Williams Allwein & Moser, LLC
Attorneys at Law
1500 W. Third Avenue, Suite 330, Columbus, OH 43212 Tel: 614-429-3092

December 18, 2014

Via Electronic Filing

Ms. Barcy McNeal, Secretary
Docketing Division
Public Utilities Commission of Ohio
180 E. Broad Street 11th Fl
Columbus, Ohio 43215-3793

RE: Sarah Jackson Redacted, Direct Testimony in PUCO Case No. 14-841-EL-SSO, et al, – Filed September 26, 2014.

Dear Ms. McNeal,

On September 26, 2014, Sierra Club filed the public (redacted) version of Sarah Jackson's direct testimony in Case Nos. 14-841-EL-SSO and 14-842-EL-SSO. It appears the document as filed did not ensure sufficient protection of the material deemed confidential by Duke Energy. This document was removed from the docket upon discovery of this issue. Sierra Club appreciates the prompt action by the docketing staff.

Sierra Club is re-submitting this testimony as an amended document with the same redactions. The amended document redactions were employed with adequate technology to ensure greater protection of this confidential material.

Please feel free to contact me with any questions regarding this filing.

Thank you,

/s/ Christopher J. Allwein

Christopher J. Allwein
Counsel for SIERRA CLUB

Cc: Parties of Record

ATTACHMENT

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Establish A Standard Service Offer Pursuant To Section 4928.143 Revised Code, In The Form Of An Electric Security Plan, Accounting Modifications And Tariffs For Generation Service	)	Case No. 14-841-EL-SSO
In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Amend Its Certified Supplier Tariff, P.U.C.O. No. 20	)	Case No. 14-842-EL-ATA

DIRECT TESTIMONY OF

SARAH E. JACKSON

ON BEHALF OF

SIERRA CLUB

CONTAINS HIGHLY CONFIDENTIAL MATERIAL

September 26, 2014

INTRODUCTION

Q Please state your name, business address, and position.

A My name is Sarah E. Jackson. I am an Associate at Synapse Energy Economics, Inc. (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts.

Q Please summarize your work experience and educational background.

A I have over ten years of experience analyzing federal and state regulations, policies, and environmental planning documents for municipal governments, consumer advocate clients, and environmental organizations. I have been a consultant at Synapse for three years, where I apply my experience to evaluate the impacts of policies and regulations on the electric sector, the costs and impacts of electricity production options, and the environmental compliance assumptions used by utilities in major regulatory filings. I also specialize in electricity market rules, trends, and analysis. I provide ongoing monitoring and advocacy services for Synapse's New England Power Pool (NEPOOL) clients, including the Maine and New Hampshire consumer advocates, PowerOptions, Vermont Energy Investment Corporation, and Conservation Services Group. As part of this work, I maintain Synapse's end user and alternative resource sector clients' interests at ISO-New England stakeholder meetings, assist clients in navigating RTO market rules, and develop reports examining key market issues.

I have provided consulting services for various clients, including the U.S. Environmental Protection Agency (EPA), the National Association of State Utility Consumer Advocates (NASUCA), the Regulatory Assistance Project (RAP), the Maine Office of the Public Advocate, the New Hampshire Office of the Consumer Advocate, the Massachusetts Attorney General's Office, PowerOptions, Vermont Energy Investment Corporation, and Conservation Services Group the Union of Concerned Scientists (UCS), Sierra Club, Earthjustice, Natural Resources Defense Council (NRDC), Citizens Action Coalition of Indiana, the Civil Society Institute, and Clean Wisconsin.

Prior to joining Synapse, I worked for six years as a research and policy analyst at the not-for-profit law firm Earthjustice in Oakland, California, where I analyzed the impacts of proposed federal, state, and local regulations, policies, and environmental compliance plans, with a focus on air emissions and energy.

I hold a bachelor's degree from Mount Holyoke College and a Master of Environmental Law and Policy from Vermont Law School.

My full curriculum vitae is attached as Exhibit SEJ-1.

Q Have you previously testified before the Public Utilities Commission of Ohio?

A No, I have not.

Q What is the purpose of your testimony?

A I was retained by Sierra Club to review Duke Energy Ohio's (Duke or the Company) application, supporting testimony, workpapers, and discovery in this proceeding, focusing on the proposed "Price Stabilization Rider" (PSR). My testimony is directed to the PSR proposal and the potential risks it poses to ratepayers.

Q Please describe the Company's proposed PSR.

A In its Electric Security Plan (ESP) application, Duke is proposing that it not use the energy and capacity from its contractual rights in OVEC to serve its standard service offer (SSO or non-shopping) customers.[1] Instead, one hundred percent of the OVEC energy and capacity to which Duke is entitled would be sold into the PJM wholesale market.[2] The costs allocated to Duke from OVEC (nine percent of the total fixed and variable costs associated with OVEC's two coal-fired generating plants) would be passed on to customers, less any market revenue generated from sales, through a non-bypassable rider the Company is calling a

[1] Duke Energy Ohio Application, Volume I, p. 13.
[2] Direct testimony of William Don Wathen in support of Duke Energy Ohio's Electric Security Plan, p. 11.

"Price Stabilization Rider."[3] If market revenues from the sale of the OVEC generation are greater than the allocated OVEC costs, the amount would be credited to Duke's customers; but if the allocated OVEC costs are greater than market revenues, then customers would be charged the difference. The PSR would remain in effect for the entire length of Duke's contractual obligation with OVEC – through June 2040.[4]

Q Please summarize your major conclusions and recommendations regarding the PSR.

A I conclude that the PSR may be adverse to the public interest and contrary to the State of Ohio's transition to competitive retail markets. I recommend that the Commission deny the Company's proposal to establish this rider.

The PSR could be adverse to state and public interests in several ways:

- This type of rate adjustment mechanism is inappropriate in a competitive retail market environment, as it seeks to effectively shift all of the risk from Duke's contractual obligations with the Ohio Valley Electric Corporation (OVEC) to customers, who will essentially become owners of generation they are not directly using.
- Duke's application and pre-filed testimony offer no analysis of the potential impacts its proposed PSR would have on its customers for the lifetime of the rider, therefore, the Commission, ratepayers, and intervenors are unable to determine whether the proposed PSR would have net costs or net benefits to customers over the next twenty five years.
- Information obtained through discovery suggests that for the period of the proposed Electric Security Plan (June 2015 – May 2018), and at least

[3] *Id*. at 13.
[4] *Id.*

through 2024, the proposed PSR will result in cumulative net [redacted] consumers.

