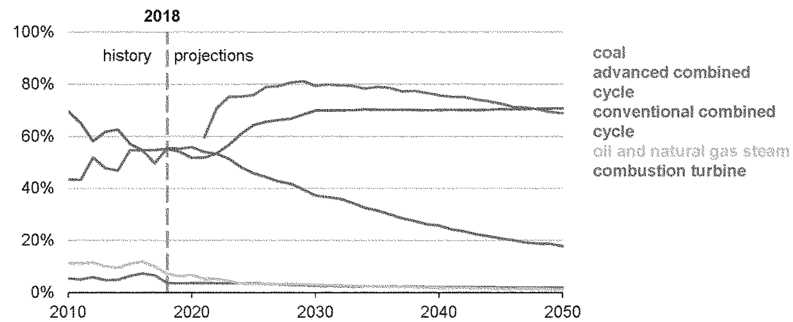
- In the Interior region of the United States, coal production in the Reference case grows by 20 MMst between 2018 and 2050, while production in the Appalachia and the West regions declines by 85 MMst and 106 MMst, respectively.

- In the Low Oil and Gas Resource and Technology case, Interior region coal production in 2050 is 52 MMst (31%) higher than in the Reference case, compared with higher estimates of 13 MMst (11%) in Appalachia and 50 MMst (16%) in the West region.

- In the High Oil and Gas Resource and Technology case, lower natural gas prices result in lower West region coal production in 2050 of 64 MMst (21%) relative to the Reference case, compared with lower regional coal production levels of 12 MMst (11%) in Appalachia and 50 MMst (30%) in the Interior.

Lower operating costs and higher efficiencies result in advanced natural gas-fired combined-cycle capacity factors of 80% by 2030—

Utilization of fossil-fired capacity (Reference case)
percent



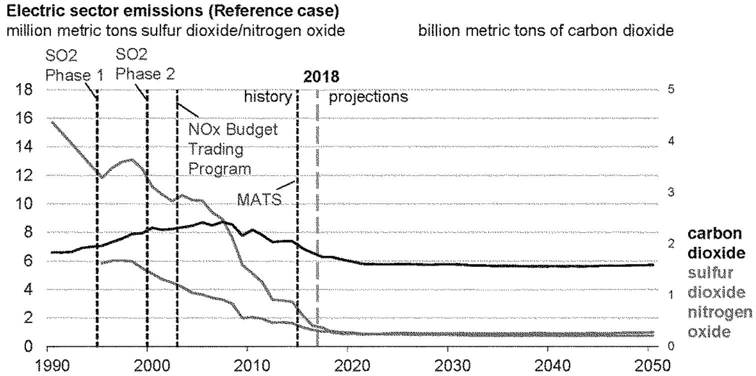
—but then decline over time as natural gas prices increase relative to coal prices

- Lower natural gas prices and reduced capital costs of new natural gas-fired combined-cycle (CC) generating units shift fossil fuel electric generation use during the next decade. Beginning in 2020—the first year of availability—new, advanced CC natural gas-fired units have the highest projected capacity factors of all technologies, averaging 76% between 2025 and 2050. With their lower efficiency, conventional CC units decline in utilization, from 56% in 2020 to 18% by 2050, still remaining higher than combustion turbines but much lower than their designed operating rates.

- New, larger CC designs result in substantial economies of scale for this technology. In line with the April 2018 PJM Report, *PJM Cost of New Entry*, developed for PJM's next generating capacity auction, the cost per unit of installed capacity for the advanced CC design will be 25% to 30% lower compared with older CC units. Through 2050, 235 gigawatts of advanced CC technology is installed.

- The utilization rates of coal and conventional CC will be nearly the same (at about 50%) in the near term. However, the projected installation of advanced CC and the retirement of less efficient coal-fired units contributes to their eventual divergence in 2050, and the remaining coal-fired unit utilization rates recover to 71% while conventional CC utilization rates fall to nearly 20%. Over the long term, coal-fired unit and advanced CC unit utilization rates converge at approximately 70%.

Electric sector emissions in the United States closely track decreasing dependence on coal—



—with carbon dioxide, sulfur dioxide, and nitrogen oxide emissions generally flat going forward

- Any future changes in emissions will be tied to the level of coal-fired generation because EIA's Reference case only incorporates policies that are current laws (including tax credits and air regulations). Coal-fired generation is sensitive to projected natural gas prices.

- Changes in air emissions from power plants in recent years have generally followed the compliance requirements and deadlines specified under the Clean Air Act Amendments of 1990 (CAAA 1990). For sulfur dioxide (SO2), these include the phased implementation of the acid rain cap-and-trade program (Title IV) with deadlines for Phase I and II in 1995 and 2000. For nitrogen oxides (NOx), the key deadline was in 2003, when the Environmental Protection Agency expanded the NOx Budget Trading Program (Title I) to include most states east of the Mississippi. For air toxics (Title III), the initial compliance deadline for the Mercury and Air Toxics Standards (MATS) arrived in April 2015. Finally, emissions of carbon dioxide (CO2) have followed evolving state standards for renewable portfolios or regional caps on CO2.

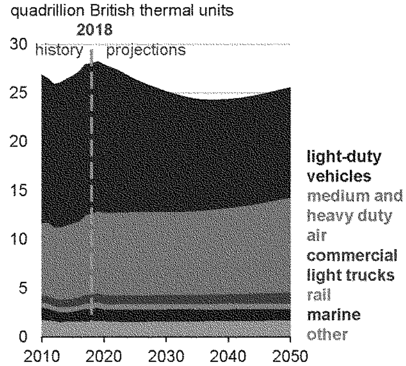
- Once the CAAA 1990 programs are implemented, and in the absence of additional federal regulations on CO2, the level of emissions remains relatively unchanged in the Reference case from 2018 to 2050, despite a 30% increase in generation during the projection period.

Transportation

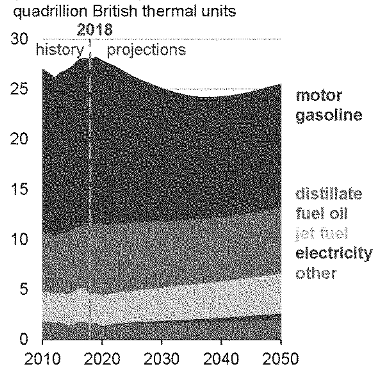
Transportation energy consumption peaks in 2019 in the Reference case because rising fuel efficiency more than offsets the effects of increases in total travel and freight movements, but this trend reverses toward the end of the projection period.

Transportation energy consumption declines between 2019 and 2037 in the Reference case—

Transportation sector consumption (by type) (Reference case)
quadrillion British thermal units



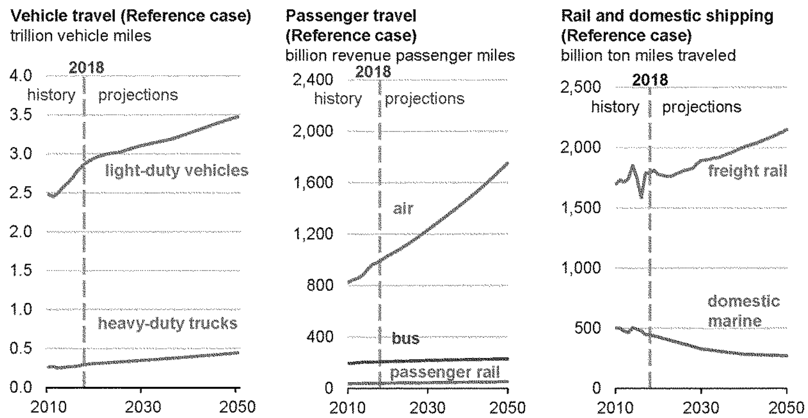
Transportation sector consumption (by fuel) (Reference case)
quadrillion British thermal units



—because increases in fuel economy more than offset growth in vehicle miles traveled

- Increases in fuel economy standards temper growth in U.S. motor gasoline consumption, which decreases by 26% between 2018 and 2050.
- Increases in fuel economy standards result in heavy-duty vehicle energy consumption and related diesel use remaining at approximately the same level in 2050 as in 2018, despite rising economic activity that increases the demand of freight truck travel.
- Excluding electricity (which starts from a comparatively low base), jet fuel consumption grows more than any other transportation fuel during the projection period, rising 35% from 2018 to 2050. This growth arises from increases in air transportation outpacing increases in aircraft fuel efficiency.
- Motor gasoline and distillate fuel oil's combined share of total transportation energy consumption decreases from 84% in 2018 to 74% in 2050 as the use of alternative fuels increases.
- Continued growth of on-road travel increases energy use later in the projection period because current fuel economy and greenhouse gas standards require no additional efficiency increases for new light-duty vehicles after 2025 and for new heavy-duty vehicles after 2027.

Passenger travel increases across all transportation modes in the Reference case through 2050—



—and freight movement increases across all categories except domestic marine

- Light-duty vehicle miles traveled increase by 20% in the Reference case, growing from 2.9 trillion miles in 2018 to 3.5 trillion miles in 2050 as a result of rising incomes and growing population.

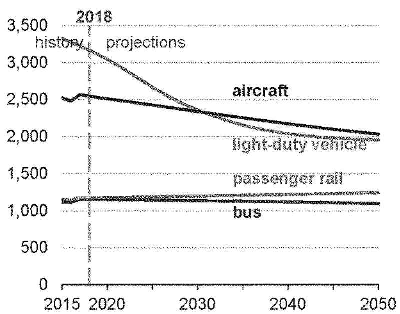
- Truck vehicle miles traveled, the dominant mode of freight movement in the United States, grows by 52%, from 397 billion miles in 2018 to 601 billion miles in 2050 as a result of increased economic activity. Freight rail ton-miles grow by 20% during the same period, led primarily by rising industrial output. However, U.S. coal shipments, which are primarily via rail, decline slightly.

- Air travel grows 77% from 990 billion revenue passenger miles to 1,753 billion revenue passenger miles between 2018 and 2050 in the Reference case because of increased demand for global connectivity and rising personal incomes. Bus and passenger rail travel increase 11% and 31%, respectively.

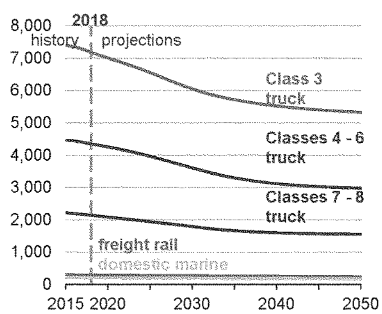
- Domestic marine shipments decline modestly during the projection period, continuing a historical trend related to logistical and economic competition with other freight modes.

Energy intensity decreases across most transportation modes in the Reference case—

Passenger mode energy intensity (Reference case)
British thermal unit per passenger-mile



Freight mode energy intensity (Reference case)
British thermal unit per ton-mile



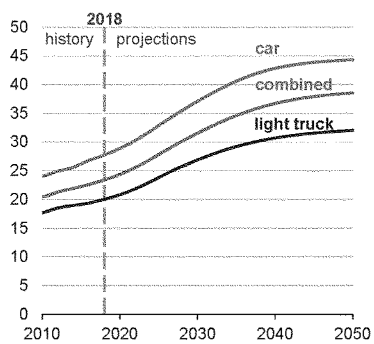
Note: Energy intensity is the energy required for a travel metric. In the graphs above, energy intensity is calculated for passenger modes in British thermal unit (Btu) per passenger-mile (energy to move a passenger one mile) and for freight modes in Btu per ton-mile (energy to move a ton of freight one mile).

—because of policy, economic factors, and technology

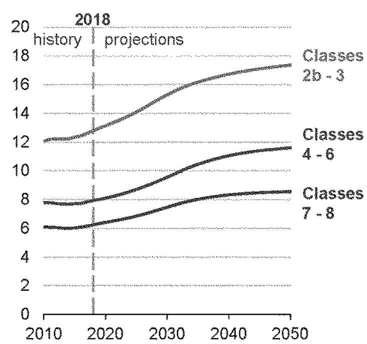
- Energy use per passenger-mile of travel in light-duty vehicles declines nearly 40% between 2018 and 2050 as newer, more fuel-efficient vehicles enter the market, including both more efficient conventional gasoline vehicles and highly efficient alternatives such as battery electric vehicles. Light-duty vehicle energy efficiencies are affected by current federal fuel economy and greenhouse gas emission standards.
- Energy use per passenger-mile of travel in aircraft decreases because of the economically driven adoption of energy-efficient technology and practices. Energy use per passenger-mile of travel on passenger rail and buses, already relatively energy-efficient modes of travel per passenger-mile, remains relatively constant.
- Energy use per ton-mile of travel by freight modes decreases, led by increases in the fuel economy of heavy-duty trucks across all weight classes as the second phase of heavy-duty vehicle efficiency and greenhouse gas standards takes full effect in 2027.
- Gains in energy efficiency offset increases in travel for passenger and freight modes. These efficiency gains decrease energy use by light-duty vehicles and freight trucks later in the projection and temper the rise in energy use by other transportation modes.

Fuel economy of all on-road vehicles increases in the Reference case—

Light-duty fuel economy (Reference case)
miles per gallon (all vehicles)



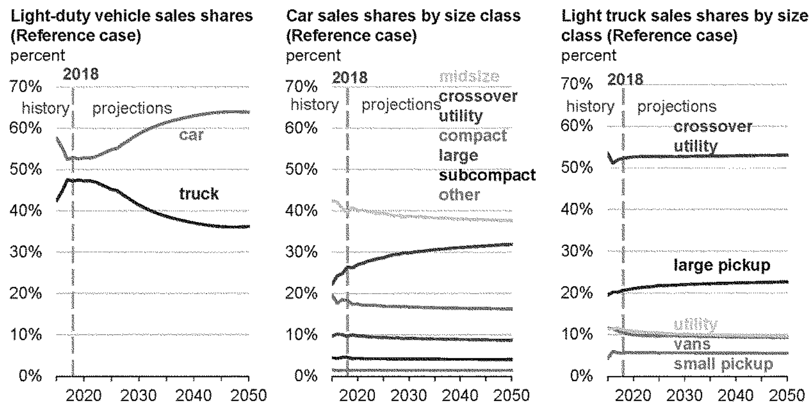
Heavy-duty fuel economy (Reference case)
miles per gallon (all vehicles)



—across all vehicle types throughout the projection period

- The fuel economy of light-duty vehicles in use from 2018 to 2050 increases by 60% for cars and by 60% for light trucks in the Reference case. Across all light-duty vehicles, fuel efficiency improves by 65% from 2018 to 2050 as newer, more fuel-efficient vehicles enter the market, including a higher share of cars, which are more efficient than light trucks.
- Fuel economy of the heavy-duty vehicles in use improves across all weight classes as the second phase of heavy-duty vehicle efficiency and greenhouse gas standards takes full effect in 2027.
- Gains in fuel economy temper heavy-duty vehicle energy consumption growth and decrease light-duty vehicle energy consumption. After 2040, increasing vehicle travel outweighs fuel economy improvements, leading to increases in fuel demand.

Sales of more fuel-efficient cars and light-truck crossover utility vehicles increase—



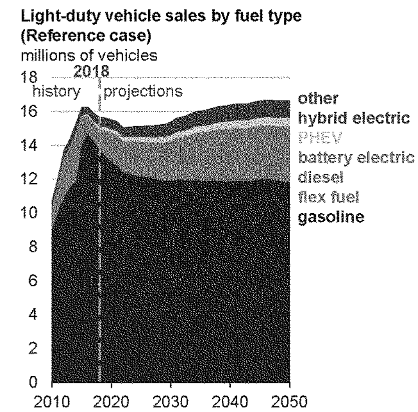
—but traditional vehicle types maintain significant market share through 2050

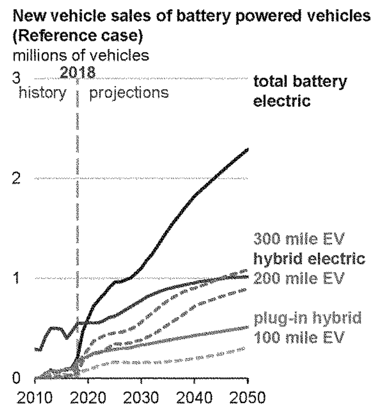
- Passenger cars gain light-duty vehicle market share relative to light-duty trucks because they have higher fuel efficiency in periods when motor gasoline prices increase and because crossover utility vehicles, often classified as passenger cars, may replace lower fuel economy light-truck classified utility vehicles as a result of increasing availability and popularity.

- Light trucks lose light-duty vehicle market share and see a shift away from traditional vans and utility vehicles toward crossover utility vehicles that are classified as higher fuel economy light trucks.

- Combined car and light truck classified crossover utility vehicles reach 40% of new light-duty vehicle sales in 2050, largely taking away sales from traditional compact, midsize, and large cars and from truck-based sport utility vehicles.

Alternative and electric vehicles gain market share in the Reference case—





—but gasoline vehicles remain the dominant vehicle type through 2050

- The combined share of sales attributable to gasoline and flex-fuel vehicles (which use gasoline blended with up to 85% ethanol) declines from 93% in 2018 to 75% in 2050 because of the growth in battery electric vehicle (BEV), plug-in hybrid electric vehicle (PHEV), and hybrid electric vehicle sales.

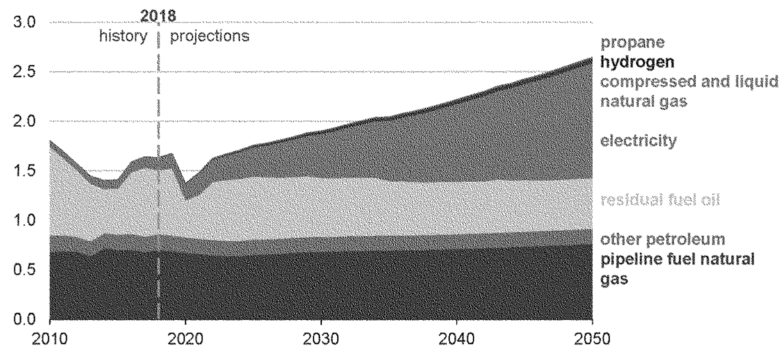
- California's Zero-Emission Vehicle regulation, which nine additional states have adopted, requires a minimum percentage of vehicle sales of BEV and PHEV. In 2025, the year the regulation and new federal fuel economy standards go into full effect, projected sales of BEV and PHEV reach 1.3 million, or about 8% of projected total vehicle sales in the Reference case.