- Finally, the cost of power from the OVEC assets could increase significantly in the coming years as regulations addressing carbon and other environmental regulations lead to increased compliance obligations for coal-fired power plants like OVEC's Kyger and Clifty Creek plants. If the cost of power outstrips market prices, Duke's customers will never realize any financial benefits from the PSR.

PSR ANALYSIS

Q What is the Company's stated reason for the proposed PSR?

A Company witness Wathen describes the proposed PSR as "a financial arrangement intended to act as a hedge against price volatility that exists in the PJM Interconnection, L.L.C., (PJM) power markets."[5] Company witness Henning states that the proposed PSR would "serve to mitigate some of the volatility in overall rates that customers pay for generation service."[6]

Q Are the OVEC assets the only resources to which the PSR will apply?

A The PSR is initially intended to cover only the Company's share of the OVEC generation, but witness Henning explains that the rider "could be expanded to include similar financial arrangements with other generators…"[7]

Q Please briefly describe the OVEC assets.

A OVEC (and its wholly owned subsidiary) owns and operates two large coal-fired power plants as well as a transmission system that connects these generating facilities to the networks of other utilities. The Kyger Creek plant in Cheshire,

[5] Direct testimony of William Don Wathen at 12.
[6] Direct testimony of James P. Henning in support of Duke Energy Ohio's Electric Security Plan, pp. 8-10.
[7] Direct testimony of James P. Henning at 10.

Ohio can generate 1,086 MW, and the Clifty Creek plant near Madison, Indiana has capacity to generate 1,303 MW. Both plants began operating in 1955.[8]

Q Is the proposed PSR rider consistent with the state's transition to a competitive retail market?

No. The proposed PSR is not an appropriate mechanism for the Company to manage market price risk in a competitive market environment. The Commission has almost finished transitioning its four largest utilities to a fully competitive retail energy market. Duke is already required to purchase electricity for its SSO customers through Commission-administered competitive auctions. These auctions are designed to insulate customers from price volatility through elements such as the use of staggered procurement and multiple products of varying durations (1-year, 2-year, 3-year, etc.). The resulting rates represent a blending of these various auctions, plus a markup, and are, therefore, more stable than market-based prices.

The proposed PSR would shift all costs (net of any market revenues) from Duke's portion of the OVEC generation to customers for the next twenty five years and would require customers to pay for generation that is not competitively bid in the SSO auction. This concept runs counter to the state's transition to a fully competitive retail market. In essence, the proposed PSR would turn Duke's customers into unwitting merchant generators, forcing them to take on substantial market risk without allowing them any control over costs, strategic decisions, or bidding strategies.

Furthermore, the proposed PSR imposes long-term cost risks on customers that will limit their ability to take advantage of other, potentially less expensive means of mitigating market price volatility in the future. The Company is locking customers in to paying for its OVEC generation costs for the next twenty five years, whether or not those units are economic.

[8] OVEC Annual Report – 2013 p. 1, available at http://www.ovec.com/FinancialStatements/AnnualReport-2013-Signed.pdf

Q Did the Company prepare an estimate of the amount of costs or benefits that might accrue to customers as a result of the proposed PSR?

No, not for the full lifetime of the PSR. This twenty five year commitment represents an investment in the OVEC plants that should be properly analyzed by the Company for the full length of the obligation. However, in response to Sierra Club discovery request SIERRA-INT-3-059 asking whether the Company is forecasting a net benefit to ratepayers through 2040, Duke responded: "The Company has not performed the requested analysis." Company witness Wathen repeatedly refers to the proposed PSR as a "benefit" to customers, but offers no substantive analysis supporting this characterization. He says only that "[a]t times of very low prices, there may be a charge flowing through to customers as the output of OVEC will have less value vis-à-vis market prices. But when market prices are very high, such as the prices seen in PJM during the recent polar vortex, the profits from OVEC would serve to benefit customers by reducing overall rates."[9] Mr. Wathen does not provide an estimate of what market prices would need to be to translate into net revenues for customers on a monthly or annual basis, nor does he define what "very low prices" would lead to costs to customers. Remarkably, Duke provides no information indicating whether this long-term commitment is cost-effective.

Q Were you able to obtain any information indicating potential costs or benefits to consumers from the proposed PSR?

A Yes. In response to discovery requests OEG-DR-01-001 and OCC-INT-16-413, Duke provided highly confidential attachments showing projected [redacted] and [redacted][10]

[9] Direct testimony of William Don Wathen at 14.

[10] See Highly Confidential Exhibit SEJ-2 attached and See Highly Confidential Exhibit SEJ-3.

Q **What does this information indicate in terms of potential costs or benefits for customers during this period?**

A These responses show that, by the Company's own estimates, over the period of the proposed ESP the PSR rider would result in a net present [redacted] to Duke's customers of over [redacted].[11] [redacted] Confidential Figure 1 below illustrates the net effect the PSR rider will have on customers through 2024.

[redacted]

The Company's analysis suggests that while annual cash flows will [redacted], the total cumulative net impact to [redacted] The analysis suggests there may eventually be some benefit from the proposed PSR, but the near-term risks are substantial while the long-term risk is based on much more speculative assumptions.

[11] See Highly Confidential Exhibit SEJ-3.

Q **What are the key assumptions used in making this projection?**

A The Company makes a number of key assumptions that influence the projection of potential costs and benefits to customers. First, the Company assumes that energy prices [redacted] The Company also assumes that energy costs [redacted] This contributes to the next assumption—[redacted] Finally, the Company assumes [redacted]

Taken together, these assumptions suggest that, [redacted] as illustrated in Confidential Figure 2, below.

[redacted]

Source: OEG-DR-01-001_Attachment_HIGH CONF

Q How does the Company explain these assumptions?

A In response to Sierra Club discovery requests SIERRA-INT-03-072 HIGHLY CONF and OCC-INT-16-414 HIGHLY CONFIDENTIAL, the Company explains the reasoning behind a number of these assumptions.