- Sales of the longer ranged 200- and 300-mile BEVs grow during the entire projection period, tempering sales of the shorter-range 100-mile BEV and PHEV.

- New vehicles of all fuel types show significant improvements in fuel economy because of compliance with increasing fuel economy standards. New vehicle fuel economy rises by 43% from 2018 to 2050.

Consumption of transportation fuels grows considerably in the Reference case between 2018 and 2050—

Transportation sector consumption of minor petroleum and alternative fuels (Reference case)
quadrillion British thermal units



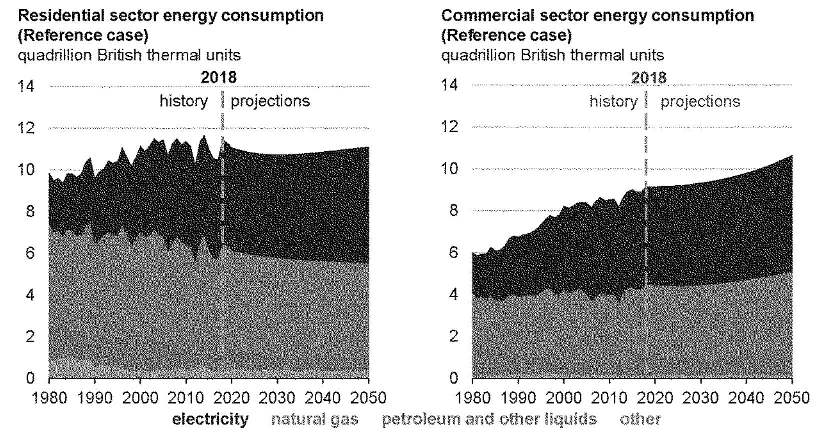
—because of increased use of electricity and natural gas

- Electricity use in the transportation sector increases sharply after 2020 in the Reference case because of the projected rise in the sale of new battery electric and plug-in hybrid-electric light-duty vehicles.
- Natural gas consumption increases during the entire projection period because of growing use in heavy-duty vehicles and freight rail.
- In the later years of the projection period, liquefied natural gas is used in the maritime industry as an alternative to burning high-sulfur residual fuel oil to meet the new standards set for marine fuels under the International Convention for the Prevention of Pollution from Ships (MARPOL convention).

Buildings

Delivered energy consumption and on-site generation in the residential and commercial buildings sectors are expected to grow through 2050 in the Reference case. At the same time, increasing demand for electricity and natural gas is partially offset by advances in energy efficiency.

Residential and commercial energy consumption grows slowly in the Reference case—



—accounting for changes to energy efficiency standards and technological advances

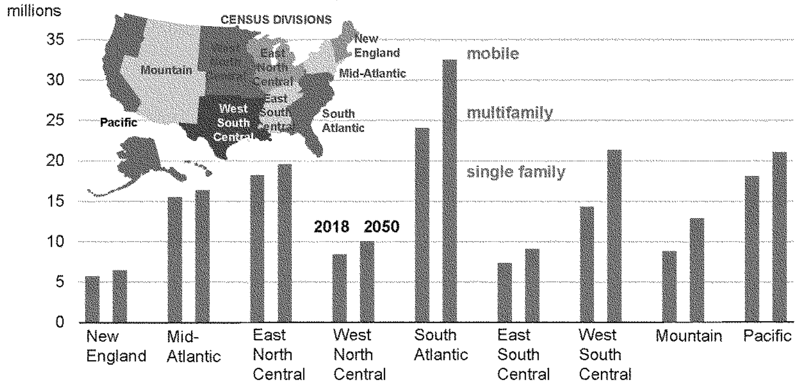
- In the AEO2019 Reference case, delivered energy consumption for buildings increases by 0.2% per year from 2018 to 2050, as growth outpaces energy efficiency improvements later in the projection period. Residential delivered energy consumption decreases by 0.1% per year to 2050 and commercial delivered energy consumption rises by 0.5% per year. Together, residential and commercial buildings account for 27% of U.S. total delivered energy consumption during the projection period.

- Electricity consumption grows in both sectors as a result of increased demand for electricity-using appliances, devices, and equipment. During the projection period, consumption of purchased electricity increases by 0.4% and 0.5% per year in the residential and commercial sectors, respectively.

- Natural gas consumption by commercial buildings grows by 0.5% per year from 2018 to 2050, led by increased natural gas-driven distributed generation (combined heat and power). Consumption of natural gas in the residential sector falls by 0.3% per year as its use for space heating continues to decline.

Residential housing stocks continue to grow—

Residential housing units (Reference case)
millions

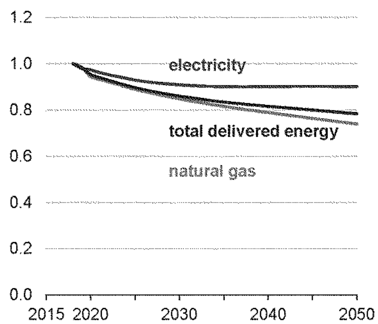


—especially in warmer regions with higher space cooling demand

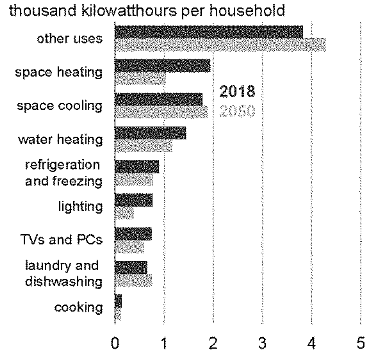
- The number of U.S. households increases by an average of 0.7% per year from 2018 through 2050, with single-family homes growing most quickly at 0.8% per year. Mobile home stocks decrease by 0.8% per year and are the only category not expected to grow.
- Cooling-dominated West South Central, South Atlantic, and East South Central census divisions all experience average annual housing stock growth that exceeds the national average.
- The size of housing units also continue to grow; the national average floorspace per home increases 0.3% per year from 1,779 square feet in 2018 to 1,978 square feet in 2050.

Residential energy intensity decreases in the Reference case—

Residential delivered energy intensity index (Reference case)
2018=1.0



Residential purchased electricity intensity (Reference case)
thousand kilowatthours per household



—although changes in electricity consumption vary by end use

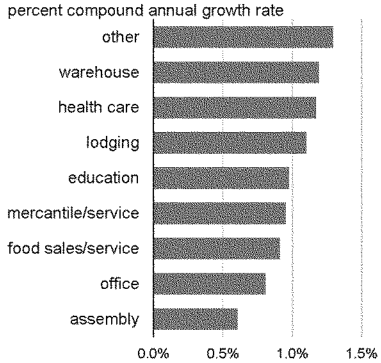
- Total delivered residential energy intensity, defined as annual delivered energy use per household, decreases by 22% from 2018 to 2050 as the number of households grows faster than energy use. The main factors contributing to this decline include gains in appliance efficiency, on-site electricity generation (e.g., solar photovoltaic), utility energy efficiency rebates, increasing residential natural gas prices, and lower space heating demand based on historical trends and a continued population shift to warmer regions.

- Lighting electricity consumption per household declines faster than other electric end uses as a result of compliance with minimum performance requirements of the Energy Independence and Security Act of 2007. The federal standards effectively eliminate low-efficacy incandescent lamps, replacing them with more energy-efficient light-emitting diodes (LEDs) and compact fluorescent lamps (CFLs) by 2020. Energy efficiency incentives also accelerate LED and CFL penetration before 2020. In 2050, purchased electricity intensity for lighting is 51% lower than in 2018.

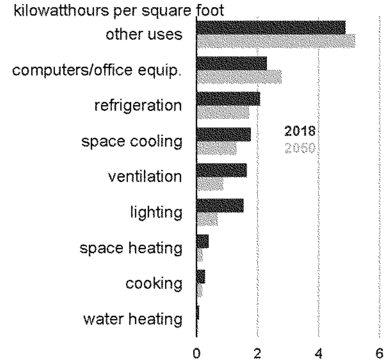
- As near-term appliance standards result in efficiency gains beyond those caused by market forces and technological change, electricity intensity declines the most quickly before 2030.