First, the Company explains that its projected energy prices [redacted] The Company states that the [redacted][12] [redacted][13]

Next, the Company explains that it expects energy costs [redacted] The Company also expects [redacted][14]

The Company projects [redacted] Duke explains that it is [redacted][15]

Finally, the Company explains that its [redacted][16]

---

[12] See Highly Confidential Exhibit SEJ-4 and Highly Confidential Exhibit SEJ-5.
[13] See Highly Confidential Exhibit SEJ-4.
[14] See Highly Confidential Exhibit SEJ-4.
[15] See Highly Confidential Exhibit SEJ-4.

Q What is the significance of the Company's assumptions with respect to energy market prices?

A The Company's assumptions regarding energy market prices are important because they represent the "market price risk" facing the OVEC assets, and, by virtue of the proposed PSR, the risk facing Duke's customers. The Company is proposing to sell all of its entitlement to OVEC generation into the PJM wholesale market. The amount of future generation multiplied by the forecast energy price determines the energy revenue that can be expected from the OVEC generation. The gross revenue (energy and capacity) minus the total costs for generation is the net revenue stream passed on to customers through the proposed PSR. If the Company's assumptions about energy prices are incorrect and energy prices turn out to be lower, gross revenues will be reduced and cumulative net revenue [redacted]

It is important to note that Duke's [redacted][17] [redacted] Confidential

Figure 3, below, illustrates the Company's [redacted]

[redacted]

[16] See Highly Confidential Exhibit SEJ-4 and Highly Confidential Exhibit SEJ-6.
[17] See Highly Confidential Exhibit SEJ-4; Highly Confidential Exhibit SEJ-5; Highly Confidential Exhibit SEJ-6, and Highly Confidential Exhibit SEJ-7.

[redacted]

Source: OEG-DR-01-001_Attachment_HIGH CONF

[redacted][18] [redacted]

The imposition of a price on carbon would make coal plants like Kyger and Clifty Creek less competitive with energy market prices, since energy prices reflect a mix and coal, natural gas, and zero-carbon renewables. This would suggest these plants would be less economic under a carbon-constrained future, as it would not make sense for an effective carbon adder to improve performance at coal-fired units.

[18] See Highly Confidential Exhibit SEJ-4.

Q **What is the significance of the Company's assumptions with respect to future generation volumes?**

A The Company's assumptions regarding future generation volumes are important because they affect the quantity of annual generation over which fixed costs are recovered in the market. Since the total capacity of the OVEC plants and Duke's percent equity interest therein (9 percent) have not changed, the Company is clearly anticipating [redacted] Indeed, Confidential Figure 4 below shows average historical capacity factors for the OVEC plants [redacted]

[redacted]

Source: OEG-DR-01-001_Attachment_HIGHLY CONF and EIA Form 923(5A)

[redacted]

Furthermore, as mentioned above, the imposition of a carbon price starting in 2020 would be expected to affect coal plant costs more than energy market prices, making these plants less competitive. This expectation would lead to these plants being utilized less under a carbon-constrained future, [redacted].

Q What is the significance of the Company's assumptions with respect to capacity prices?

A The Company's assumptions regarding future PJM capacity prices are important because they affect how much revenue the Company earns from selling its OVEC generation into the capacity market. If capacity prices turn out to be lower than expected by the Company, it would reduce the total revenue available for pass-through to customers.

Q Is it possible that the proposed PSR will never provide net benefits to customers?

A [redacted]

FUTURE ENVIRONMENTAL COMPLIANCE RISKS

Q What additional cost risks do these OVEC assets face?

A One significant risk facing the OVEC assets is pending carbon regulations. The U.S. EPA recently proposed a rule under Section 111(d) of the Clean Air Act to regulate carbon emissions from existing electric sector sources. If this rule is finalized as expected in June of 2015, it will likely require reductions in carbon emissions from coal-fired power plants like Kyger and Clifty Creek.

Other environmental regulations also pose risks that may lead to higher costs for these units in the future. While the Kyger and Clifty Creek coal plants are fairly well-controlled from a criteria air pollutant standpoint and appear to be in the process of upgrading water and waste controls, over the next twenty five years these facilities are likely to be impacted by increasingly stringent environmental controls.

A number of regulations covering air, water, and waste pollution from electric generators have been proposed or are under development by the EPA that could increase compliance costs at Kyger and Clifty Creek. These include Effluent Limitations Guidelines and Standards (ELG), Disposal of Coal Combustion Residuals (CCR), Section 316(b) Cooling Water Intake Structures at Existing

Facilities rule (316b), National Ambient Air Quality Standards (NAAQS) for ozone, PM, and sulfur dioxide, and the Cross State Air Pollution Rule (CSAPR).

Q How does the Company's CO_2 price forecast compare to forecasts used by other utilities?

A Synapse tracks the state of CO_2 policy and regulation and utility views of regulatory initiatives, which we make available to the public. Synapse has recently released an updated carbon price discussion paper and forecast, attached as Exhibit SEJ-8. We break our forecast into a bounded region of likely prices, all starting in 2020. The mid-case starts at $15/ton in 2020 and rises to $60/ton by 2040 (2012$); this case represents our best estimate of a reasonable base case. The attached discussion paper details the background and assumptions underlying the forecast.

The Company only included its [redacted]

Q Is the Company's assumed CO_2 price sufficient to account for the risks from current and potential future carbon regulations?

A Maybe. [redacted] the PSR is proposed to remain in place through June 2040. During that time, additional carbon regulations above and beyond the EPA's 111(d) rule may increase costs for coal-fired generation such as the OVEC plants.

Q What other future environmental costs has the Company included in its forecasts?

A The Company's estimates include costs for several planned environmental projects. In response to discovery request OEG-DR-01-003, Duke provided a confidential attachment entitled [redacted] In this document, OVEC lays out the projected costs of environmental controls that will be installed at the Kyger and Clifty Creek plants [redacted]

[redacted]. The controls appear to be planned to comply with [redacted]

Q Do these costs appear to be reasonable estimates for complying with these rules?