Commercial energy consumption growth is limited because of increased appliance and lighting efficiencies—

Commercial floorspace growth (Reference case)
percent compound annual growth rate



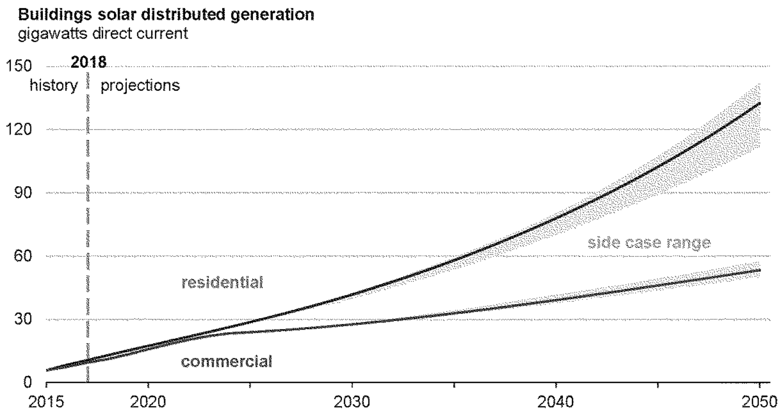
Purchased electricity consumption intensity (Reference case)
kilowatthours per square foot



—but growing floorspace and expanding information technology needs drive an overall increase in electricity consumption

- Commercial floorspace grows by an average 1% per year in the Reference case through the projection period, reflecting rising economic output. Some of the fastest-growing building types, including health care and lodging, are also among the most energy-intensive.
- Commercial electricity intensity, defined as electricity consumption per square foot of commercial floorspace, declines at an average 0.4% per year from 2018 to 2050. Lighting accounts for the steepest intensity decline among the major end uses, as falling costs and energy efficiency incentives lead efficient light-emitting diodes to displace linear fluorescent lighting as the dominant commercial lighting technology by 2030.
- Improved appliance efficiency and a population shift to warmer regions of the United States cause commercial electricity consumption for space heating, water heating, and ventilation to decline by 29% from 2018 to 2050. This population shift causes space cooling intensity to decrease less rapidly, and commercial space cooling electricity consumption remains flat during the projection period.
- Although the United States has no federal building energy code, state- and local-level building codes also reduce energy used for heating and cooling in commercial buildings.

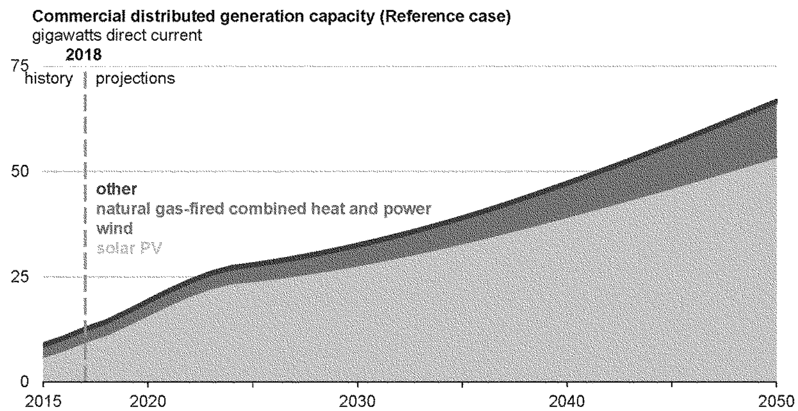
Rooftop solar PV adoption grows between 2018 and 2050—



—with residential growth outpacing commercial growth in later years

- Residential solar photovoltaic (PV) capacity increases by an average of 8% annually from 2018 through 2050 in the Reference case compared with the commercial sector's 5% per year average growth.
- PV costs decline most rapidly before 2030, despite the phasedown in the federal business Investment Tax Credit (ITC) from 30% in 2019 to 10% in 2022 and the four-year Section 201 tariff levied on PV cells and modules in 2018. Declining installation costs and stable retail electricity rates drive steady commercial PV adoption.
- Rising incomes, declining system costs, and social influences accelerate the adoption of residential PV. Adoption rates in the High and Low Economic Growth cases vary the most from the Reference case.
- Aside from installed PV costs, PV growth is sensitive to electricity prices, which vary by up to 11% in 2050 in the High and Low Oil and Gas Resource Technology cases relative to the Reference case for both the residential and commercial sectors.

Combined heat and power and other non-solar sources account for less than one-quarter of commercial on-site capacity in 2018—



—but they grow by more than 4% per year, driven by equipment cost declines and near-term tax credits

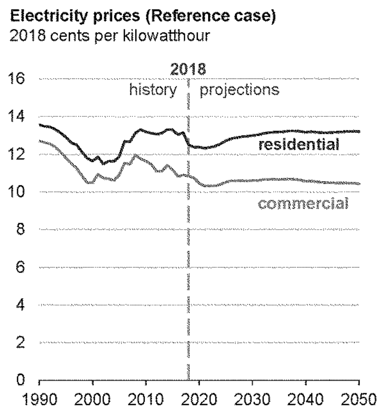
- Non-photovoltaic (PV) technologies such as combined heat and power (CHP) and distributed wind account for 24% of commercial distributed generation capacity in 2018. Although the growth is much slower than for commercial PV, these technologies grow from 3.5 gigawatts of capacity in 2018 to 13.6 gigawatts of capacity by 2050 in the Reference case.

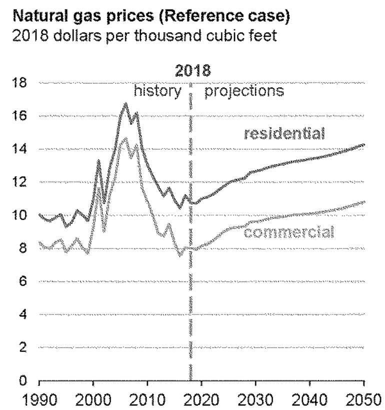
- Apart from PV, natural gas-fired CHP (i.e., conventional turbine, microturbine, reciprocating engine, and fuel cell) capacity expands the most quickly at an average of 5% per year. Its growth is a result of low equipment costs throughout the projection period.

- The installed cost of commercial wind equipment falls by 30% between 2018 and 2050, resulting in an average growth in capacity of 4% per year during this period.

- The 2018 Bipartisan Budget Act extends the Investment Tax Credit provisions for qualifying CHP and small wind equipment (defined as wind turbines with a capacity less than 100 kW) beginning construction before January 1, 2022. These tax credits drive further growth in non-PV distributed generation in the short term.

Residential and commercial electricity prices remain flat during the projection period—





—while natural gas prices rise, moderating natural gas consumption

- Electricity prices fall in the near term, primarily because utilities pass along savings from lower taxes under the Tax Cuts and Jobs Act of 2017, but also because they replace more costly power plants with new plants that are less expensive to construct and operate. Lower prices encourage more consumption in the near term in both sectors, although near-term efficiency standards and population shifts to warmer areas of the country moderate this trend.

- Natural gas prices in both the residential and commercial sectors increase steadily by an average of 0.9% per year during the projection period. Increasing natural gas prices decrease consumption in the residential sector and moderate consumption growth in the commercial sector.

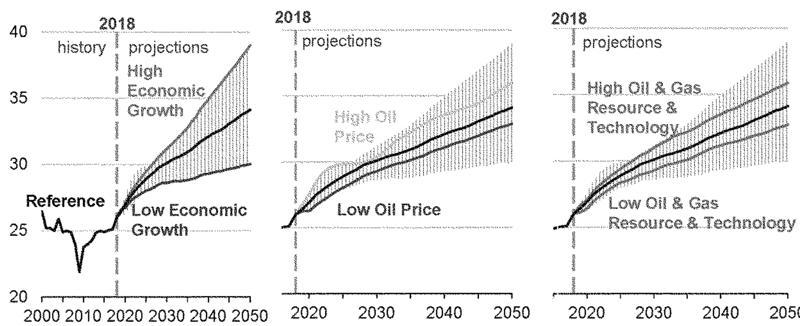
- Despite increasing natural gas prices, commercial natural gas consumption still grows an average of 0.5% per year during the projection period. This growth is driven in part by increased distributed generation and combined heat and power. Commercial natural gas-driven generating capacity in 2050 grows to nearly five times its 2018 level.

Industrial

Energy consumption in the industrial sector increases between 2018 and 2050 across all cases. Increases in industrial energy use from increasing shipments are partially offset by efficiency gains. Consumption of all energy sources except coal increases, while coal consumption declines.

Consumption of delivered industrial energy grows in all cases—

Industrial delivered energy consumption
quadrillion British thermal units



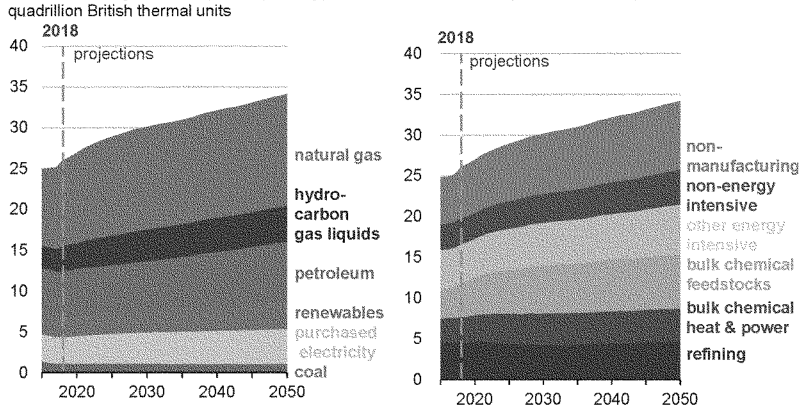
Note: The hatched area on each graph denotes the range between minimum and maximum values among all six side cases for that year.

—driven by economic growth and affected by low prices and resource availability

- U.S. industrial delivered energy consumption in the Reference case grows 31% from 26 quadrillion British thermal units (Btu) to 34 quadrillion Btu between 2018 and 2050.
- By the mid-2020s, industrial energy consumption is highest in the High Economic Growth case, reaching 39 quadrillion Btu in 2050, a 50% increase from 2018. With a faster growing economy, more industrial output such as in food and fabricated metal products increases industrial energy use.
- Initially, industrial energy consumption in the High Oil Price case exceeds consumption in the other cases as a result of higher demand for U.S. products and increased energy use for natural gas liquefaction. After this period, consumption expenditures and investment decline because higher crude oil prices effectively lower income, as well as output growth and energy consumption growth.
- Energy consumption in the High Oil and Gas Resource Technology case is higher than in the Reference case as a result of increased crude oil and natural gas resources and improved extraction technologies that increase energy demand in the mining industry.

Industrial sector energy consumption increases at a similar rate for most fuels in the Reference case—

Industrial energy consumption by energy source and subsector (Reference case)
quadrillion British thermal units

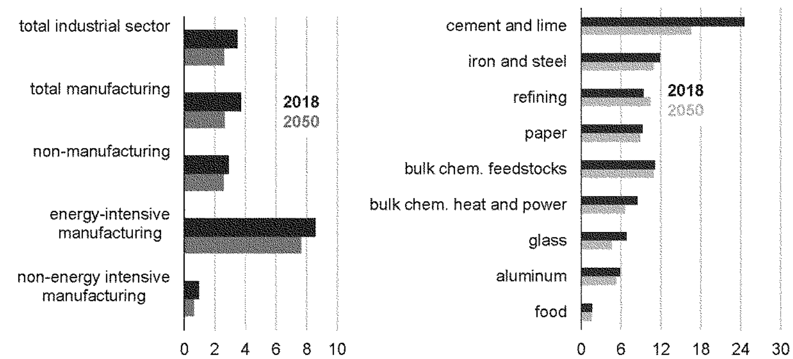


—and bulk chemicals and nonmanufacturing are the fastest-growing industries

- Total industrial delivered energy consumption grows 0.9% per year on average from 2018 to 2050 in the Reference case. All fuels, except coal, have a similar growth rate, declining slightly during the projection period. Industrial energy consumption grows more slowly than economic growth because of increasing energy efficiency.
- Natural gas and petroleum (including hydrocarbon gas liquids) account for most delivered industrial energy consumption. Hydrocarbon gas liquids such as ethane are used as feedstock for bulk chemical production and are a major source of growth in the industrial use of petroleum.
- Energy consumption in the bulk chemicals industry, including both heat and power and feedstocks, accounts for about 30% of total industrial energy consumption and grows at 1.2% per year.
- Nonmanufacturing industries' energy consumption grows 1.0% per year from 2018 to 2050. While energy use to liquefy natural gas for export grows at 5.0% per year, construction energy consumption grows relatively quickly at 1.2% per year. Agriculture energy consumption growth is much slower because of relatively slow distillate growth. Distillate is used for off-road vehicles.

In the Reference case, energy intensities decline in almost all energy-intensive industries—

Energy intensity by subsector and energy intensive manufacturing industry (Reference case)
trillion British thermal units per billion 2009 dollar shipments



—reflecting efficiency gains in existing capacity and implementation of new, more energy-efficient technologies

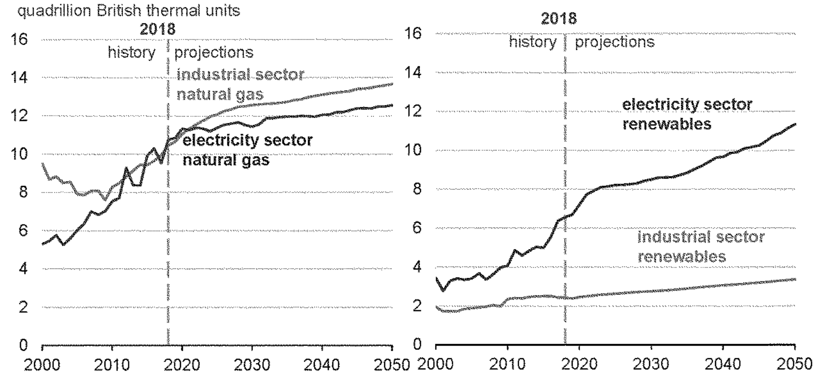
- Energy intensity in the industrial sector (energy consumption per dollar of output) declines by 0.9% per year on average from 2018 to 2050 in the Reference case. In manufacturing, energy intensity declines as a result of increased energy efficiency of new capital equipment and a shift in the share of production away from energy-intensive industries toward non-energy intensive industries, such as metal-based durables.

- Although the energy-intensive manufacturing industries' energy intensity declines by a little more than 10%, the non-energy-intensive manufacturing industries see a decline three times faster between 2018 and 2050 because these non-energy intensive manufacturing industries use less heat. Cement and lime intensity declines the most during the projection period, because, to some extent, the dry cement manufacturing process replaces the more energy-intensive wet process during the projection period.

- For some industries, large amounts of combined heat and power generation (CHP) may mask some efficiency gains. CHP generation losses are included in industry energy consumption, but purchased electricity generation losses are included in the electricity sector.

In the Reference case, industrial natural gas use exceeds electricity sector natural gas use—

Natural gas and renewables consumption in the industrial and electric power sectors (Reference case)



—while industrial renewables consumption declines relative to renewables consumption in the electricity sector

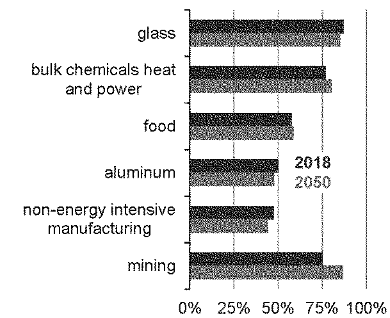
- After consuming about the same amount of natural gas as the electricity sector through the 2010s, the industrial sector uses relatively more natural gas after the mid-2020s. Increased natural gas use for heat and power, as lease and plant fuel, and increased energy use for liquefaction lead to higher growth in the industrial sector than in the electricity sector.

- Growth in natural gas-fired electricity slows relative to historical growth rates as a result of the widespread adoption of natural gas-fired generation in previous years. Natural gas replaced coal as the dominant generation fuel by 2015. In addition, electricity from renewables will increase more rapidly than in the past. Both factors slow the future growth of natural-gas fired generation relative to recent years.

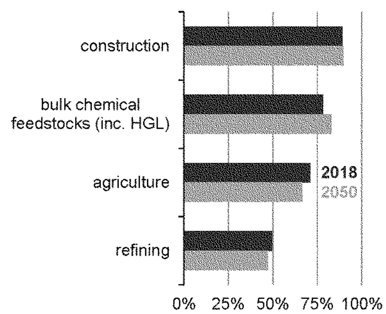
- Renewables consumption, including municipal solid waste, in the industrial sector and electricity sector diverges between 2018 and 2050. Renewables consumption grows nearly twice as fast in the electricity sector (1.7% per year) than in the industrial sector (1.0% per year) during the projection period. In a few industries—notably food, paper, and wood—renewables already account for a substantial share of total consumption. Other industries, such as bulk chemicals and steel, cannot economically consume renewables.

Several industries continue to use natural gas for a large share of their energy needs in the Reference case—

Natural gas share of energy used for high relative natural gas consumers (Reference case)
percent of total



Petroleum share of energy used for high relative petroleum consumers (Reference case)
percent of total

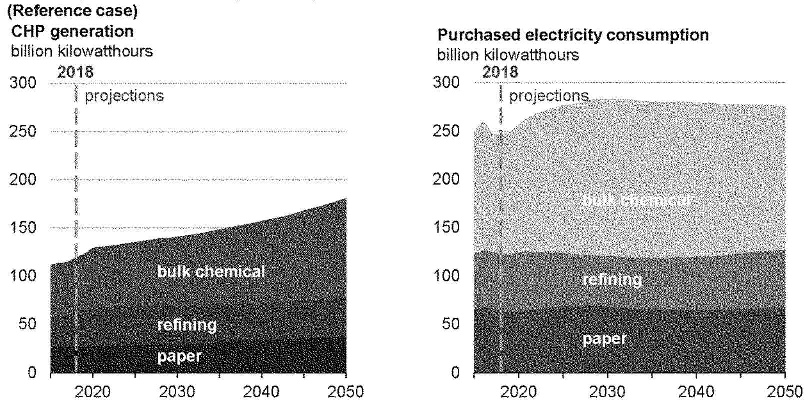


—while fewer industries rely more on petroleum

- In the Reference case, four energy-intensive manufacturing industries, the entire non-energy intensive manufacturing subsector, and the mining industry used natural gas for more than 40% of their fuel needs. Combined, these industries consumed 7.2 quadrillion British thermal units (Btu) in 2018, or about 70% of total industrial natural gas consumption. These industries consume 10.0 quadrillion Btu of natural gas in 2050.
- These industries use natural gas in different ways. The glass industry uses natural gas for high temperature furnaces. Food and bulk chemicals heat and power use natural gas for heating, steam production, and power generation. The aluminum industry uses natural gas in electric arc furnaces. Non-energy intensive industries use natural gas for heating and cooling buildings. Mining uses natural gas for lease and plant fuel and for a new use—energy to liquefy natural gas for export.
- Four industries use petroleum for more than 40% of their energy needs. Combined, these industries consume 8.8 quadrillion Btu of petroleum in 2018, or about 90% of total industrial consumption, and consumption grows to 11.8 quadrillion Btu in 2050. Agriculture and construction use petroleum mostly for off-road vehicles, while refining uses petroleum, such as still gas, for heat and power. More than 75% of total bulk chemical feedstocks are petroleum products (including hydrocarbon gas liquids).