A Since the Company did not provide any of the requested information regarding these environmental projects, it is not possible to fully assess whether the projects will be adequate to meet these environmental rules at the costs identified in OEG-DR-01-003 CONF ATTACH. However, based on my own assessment, it appears that [redacted]. Without more information, I am unable to determine whether OVEC's estimates for meeting [redacted]

Q Is there a risk that these rules could require additional compliance costs over the lifetime of the PSR?

A Yes. Each of these rules requires periodic review and update. It is likely that in the next 25 years these rules will be revised to include additional controls.

Q Please briefly describe the purpose and impact of National Ambient Air Quality Standards (NAAQS).

A NAAQS set maximum air quality limitations that must be met at all locations across the nation for specific pollutants. Compliance with the NAAQS can be determined through data collected from air quality monitoring stations or through air quality dispersion modeling. If, upon evaluation, a state has areas found to be in "nonattainment" of a particular NAAQS, the state is required to set enforceable requirements to reduce emissions from sources contributing to nonattainment such that the NAAQS are attained and maintained. EPA has established short-term and/or annual NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter (measured as particulate matter less than or equal to 10 micrometers in diameter (PM_{10}) and particulate matter less than or equal to 2.5 micrometers in diameter ($PM_{2.5}$)), and lead. EPA is required to periodically review and evaluate the need to strengthen the NAAQS if necessary to protect public health and welfare. For example, EPA is currently evaluating the NAAQS for ozone and is likely to make that standard more stringent based on the latest science regarding health effects.

In nonattainment areas, sources must comply with emission reduction requirements known as "Reasonably Available Control Technology" (RACT) to bring the areas into attainment of the NAAQS. New major sources, including major modifications at existing sources, must comply with very strict emissions reductions consistent with "lowest achievable emissions reductions" (LAER) as well as obtain emission offsets.

Q: Which NAAQS are most likely to impact the OVEC plants?

A The 1-hour SO_2 NAAQS, the 8-hour Ozone NAAQS, and the $PM_{2.5}$ NAAQS are likely to have the greatest impacts on coal-fired units.

Q Please briefly describe the 1-hour SO_2 NAAQS.

A In 2010, the EPA promulgated a new 1-hour standard for SO_2, which became effective in June of that year. The new 1-hour SO_2 standard set a limit—75 ppb or 195 µg/m3—on the allowable concentration of SO_2 in the ambient air for each hour of the day. An area is in compliance with—or attaining—the standard if the three-year average of the fourth highest daily maximum 1-hour average concentration for each year is less than or equal to 75 ppb.

As mentioned above, for most NAAQS, EPA determines whether an area is attaining the standard by reviewing ambient air quality monitoring data from the area. With SO_2, however, EPA found that, due to the limited geographic coverage of the existing monitoring network, there was not sufficient monitoring data available in all areas to determine whether the standard was being met. Because of these data limitations, and because of the "source-oriented" nature of the 1-hour

SO_2 standard, EPA determined that refined dispersion modeling may also be used to determine whether an area with significant SO_2 sources meets the standard.[19]

Q What is the current status of the 1-hour SO2 NAAQS?

A In July 2013, EPA made initial "non-attainment" designations for a limited number of areas that had sufficient monitoring data to demonstrate noncompliance with the 1-hour SO_2 standard. EPA found that only 29 areas in 16 states had sufficient monitoring data to make these initial non-attainment findings.[20] In Indiana, four areas spanning five counties were designated non-attainment in the first round of designations.[21] In Ohio, four areas covering parts of six counties were designated as non-attainment.[22] The Company's units are located in Jefferson County, Indiana (Clifty Creek) and Gallia County, Ohio (Kyger Creek), where compliance status has not yet been determined. Another round of designations is anticipated based on either the installation of new ambient air monitors or the submission of dispersion modeling.

Q What are the implications of the 1-hour SO_2 NAAQS for OVEC's assets?

A The next round of non-attainment designations will likely be focused on areas with significant sources of SO_2 emissions. If dispersion modeling shows that the SO_2 emissions from the Kyger and Clifty Creek plants are causing or contributing to violations of the 1-hour SO_2 NAAQS, the areas could be designated as non-attainment areas and OVEC may need to take steps to further reduce SO_2 emissions at the plants.

[19] U.S. Environmental Protection Agency, "Next Steps for Area Designations and Implementation of the Sulfur Dioxide National Ambient Air Quality Standard," February 6, 2013.

[20] US EPA, 2013. Final Nonattainment Areas for the 2010 SO2 Standards, Round 1 – July 2013. http://www.epa.gov/airquality/sulfurdioxide/designations/pdfs/july2013SO2nonattainmentcounties.pdf

[21] EPA Green Book, Indiana SO_2 Nonattainment Areas (2010 Standard), available at: http://www.epa.gov/airquality/greenbook/inso2_2010.html

[22] EPA Green Book, Ohio SO_2 Nonattainment Areas (2010 Standard), available at: http://www.epa.gov/airquality/greenbook/ohso2_2010.html

Q **Please briefly describe the 8-hour Ozone NAAQS.**

A In March 2008, EPA strengthened the 8-hour ozone standard from 84 ppb to 75 ppb. On September 16, 2009, EPA announced that because the 2008 standard was not as protective as recommended by EPA's panel of science advisors, it would reconsider the 75 ppb standard. In January 2010, EPA proposed lowering the 75 ppb primary ozone standard to between 60 and 70 ppb.

On September 2, 2011, however, the Administration announced that EPA would not finalize its proposed reconsideration of the 75 ppb standard ahead of the Agency's normal 5-year NAAQS review cycle. The next 5-year review for 8-hour ozone was initiated at the end of 2013 and is on-going.

If EPA were to finalize a standard in the 60 to 70 ppb range (as it proposed in 2010), it is likely that additional areas in Ohio and Indiana will be designated as non-attainment for the new standard. This could drive significant additional NOx emission reduction requirements. Specifically, it would mean that Clifty Creek Unit 6 would likely need to be retrofit with Selective Catalytic Reduction (SCR) in order to comply with a more stringent 8-hour ozone standard.[23] My capital cost estimate for an SCR on Clifty Creek Unit 6 is $136 million. This is not an engineering estimate but rather a reasonable estimate based on publicly available cost estimates developed by Sargent & Lundy.[24] This SCR may be needed before the current 8-hour ozone standard is released due to the reinstatement of CSAPR, described later in the section.