Self-generation from combined heat and power (CHP), especially for bulk chemicals, grows—

CHP and purchased electricity consumption for three industries with most installed CHP (Reference case)



—even though electricity purchases for major CHP users remain flat during the projection period in the Reference case

- Electricity generation from CHP in bulk chemicals, refining, and paper—industries with the most CHP—grows 1.3% per year, from 120 billion kilowatthours (kWh) in 2018 to 181 billion kWh in 2050.
- Bulk chemicals, refining, and paper use the most CHP because they are large industries with high heating needs, and steam is available to use for generation. In 2018, the ratio of CHP generation to purchased electricity is approximately 50% in these industries. By 2050, this ratio climbs to 65%, largely as a result of CHP growth in the bulk chemicals industry.
- While the bulk chemicals industry CHP generation is 90% natural gas-fired or more, the refining and paper industries use sizeable quantities of other fuels. Most paper industry CHP generation is fired by renewables such as black liquor (a byproduct of the pulping process). The refinery industry also uses still gas, a byproduct fuel, for CHP generation. About two-thirds of refining generation is natural gas-fired.
- Of the remaining industries, food and steel have substantial, but much less, CHP than bulk chemicals, paper, and refining. Most other industries have little or no CHP.

References

Commonly used acronyms and abbreviations in this report

AEO = Annual Energy Outlook
b = barrel(s)
BEV = battery-electric vehicle
b/d = barrels per day
bkWh = billion kilowatthours
Btu = British thermal unit(s)
CFL = compact fluorescent lamp
CHP = combined heat and power
CO2 = carbon dioxide
EIA = U.S. Energy Information Administration
gal = gallon(s)
GDP = gross domestic product
GW = gigawatt(s)
HGL = hydrocarbon gas liquid(s)
ITC = Investment Tax Credit
kWh = kilowatthour(s)
LED = light-emitting diode
LNG = liquefied natural gas
MARPOL = *marine pollution*, the International Convention for the Prevention of Pollution from Ships
MMBtu = million British thermal units
MMst = million short tons
NEMS = National Energy Modeling System
NGPL = natural gas plant liquids
PHEV = plug-in hybrid electric vehicle
PTC = production tax credit
PV = photovoltaic
Tcf = trillion cubic feet
ZEV = zero-emission vehicle

Graph sources

In general:

- Projected values are sourced from:
  - *Short-Term Energy Outlook*, October 2018
  - Projections: EIA, AEO2019 National Energy Modeling System (runs: ref2019.d111618a, highprice.d111618a, lowprice.d111618a, highmacro.d111618a, lowmacro.d111618a, highrt.d111618a, lowrt.d111618a)
- Historical data are sourced from:
  - *Monthly Energy Review* (and supporting databases), September 2018
  - IHS Markit, Macroeconomic, Industry, and Employment models, May 2018

The history in some graphs are based off of other sources. For source information for specific graphs published in this document, contact annualenergyoutlook@eia.gov.

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AEO Analysis and Forecasting Experts
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For more information

U.S. Energy Information Administration homepage | www.eia.gov

Short-Term Energy Outlook | www.eia.gov/steo

Annual Energy Outlook | www.eia.gov/aeo

International Energy Outlook | www.eia.gov/ieo

Monthly Energy Review | www.eia.gov/mer

Today in Energy | www.eia.gov/todayinenergy

WESTERN GOVERNORS' ASSOCIATION

DAVID IGE
GOVERNOR OF HAWAII
CHAIR

DOUG BURGUM
GOVERNOR OF NORTH DAKOTA
VICE CHAIR

JAMES D. OGSBURY
EXECUTIVE DIRECTOR

February 4, 2019

The Honorable Lisa Murkowski
Chairman
Committee on Energy and Natural Resources
U.S. Senate
304 Dirksen Senate Building
Washington, D.C. 20510

The Honorable Joe Manchin
Ranking Member
Committee on Energy and Natural Resources
U.S. Senate
304 Dirksen Senate Building
Washington, D.C. 20510

Dear Chairman Murkowski and Ranking Member Manchin:

Western Governors appreciate the Committee's examination of energy and minerals markets in its hearing tomorrow. To inform the Committee's consideration of this subject, I request that the Committee include the following attachments in the permanent record of the hearing:

- WGA Policy Resolution 2018-09, *National Minerals Policy*; and
- WGA Policy Resolution 2018-04, *Energy in the West*, and the Governors' Energy Vision for the West.

Thank you for your consideration of this request.

Respectfully,

Jim Ogsbury

James D. Ogsbury
Executive Director

Attachments

WESTERN GOVERNORS' ASSOCIATION

Policy Resolution 2018-09

National Minerals Policy

A. BACKGROUND

1. Federal lands account for as much as 86 percent of the land area in certain western states. These same states account for 75 percent of our nation's metals production. Few countries are as blessed with the abundance of minerals and metals as is the United States.

2. The Mining and Minerals Policy Act of 1970 formally recognized the importance of mining and domestic minerals production as a policy of the United States, including "the development of economically sound and stable domestic mining, minerals, metal and mineral reclamation industries," "the orderly and economic development of mineral resources ... to help assure satisfaction of industrial, security and environmental needs," "mining, mineral and metallurgical research," "... including the use and recycling of scrap to promote the wise and efficient use of our natural and reclaimable resources; the study and development of methods for the disposal, control and reclamation of mineral waste products, and the reclamation of mined land, so as to lessen adverse impacts of mineral extraction."

3. Access to domestic minerals is increasingly important to decrease our reliance on foreign sources. Twenty-five years ago, the United States was dependent on foreign sources for 45 nonfuel mineral materials. The U.S. imported 100 percent of the Nation's requirements for 8 of these and imported more than 50 percent of the Nation's needs for another 19. By 2014, U.S. import dependence for nonfuel mineral materials had risen significantly from 45 to 65 commodities. The United States imported 100 percent of the Nation's requirements for 19 of these, imported more than 50 percent of the Nation's needs for another 24.

4. A major factor contributing to the U.S. reliance on foreign sources of minerals is a duplicative and inefficient mine permitting system that discourages development of domestic resources. While processes have improved, it can take seven to 10 years in the United States to navigate this cumbersome federal process to bring a mine into production. The same process takes approximately two years in countries that have comparable environmental standards such as Canada and Australia.

5. Ensuring timely access to domestic minerals will strengthen our economy and keep us competitive globally as demand for minerals continues to grow, especially for manufacturing and construction. Our antiquated and duplicative permitting process discourages investment and jeopardizes the growth of downstream industries, related jobs and technological innovation that all depend on a secure and reliable mineral supply chain. Permitting delays also impede the United States' ability to meet growing demand for consumer products from smart phones and hybrid car batteries to renewable energy technologies like wind turbines and solar panels – all of which require minerals and metals in their manufacture.

6. The Mining Law has provided the framework for developing hardrock minerals on the public lands. It has been supplemented by a large body of federal, state, tribal and local

environmental and reclamation laws and regulations (including regulations promulgated by the federal land management agencies) to assure protection of the environment, wildlife and cultural resources during mineral exploration and development and to ensure reclamation of lands after active mining ceases.

The National Academy of Sciences' National Research Council, after a comprehensive review of these laws and regulations at the direction of the Congress, concluded that existing laws and regulations are "complicated but generally effective." It also identified "specific issues or 'gaps' in existing..." regulations intended to protect the environment."

7. Hardrock mining operations on both public and private lands in the western states are subject to Federal environmental laws under both the U.S. Environmental Protection Agency (EPA) and the Army Corps of Engineers. In most states, the Clean Water Act, the Clean Air Act, the Toxic Substances Control Act, the Resource Conservation and Recovery Act, and the Safe Drinking Water Act are administered by state environmental agencies with oversight by the EPA. Hardrock mining operations are also subject to regulatory programs for the protection of plants and wildlife, including the Endangered Species Act, the Migratory Bird Treaty Act, and the Bald Eagle Protection Act.

8. Furthermore, the modern hardrock mining industry is extensively regulated by the federal government on U.S. Bureau of Land Management- and U.S. Forest Service-administered lands. These regulations include review of the mining plan of operations, comprehensive permit, design, operations, closure, reclamation requirements, corrective action and financial assurance requirements, to ensure that the mining operations will not result in unnecessary or undue degradation of public lands.

9. The western states also extensively regulate hardrock mining operations on both private and public lands (state and federal), and uniformly impose permit and stringent design and operating standards, as well as financial assurances to ensure that hardrock mining operations are conducted in a manner that is protective of human health and the environment, and that, at closure, the mined lands are returned to a safe, stable condition for productive post-mining use.

10. Under the federal Mining Law, no royalties are owed to the federal or state governments for hardrock minerals extracted from federal public lands. However, such mining operations, which are most often located in rural areas lacking economic opportunities, can result in significant high-wage employment, royalties from private and state lands, increased state and local tax revenues and development of infrastructure necessary to support communities.

B. GOVERNORS' POLICY STATEMENT

1. Now is the time to build on the 1970 Mining and Minerals Policy Act with legislation and policies that will unlock our mineral potential to ensure access to the metals that are critical to U.S. economic and national security – providing vital base materials for electronics, telecommunications, satellites, aircraft, manufacturing and alternative energy technologies (particularly wind and solar).

2. Western Governors recognize that the minerals mining industry is an important component to both local and national economies. Reliable supplies of minerals and metals play a critical role in meeting our economic and national security needs.

3. WGA commends efforts by the United States Geological Survey and state geological surveys to identify potential, critical minerals deposits for alternative energy technologies and other consumer products vital to modern society.

4. The Congress, in consultation with the states, should develop a National Minerals Policy that truly enables mineral exploration and development in a manner that balances the nation's industrial and security needs with adequate protection of natural resources and the environment. Without reducing environmental or other protections afforded by current laws and regulations, any policy must address the length of the mine permitting process to ensure we can develop and provide the domestic resources that are critical to our national and economic security. Any policy should also take into account the potential long-term effects (including potential environmental effects) of mining operations and should maintain policies and procedures in place to mitigate any long-term effects.

5. A National Minerals Policy should address permitting delays, patenting, maintenance fees, an equitable government revenue mechanism, and the development of a clean-up fund and program for reclaiming abandoned hard rock mines. Relevant stakeholders, including the mining industry, should continue to work with Congress to determine the elements of a royalty system that is workable and fair.

6. New financial assurance requirements imposed upon the hardrock mining industry under CERCLA Section 108(b) would duplicate or supplant existing and proven state financial assurance regulations in this area. This is of particular concern to the western states, because CERCLA is a non-delegable federal program that provides no opportunity for implementation through state environmental agencies. The western states have developed deep experience in mine permitting, regulation, and closure. Federal preemption of state bonding programs will threaten these effective state programs.

7. The U.S. Department of the Interior and the U.S. Department of Agriculture should take an active role, working with western states, in the development of a National Minerals Policy that recognizes the importance of a domestic supply of minerals for our country.

C. GOVERNORS' MANAGEMENT DIRECTIVE

1. The Governors direct the WGA staff, where appropriate, to work with Congressional committees of jurisdiction and the Executive Branch to achieve the objectives of this resolution.

2. Furthermore, the Governors direct WGA staff to develop, as appropriate and timely, detailed annual work plans to advance the policy positions and goals contained in this resolution. Those work plans shall be presented to, and approved by, Western Governors prior to implementation. WGA staff shall keep the Governors informed, on a regular basis, of their progress in implementing approved annual work plans.

Western Governors enact new policy resolutions and amend existing resolutions on a bi-annual basis. Please consult www.westgov.org/policies for the most current copy of a resolution and a list of all current WGA policy resolutions.

Western Governors' Association Policy Resolution 2018-04

Energy in the West

A. BACKGROUND

1. Energy policy and the development of sustainable energy resources are major priorities for every Western Governor.

2. Western Governors recognize that approaches to energy use and development vary among our states, territories, and flag islands. However, the Governors remain committed to the development of policies and utilization of state energy endowments that result in the maximum benefit for their citizens, the region, and the nation.

3. Western energy production is indispensable to meeting national energy demands. The West is the energy breadbasket of the United States:

   a. Western states have all high-yield geothermal energy capacity in the continental United States.

   b. Western states supply the majority of non-federal United States petroleum.

   c. Western states are at the forefront of unconventional natural gas production.

   d. The Pacific Northwest produces the largest output of hydropower in the nation.

   e. Western states have the largest contiguous areas of wind power resources in the nation.

   f. The Southwest has some of the highest-identified solar energy resource areas in the United States.

   g. Western states produce the largest portion of coal in the United States, which is the fuel that constitutes the largest share of the national electricity generation mix.

   h. The West has the largest contiguous areas of high-yield biomass energy resource potential in the nation.

   i. Western states have nuclear power generation facilities and produce all domestic uranium.

4. Western states, Pacific territories, and flag islands have the resources to drive job creation and economic development through broad growth in the energy industry.

5. The Merchant Marine Act of 1920 has prevented certain noncontiguous states, territories, and flag islands from being supplied with domestically produced energy commodities.

B. GOVERNORS' POLICY STATEMENT

1. Western Governors recognize the following as energy policy priorities for the West:

   a. Secure the United States' energy supply and systems, and safeguard against risks to cybersecurity and physical security.

   b. Ensure energy is clean, affordable, and reliable by providing a balanced portfolio of renewable, non-traditional, and traditional resources.

   c. Increase energy efficiency associated with electricity, natural gas, and other energy sources and uses to enhance energy affordability and to effectively meet environmental goals.

   d. Advance efficient environmental review, siting, and permitting processes that facilitate energy development and the improvement and construction of necessary electric grid (transmission and distribution) and pipeline infrastructure, while ensuring environmental and natural resource protection.

   e. Improve the United States' electric grid's reliability and resiliency.

   f. Protect western wildlife, natural resources, and the environment, including clean air and clean water, and strive to reduce greenhouse gas emissions.

   g. Make the West a leader in energy education, technology development, research, and innovation.

   h. Utilize an all-of-the-above approach to energy development and use in the West, while protecting the environment, wildlife, and natural resources.

2. Western Governors support increasing the development and use of energy storage, alternative transportation fuels, and alternative vehicles.

3. Western Governors call on the federal government to lift a barrier to domestic free trade between the contiguous United States and the noncontiguous states, territories and U.S. flag islands by the Merchant Marine Act of 1920 by allowing those jurisdictions to receive energy commodities produced in the mainland but transported by foreign vessels, should those jurisdictions, and the jurisdictions whose ports are being used to ship these materials, desire it.

4. Redundant federal regulation of energy development, transport, and use is not required where sufficient state, territorial, or flag island regulations exist. Existing state authority should not be replaced or impeded by Congress or federal agencies.

C. GOVERNORS' MANAGEMENT DIRECTIVE

1. The Governors direct WGA staff to work with Congressional committees of jurisdiction, the Executive Branch, and other entities, where appropriate, to achieve the objectives of this resolution.

2. The Governors also direct WGA staff to consult with the Western Interstate Energy Board to recommend updates to the 10-Year Energy Vision that provide detail on the Governors' energy policy objectives outlined in this resolution.

3. Furthermore, the Governors direct WGA staff to consult with the Staff Advisory Council regarding its efforts to realize the objectives of this resolution and to keep the Governors apprised of its progress in this regard.

Western Governors enact new policy resolutions and amend existing resolutions on a biannual basis. Please consult www.westgov.org/policies for the most current copy of a resolution and a list of all current WGA policy resolutions.

Energy Vision for the West

Introduction

The resource-rich West supplies a majority of the country's energy resources and electric power. The United States is currently projected to become a net energy exporter within five years. The increase in natural gas developed in the West, coupled with increased investment in renewable and alternative energy sources, have positioned the region and its Governors to play a central role in the nation's economy and energy policy.

The West's vast energy resources and the Governors' role in the development of energy policy underscores the value of a regional energy policy, the *Energy Vision for the West*. This policy does not impede states or territories from approaching energy choice and industry growth based on their own resource endowments and policies. It illustrates that Western Governors have coalesced around common issues and specific goals, despite diverse geography, resources, and politics. The *Energy Vision for the West* elaborates on the Governors' objectives set forth in WGA Policy Resolution 2018-04, *Energy in the West*.

Western Governors support a comprehensive energy portfolio for the West to ensure that energy is clean, affordable, and reliable. They are also committed to energy policies that promote economic growth and protect the environment. This approach facilitates a strong economy and jobs across a variety of professions, skill sets, and educations.

This approach also recognizes that there are challenges and opportunities associated with every type of energy resource and use, the costs and benefits of which must be considered in policymaking. One such opportunity – and challenge – is creating an effective state-federal partnership in energy development, lands management, and environmental protection. This regional policy is a guide for realizing opportunities to advance the West as the nation's principal energy provider and a leader in energy innovation and effective policy.

Goal 1: Secure the United States' energy supply and systems, and safeguard against risks to cybersecurity and physical security.

Addressing threats to the nation's energy systems and resources is a high priority of Western Governors. Coordination between states, the federal government, and the private sector on energy emergency planning and response is vital to addressing physical and cybersecurity impacts on the West's energy systems and resources. To this end, the Governors establish the following objectives:

- Work with the Department of Defense to meet its national security mission by ensuring safe and secure onsite and off-site electricity generation for key defense installations.

- Continue to reduce reliance on non-North American oil imports from unstable foreign sources through individualized state-by-state solutions, such as increasing North American production, improving fuel efficiency, and developing renewable and alternative fuels.

- Ensure there is sufficient domestic energy supply, including domestic renewable electric generation, to meet existing and new market demand.

- Identify security and other vulnerabilities of energy infrastructure and create programs and standards to defend infrastructure from cyber and physical attacks, as well as natural disasters.

- Encourage effective relationships between state agencies, federal agencies, public utilities, and the private sector to prevent and prepare for risks to the region's energy supply and systems, as well as to respond to and recover from disruptions.