Q **Please briefly describe the $PM_{2.5}$ NAAQS.**

A In 1997, the EPA established the first ever annual and 24-hour $PM_{2.5}$ NAAQS at 15 micrograms per cubic meter ($\mu g/m^3$) and 65 $\mu g/m^3$, respectively. In 2006, the EPA lowered the 24-hour $PM_{2.5}$ standard to 35 $\mu g/m^3$ and retained the 15 $\mu g/m^3$

[23] *See* OVEC Annual Report – 2013, p. 29 available at: http://www.ovec.com/FinancialStatements/AnnualReport-2013-Signed.pdf

[24] EPA IPM v.5.13 Appendix 5-3 (Sargent & Lundy) – *Revisions to Cost and Performance for APC Technologies: SCR Cost Development Methodology*, available at: http://www.epa.gov/powersectormodeling/docs/v513/attachment5_3.pdf

annual standard. The 2006 PM2.5 standards were primary drivers behind the EPA's 2005 CAIR and 2011 CSAPR rules, which were designed to lower NOx and SO_2 emissions from electric generating units in affected states that significantly contribute to $PM_{2.5}$ non-attainment areas in other states.

In December 2012, EPA lowered the annual $PM_{2.5}$ standard from 15 $\mu g/m^3$ to 12 $\mu g/m^3$ and retained the 24-hour standard at 35 $\mu g/m^3$. EPA will make final area designations for the new standard by December 2014, at which time states with non-attainment areas will have three years to develop a state implementation plan (SIP) outlining how they will reduce pollution to meet the standard by 2020.

Particulate matter is made up of primary particles, which are emitted directly from a source, as well as secondary particles, which are formed through reactions in the atmosphere of chemicals such as SO_2 and NOx.[25] The $PM_{2.5}$ NAAQS, therefore, requires control of not just directly emitted particles but also of SO_2 and NOx – the precursors of secondary particles.

Q Please briefly describe the purpose and impact of the Cross State Air Pollution Rule.

A The Cross State Air Pollution Rule (CSAPR), finalized in 2011, established the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's $PM_{2.5}$ and ozone non-attainment problems. Though CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia on August 21, 2012, in April 2014, the U.S. Supreme Court reversed the Appeals Court and reinstated CSAPR. EPA is still in the process of determining how it will implement the reinstated rule, whose original compliance deadlines have already passed. In the meantime, the 2005 Clean Air Interstate Rule remains in place to maintain states' "good neighbor" obligations.

[25] EPA Particulate Matter website: http://www.epa.gov/air/particlepollution/basic html

Q How will the $PM_{2.5}$ and Ozone NAAQS, and the reinstated CSAPR impact Kyger and Clifty Creek plants?

A NOx is a precursor to both $PM_{2.5}$ and ozone, meaning that areas that are not in attainment for these two pollutants will seek the most effective source controls for precursors. Since large emissions sources – such as coal-fired generating stations – contribute disproportionately to emissions of these precursors and are effectively controlled with post-combustion controls such as SCR (selective catalytic reduction), I assume that if areas of Ohio and Indiana within the dispersion area of the Kyger and Clifty Creek plants are found to be in non-attainment for the $PM_{2.5}$ or ozone standards, the state and EPA could require rigorous NOx controls at these units to meet the standards. The EPA withdrew the last draft update to the ozone NAAQS, but had that NAAQS been promulgated as proposed, most of the monitors in Ohio and southern Indiana would show violations,[26] and hence require these states to develop rigorous SIPs with tight limits on NOx emissions from major sources.

Similarly, if the original interstate transport rule is reinstated, large NO_x sources in Ohio and Indiana could either be required to install additional controls or purchase NO_x allowances at high prices. This would almost certainly require the installation of an SCR on Clifty Creek Unit 6 before 2020.[27] Under the proposed PSR, Duke customers would be required to pay Duke's nine percent of the total capital costs to install the SCR. As stated above, my estimate for an SCR on Clifty Creek Unit 6 is approximately \$136 million.

Furthermore, based on the promulgation of new $PM_{2.5}$ NAAQS and expected ozone NAAQS, I'd expect that the next version of CSAPR will be more rigorous than the original rule.

[26] *See* http://www.epa.gov/airquality/ozonepollution/pdfs/CountyPrimaryOzoneLevels0608.pdf
[27] *See* OVEC Annual Report – 2013, p. 29 available at: http://www.ovec.com/FinancialStatements/AnnualReport-2013-Signed.pdf

Q Is OVEC aware of the potential need for an SCR on Clifty Creek unit 6?

A Yes. In its 2013 Annual Report, OVEC states that "additional NOx allowances or additional NOx controls may be necessary for Clifty Creek Unit 6 either under a reinstated CSAPR rule or any promulgated replacement rule." With that rule now reinstated, it seems very likely that additional NOx controls will be required at Clifty Creek Unit 6.

CONCLUSIONS AND RECOMMENDATIONS

Q What are your findings?

A I find that the proposed PSR is not an appropriate mechanism for Duke to hedge market price volatility on behalf of its customers. It would shift all costs (net of any market revenues) from Duke's portion of the OVEC generation onto customers and would require customers to pay for generation that they are not directly using and that is not competitively bid in the SSO auction. This is counter to the state's transition to a fully competitive retail market.

Furthermore, the proposed PSR imposes long-term cost risks on customers that will limit their ability to take advantage of other, potentially less expensive means of mitigating market price volatility in the future. The Company is locking customers in to paying for OVEC generation costs for the next twenty five years, whether or not those units are economic or provide any benefit to customers.

The Company's own analysis shows that the proposed PSR will [redacted]

Finally, as environmental standards, including carbon regulations, continue to be adopted and updated, the OVEC plants are likely to face additional compliance costs during the lifetime of the PSR.

Q What are your recommendations to this Commission?

A I recommend that the Commission deny the Company's request for the proposed PSR and not allow these risks to be passed on to Duke's customers.

Q Does this conclude your testimony?

A Yes, it does. However, I reserve the right to update or supplement my testimony based on new information that may become available.