- Partner with the federal government to ensure the provision of adequate funding and access to resources for state emergency planning, response, and recovery.

- Expand, upgrade, and secure transmission and pipeline infrastructure, as well as ensure that all federal pipeline safety measures are efficiently implemented.

Goal 2: Ensure energy is clean, affordable and reliable by providing a balanced portfolio of renewable, non-traditional and traditional resources.

Western Governors believe that a balanced energy portfolio should consist of energy sources that are clean, affordable and reliable, that maintain system reliability, and limit rapid rate increases. These resources also require the maintenance and expansion of transmission and distribution infrastructure. To this end, the Governors establish the following objectives:

- Recognize the importance of western renewable (wind, solar, biomass, biofuels, geothermal, hydropower), nuclear, coal and natural gas resources, and the generation facilities that utilize those resources.

- Adapt utility regulation to changing markets, technologies, and resources.

- Encourage the addition of renewable, low-carbon, and clean generation, including utility-scale and distributed generation.

- Promote, advance and fund the evolution of new technologies, including carbon capture and advancements in renewable energy.

- Maintain the Rural Energy for America (REAP) program, which has benefited farmers, ranchers and rural businesses that are often underserved by other federal energy efforts.

Goal 3: Increase energy efficiency associated with electricity, natural gas, and other energy sources and use to enhance energy affordability and to effectively meet environmental goals.

Eliminating waste and using resources wisely are cornerstones of a sound energy strategy. State and local governments, utilities, households, and businesses are currently realizing the economic and other benefits of energy efficiency, but there are still substantial gains to be made. To this end, the Governors establish the following objectives:

- Prioritize energy efficiency associated with electricity, natural gas, and vehicle transportation.

- Enhance utility rate designs, including time-varying rates, and cost-effective utility energy efficiency programs that deliver electricity and natural gas savings to consumers.

- Support energy efficiency programs that provide incentives and rebates to lower the incremental up-front costs of energy efficiency technologies; Energy Service Company (ESCO) programs; and where successful, utility ratepayer-funded energy efficiency programs, including the use of rate decoupling.

- Encourage the retrofit of residential and commercial buildings and improve the energy efficiency of new buildings, such as through building energy codes and programs that stimulate energy efficient construction.

- Decrease energy intensity using tools such as combined heat and power and waste heat to power systems.

- Incorporate systems strategies to improve efficiency throughout the building lifecycle and to improve grid connectivity, including energy systems that enable two-way, automated utility-to-customer communications to facilitate demand response programs.

- Maintain funding and support long-term authorization for the State Energy Program (SEP), Weatherization Assistance Program (WAP), and Low-Income Home Energy Assistance Program (LIHEAP).

Goal 4: Advance efficient environmental review, siting and permitting processes that facilitate energy development and the improvement and construction of necessary electric grid (transmission and distribution) and pipeline infrastructure, while ensuring environmental and natural resource protection.

Responsible energy development and a robust, well maintained energy delivery system are vital to the economy and quality of life in the West. To this end, the Governors establish the following objectives:

- Encourage responsible leasing and development of energy resources and infrastructure.

- Create a clear and transparent process for regulation and permitting, coordinated among well-trained and adequately funded federal, state and local agencies.

- Streamline project-permitting reviews to minimize timelines, without compromising environmental and natural resource protection or states' roles in those processes.

- Maintain state and local decision-making authority over transmission line siting and permitting.

- Encourage regional transmission planning organizations to conduct interconnection-wide planning with the full participation of the states and with consideration of state energy policies.

- Create functional partnerships among states, federal agencies, tribal governments and local jurisdictions to solve conflicts that hinder energy infrastructure and resource development.

- Increase cooperation on interstate projects through interstate compacts and other tools.

- In the West-wide energy corridor process, ask federal agencies to guarantee: ongoing, substantive, and meaningful state consultation; consideration of state plans, processes, priorities, and policies; and integration of other streamlining efforts.

Goal 5: Improve the United States electric grid's reliability and resiliency.

Changes in energy generation, distribution, and management are transforming the nation's electric grid. But these advancements also highlight the need for grid level investment, along with associated updates for electricity regulation and policy. To this end, the Governors establish the following objectives:

- Protect state authority to determine the type and amount of new generation facilities and the programs used to procure new generation, recognizing that each state has their own priorities and portfolios.

- Protect state authority to encourage continued operation of existing generation facilities through long-term contracts, retail utility contracting, or other incentives.

- Encourage regional reliability organizations, utilities, state agencies and public utility commissions to assess the provision of essential reliability services under future scenarios that include a changing resource mix in the West.

- Support grid operator situational awareness of distributed energy resources by promoting coordination between utilities and distributed energy resource developers.

- Preserve areas of exclusive state authority regarding distributed energy resources, including storage, and improve utility distribution systems planning for distributed energy resources to enhance grid reliability and resilience.

- Improve understanding of grid resources and services and the need for new power production facilities and transmission/distribution infrastructure through data, analysis, and coordination.

- Prepare for potential disruptions to the grid from wildfires, flooding, earthquakes, tornadoes, cyberattacks and other disturbances and emergencies, as well as increase the grid's ability to withstand and reduce the magnitude of such events.

- Enable utilities to take necessary actions to enhance grid reliability and reduce the threat of wildfires to and from electric transmission and distribution rights-of-way.

Goal 6: Protect western wildlife, natural resources and the environment, including clean air and clean water, and strive to reduce greenhouse gas emissions.

Western states have long assumed a stewardship role for the natural environment and have worked across state lines to protect air, land, wildlife and water. Western Governors are committed to ensuring that energy development is done in an environmentally responsible manner. To this end, the Governors establish the following objectives:

- Promote energy technologies and sources that lower emissions.
- Continue advancing air and water quality improvements and plans in each state and across state lines.
- Foster environmental cooperation that: protects the state-federal partnership; provides for sustainable environmental protection; is nimble and flexible; and ensures that state governments play a key role in regulation.
- Acknowledge that a productive economy and responsible development can support environmental protection by providing additional funding and opportunities for public-private partnership.
- Encourage technologies that reduce water consumption, prioritize water consumption for traditional activities (drinking water, agriculture, habitat conservation/restoration), and contribute to the responsible development of new energy resources.
- Achieve a balance between the responsible development of energy projects and wildlife conservation.
- Urge the federal government to identify and approve solutions for the long-term storage and permanent disposal of spent nuclear fuel and nuclear waste.
- Encourage the development and deployment of a full range of technologies that offer the potential for cost-effective reductions in greenhouse gas emissions from energy production and use, including carbon capture and storage, energy efficiency, zero emissions generation sources, and other emerging options.

Goal 7: Make the West a leader in energy education, technology development, research, and innovation.

Effective energy policy is facilitated by an understanding of a common set of impartial facts and scientific evidence. Furthermore, the advancement of technology will play a critical role in realizing a clean energy future. To this end, the Governors establish the following objectives:

- Leverage the vast expertise in the West's industry, academic institutions, and national laboratories to make the region an international hub for new energy technology research and development, as well as energy education.
- Encourage Congress and the Department of Energy to support and fund research, development, demonstration, and deployment of advanced energy technologies.
- Create public-private research and development partnerships among industry, academia, the national labs, and federal agencies to identify promising new technologies, including energy efficiency technologies that advance clean energy with reduced environmental impacts.
- Encourage market operators, reliability organizations, and utilities to appropriately share electric system operational data with researchers, educators, and entrepreneurs to promote

electric system innovation and technology development, while still safeguarding against risks to cybersecurity and physical security.

- Encourage training and education in energy-related fields and ensure there is an adequate workforce operating under the highest safety standards.
- Facilitate the creation of employment opportunities for displaced energy sector workers.
- Educate the public regarding: the role of energy in maintaining a high standard of living and quality of life; trade-offs and externalities associated with all types of energy development and consumption; the coexistence of a healthy environment and a thriving economy; and how federal policy on public lands impacts energy and infrastructure development.

Goal 8: Utilize an all-of-the-above approach to energy development and use in the West, while protecting the environment, wildlife and natural resources.

A diverse energy portfolio is essential to the provision of clean, affordable, secure, and reliable energy. Western Governors support a comprehensive energy portfolio, including: oil, gas, coal, nuclear, biomass, geothermal, hydropower, solar, wind, and conservation and energy efficiency. To this end, the Governors establish the following objectives:

- Reduce costs and risks for the environmentally sound development of all energy resources.
- Ensure competition in the market for all resources.
- Recognize the growing importance of consumer choice in driving energy policy.
- Support consumer choice of distributed energy resources to achieve affordability, environmental, and other objectives.
- Increase the development and use of alternative transportation fuels and vehicles, including the necessary infrastructure for those vehicles.
- Encourage innovation and application of energy storage, including pumped hydro storage, battery storage, and compressed air energy storage where cost-effective.
- Support the responsible and efficient development and use of traditional and renewable resources.
- Increase the amount of electricity generated from new, retrofitted, or relicensed hydroelectric facilities, including small, irrigation, and flood control hydropower projects.
- Restore financing for the geothermal exploration program financed by the Department of Energy.
- Accelerate the introduction of small modular reactors into the marketplace.