Sarah E. Jackson, Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 2 I Cambridge, MA 02139 I 617-453-7060
sjackson@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc, Cambridge, MA. *Associate*, September 2011 – present.

Analyze economic and environmental implications of renewable portfolio standards and clean energy policy scenarios. Investigate electricity market price trends and fluctuations. Maintain our end user and alternative resource sector clients' interests at ISO-NE and PJM stakeholder meetings. Assist clients in navigating RTO market rules, especially regarding reliability assessments for coal-fired power plants and participation of energy efficiency and distributed generation in wholesale capacity markets.

Earthjustice, Oakland, CA. *Research and Policy Analyst*, 2005 – 2011.

Analyzed federal, state, and local regulations, policies, and environmental planning documents in support of clean air and climate change campaigns. Drafted substantial comment letters on priority issues, often leading to significant policy changes. Advocated at public hearings critiquing proposed policies or regulatory actions. Developed and maintained strong relationships with federal, state, and local agency staff, client groups, community and grassroots groups, technical and scientific experts, and key media contacts. Developed factual basis for and evaluated environmental significance of lawsuits to advance clean air and climate change campaigns.

Central Valley Air Quality Coalition, Central Valley, CA.

Chair, Watchdog Committee, 2007 – 2011.

Analyzed and prioritized federal, state, and local regulatory and legislative activities affecting air quality in California's Central Valley. Managed and coordinated with technical consultants on complex regional air pollution clean-up plans. Educated and mobilized committee members and affected communities to participate on priority issues. Developed and facilitated technical trainings and educational events for coalition members and citizens.

Steering Committee Member, 2005 – 2011.

Managed and set policy priorities for a diverse coalition of more than 75 community, public health, faith, environmental, and environmental justice organizations and individuals working for clean air in California's Central Valley. Helped develop Strategic Plan for advancing policy priorities and making coalition more effective.

Kopelman & Paige, P.C., Boston, MA. *Land Use Paralegal*, 2003 – 2005

Performed legal research on subjects such as wetlands protection, coastal management, legality of municipal bylaws, and validity of comprehensive permits in support of Land Use department.

Reviewed and prepared administrative records, briefs, litigation status reports, and other legal documents.

Governor's Office of Energy and Community Services, Concord, NH. *Energy Program Intern*, 2001

Assisted in the research and organizational stages of drafting a State Energy Plan. Participated in the initial implementation of the Energy, Environmental & Economic Integration Project. Special projects relating to energy efficiency and renewable energy.

EDUCATION

Vermont Law School, South Royalton, VT
Master of Environmental Law and Policy, 2003

Mount Holyoke College, South Hadley, MA
Bachelor of Arts in English and Environmental Studies, 2001

PUBLICATIONS

Luckow, P., E. A. Stanton, B. Biewald, S. Fields, S. Jackson, J. Fisher, F. Ackerman. 2014. *CO_2 Price Report, Spring 2014: Includes 2013 CO_2 Price Forecast.* Synapse Energy Economics.

Keith, G., S. Jackson, J. Daniel, K. Takahashi. 2014. *Idaho's Electricity Sources: Current Sources and Future Potential.* Synapse Energy Economics for the Idaho Conservation League.

Ackerman, F., S. Jackson, S. Fields. 2014. *Sustainable Development for the Navajo Nation: Replacing the Navajo Generating Station with Renewable Energy*. Synapse Energy Economics for Chorus Foundation.

Stanton, E.A., J. Daniel, F. Ackerman, S. Jackson. 2013. *Review of EPA's June 2013 Steam Electric Effluent Limitations and Guidelines (40 CFR Part 423).* Synapse Energy Economics for Earthjustice, Environmental Integrity Project, and Sierra Club.

Jackson, S., P. Peterson, D. Hurley, T. Woolf. 2013. *Forecasting Distributed Generation Resources in New England: Distributed Generation Must Be Properly Accounted for in Regional System Planning.* Synapse Energy Economics for E4 Group.

Whited, M., D. White, S. Jackson, P. Knight, E.A. Stanton. 2013. *Declining Markets for Montana Coal*. Synapse Energy Economics for Northern Plains Resource Council.

Keith, G., S. Jackson, A. Napoleon, T. Comings, J. Ramey. 2012. *The Hidden Costs of Electricity: Comparing the Hidden Costs of Power Generation Fuels.* Synapse Energy Economics for Civil Society Institute.

Fisher, J., S. Jackson, B. Biewald. 2012. *The Carbon Footprint of Electricity from Biomass: A Review of the Current State of Science and Policy*. Synapse Energy Economics.

Peterson, P., D. Hurley, S. Jackson, M. Schultz. 2012. *The Road to Better System Planning: ISO-New England's Revised Energy Efficiency Forecast*. Synapse Energy Economics for Connecticut Office of Consumer Counsel.

Resume dated May 2014

Highly Confidential Exhibit SEJ-2

Redacted

Highly Confidential Exhibit SEJ-3

Redacted

Highly Confidential Exhibit SEJ-4

Redacted

Highly Confidential Exhibit SEJ-5

Redacted

Highly Confidential Exhibit SEJ-6

Redacted

Highly Confidential Exhibit SEJ-7

Redacted

CO_2 Price Report, Spring 2014

Includes 2013 CO_2 Price Forecast

May 22, 2014

AUTHORS

Patrick Luckow
Elizabeth A. Stanton
Bruce Biewald
Spencer Fields
Sarah Jackson
Jeremy Fisher
Frank Ackerman

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

1. EXECUTIVE SUMMARY

Prudent planning requires electric utilities and other stakeholders in carbon-intensive industries to use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. However, forecasting a CO_2 price can be difficult. While several bills have been introduced in Congress, the federal government has yet to legislate a policy to reduce greenhouse gas emissions in the United States.

Although this lack of a defined policy setting a price on carbon poses a challenge in CO_2 price forecasting, an assumption that there will be no CO_2 price in the long run is not, in our view, reasonable. The scientific basis for attributing climatic changes to human-driven greenhouse gas emissions is irrefutable, as are the type and scale of damages expected to both infrastructure and ecosystems. The need for a comprehensive U.S. effort to reduce greenhouse gas emissions is clear. Any policy requiring or leading to greenhouse gas emission reductions will result in higher costs to the electricity resources that emit CO_2.

This Spring 2014 report updates Synapse's November 2013 Carbon Dioxide Price Forecast with the most recent information on federal regulatory measures, state and regional climate policies, and utility CO_2 price forecasts. The Synapse CO_2 price forecast is designed to provide a reasonable range of price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. We have not reevaluated the forecast itself. We have only reviewed and updated our summary of the key regulatory developments and data from utility IRPs, which are frequently changing and crucial to understanding the impetus for a carbon price forecast and the number of utilities that have adopted one for planning purposes. The Low, Mid and High Synapse CO_2 price forecasts presented in this report are identical to those published in the November 2013 report.[1] We continue to refer to this forecast as the 2013 forecast. We plan to release another edition of this report later in 2014, in which we will revisit the 2013 forecast.

1.1. Key Assumptions

This report includes updated information on federal regulations, state and regional climate policies, and utility CO_2 price forecasts. The low, mid, and high Synapse CO_2 price forecasts presented here are identical to those in the November 2013 report. Synapse's November 2013 CO_2 price forecast reflected our expert judgment that near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term cap-and-trade or carbon tax legislation passed by Congress, will result in significant pressure to decarbonize the electric power sector. The key assumptions of our forecast included:

[1] Luckow P., E. Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman. *2013 Carbon Dioxide Price Forecast*. Synapse Energy Economics, November 2013.

- A federal program establishing a price for greenhouse gases is the probable eventual outcome, as it allows for a least-cost path to emissions reduction.
- Initial climate-focused policy actions are more likely to take a regulatory approach, e.g. Section 111(d) of the Clean Air Act. In the longer term, federal legislation setting a price on emissions through a cap-and-trade policy or a carbon tax will likely be prompted by one or more of the following factors:
    - New technological opportunities that lower the cost of carbon mitigation;
    - A patchwork of state policies that achieve state emission targets for 2020, spurring industry demands for federal action;
    - A series of executive actions taken by the President that spur demand for Congressional action;
    - A Supreme Court decision that permits lawsuits, making it possible for states to sue companies within their boundaries that own high-carbon-emitting resources, and creating a financial incentive for energy companies to act; and
    - Mounting public outcry in response to increasingly compelling evidence of human-driven climate change.

Given the growing interest in reducing greenhouse gas emissions by states and municipalities throughout the nation, a lack of timely, substantive federal action will result in the enactment of diverse state and local policies. Heterogeneous—and potentially incompatible—sub-national climate policies would present a challenge to any company seeking to invest in CO_2-emitting power plants, both existing and new. Historically, there has been a pattern of states and regions leading with energy and environmental initiatives that have in time been superseded at the national level. It seems likely that this will be the dynamic going forward: a combination of state and regional actions, together with federal regulations, that are eventually eclipsed by a comprehensive federal carbon price.

We expect that federal regulatory measures together with regional and state policies will lead to the existence of a cost associated with greenhouse gas reductions in the near term. Prudent utility planning requires that utilities take this cost into account when engaging in resource planning, even before a federal carbon price is enacted.

1.2. Study Approach

In this report, Synapse reviews several key developments that have occurred over the past six months. These include:

- Proposed federal regulatory measures to limit CO_2 emissions from new power plants and administrative initiatives to advance regulation for existing units;
- Revisions to the Northeast's Regional Greenhouse Gas Initiative (RGGI) CO_2 policy and the most recent auctions under both RGGI and California's AB 32 Cap-and-Trade program;

- Synapse's collection and analysis of carbon price forecasts from the most recent IRP efforts of 46 utilities.

1.3. Synapse's 2013 CO_2 Price Forecast

Based on analyses of the sources described in Synapse's November 2013 Carbon Dioxide Price Forecast report, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. We have not reevaluated these forecasts since the November 2013 report. Figure ES-1 (below) shows the range covered by the Synapse forecasts. These projections assume that state and regional policies will combine with federal regulatory measures to put economic pressure on carbon-emitting resources in the next several years such that the costs of operating a high-carbon-emitting plant increase—followed later by a broader federal, market-based policy. In states other than the RGGI region[2] and California, we assume a zero carbon price for the next several years; by 2020, we expect that federal regulatory measures will begin to put economic pressure on carbon-emitting power plants throughout the United States. All annual carbon prices are reported in 2012 dollars per short ton of CO_2.[3]

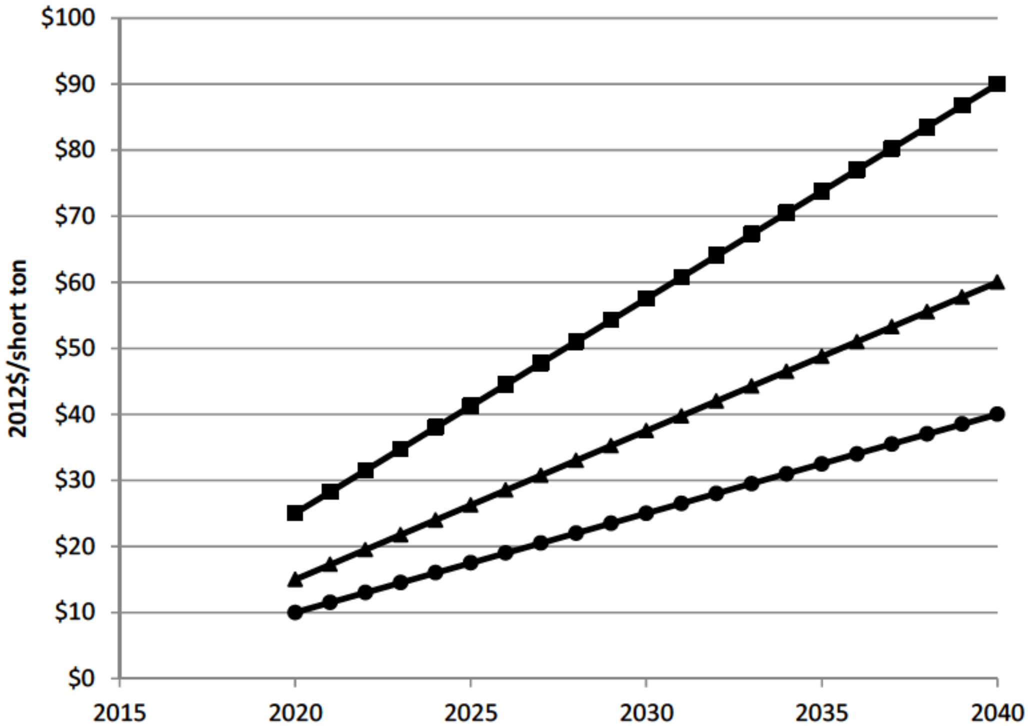
Each of the forecasts shown in Figure ES-1 represents a different level of political will for reducing carbon emissions, as described below.

- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 per ton in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technological alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

[2] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[3] Results from public modeling analyses were converted to 2012 dollars using price deflators taken from the U.S. Bureau of Economic Analysis, and are available at: http://www.bea.gov/national/nipaweb/SelectTable.asp. Consistent with U.S. Energy Information Administration and U.S. Environmental Protection Agency modeling analyses, a 5 percent real discount rate was used in all levelization calculations.

ES-1: Synapse 2013 CO_2 Price Trajectories



2. Structure of this Report

This report presents Synapse's 2013 Low, Mid and High CO_2 price forecasts, along with the evidence assembled to inform these forecasts, and key updates to this evidence that reflect developments from the past six months:

- Section 3 discusses broader concepts of CO_2 pricing.
- Sections 4 through 8 discuss existing state and federal legislation, potential future legislation, recent cap-and-trade results from the research community, and a range of current CO_2 price forecasts from utilities.
- Section 9 presents Synapse's 2013 Low, Mid, and High CO_2 price forecast, along with a comparison to recent utility forecasts.

Unless otherwise indicated, all prices are in 2012 dollars and CO_2 emissions are given in short tons.

3. WHAT IS A CARBON PRICE?

There are several co-existing meanings for the term "carbon price" or "CO_2 price": each of these meanings is appropriate in its own context. Here we give a brief introduction to five common types of carbon prices, along with a quick guide to which of the carbon price estimates reviewed in this report are based on which of these meanings. (Note that the definition of an additional term—the "price of carbon"—is ambiguous because it can at times mean several of the following.)

Carbon allowances (sometimes called credits or certificates, and best known for their use in policies called "cap and trade"): Allowances are certificates that give their holder the right to emit a unit of a particular pollutant. A fixed number of carbon allowances are issued by a government, some sold and, perhaps, some given away.[4] Subsequent trade of allowances in a secondary market is common to this policy design. The price that firms must pay to obtain allowances increases their cost of doing business, thereby giving an advantage to firms with cleaner, greener operations, and creating an incentive to lower emissions whenever it can be done for less than the price of allowances. The number of allowances—the "cap" in the cap-and-trade system—reflects the required society-wide emission reduction target. A greater reduction target results in a lower cap and a higher price for allowances. In the field of economics, pricing emissions is called "internalizing an externality": the external (not borne by the polluting enterprise) cost of pollution damages is assigned a market price (thus making it internal to the enterprise).

In this report: The Northeast's RGGI and California's Cap-and-Trade Program are both carbon allowance trading systems. In addition, the Kerry-Lieberman, Waxman-Markey, and Cantwell-Collins bills all proposed policy measures that included carbon allowance trading.

Carbon tax: A carbon tax also internalizes the externality of carbon pollution, but instead of selling or giving away rights to pollute (the allowance approach), a carbon tax creates an obligation for firms to pay a fee for each unit of carbon that they emit. In theory, if the value of damages were known with certainty, a tax could internalize the damages more accurately, by setting the tax rate equal to the damages; in practice, the valuation of damages is typically uncertain. In contrast to the government issuance of allowances, with a carbon tax there is no fixed amount of possible emissions (no "cap"). A cap-and-trade system specifies the amount of emission reduction, allowing variation in the price; a tax specifies the price on emissions, allowing variation in the resulting reductions. In both cases there is an incentive to reduce emissions whenever it can be done for less than the prevailing price. In both cases there is the option to continue emitting pollution, at the cost of either buying allowances or paying the tax. While some advocates have claimed that a tax is administratively simpler and reduces bureaucratic, regulatory, and compliance costs, a general aversion to new taxes has meant that no carbon tax proposals have received substantial support in recent policy debate.

---

[4] Regardless of whether allowances are initially given away for free or sold, they represent an opportunity cost of emissions to the holder.

Effective price of carbon (sometimes called the notional, hypothetical, or voluntary price): Carbon allowances and carbon taxes internalize the climate change externality by making polluters pay. However, many other types of climate policies work not by making polluting more expensive per se, but instead by requiring firms to use one technology instead of another, or to maintain particular emission limitations in order to avoid legal repercussions. Non-market-based emission control regulatory policies are called “command and control.” For any such non-market policy there is an “effective” price: a market price that—if instituted as an allowance or tax—would result in the identical emission reduction as the non-market policy. An effective price may be used internally within a firm, government agency, or other entity to represent the effects of command and control policies for the purpose of improved decision making. Renewable Portfolio Standards, energy efficiency measures, and other policies designed to mitigate CO_2 emissions impose an effective price on carbon.

In this report: Utility carbon price forecasts are effective prices used for state-required IRPs and internal planning purposes. The U.S. Environmental Protection Agency’s (EPA’s) proposed carbon pollution standard for new sources of electric generation is a non-market-based policy that would represent an effective price.

Marginal abatement cost of carbon: An abatement cost refers to an estimate of the expected cost of reducing emissions of a particular pollutant. Estimation of a marginal abatement cost requires the construction of a “supply curve”: all of the possible solutions to controlling emissions (these may be technologies or policies) are lined up in order of their cost per unit of pollution reduction. Then, starting from the least expensive option, one tallies up the pollution reduction from various solutions until the desired total reduction is achieved, and then asks: what would it cost to reduce emissions by the last unit needed to achieve the target? The answer is the “marginal” cost of that level of pollution reduction; a greater reduction target would have a higher marginal cost. The marginal abatement cost of carbon is not a market price used to internalize an externality. Rather, it is a method for estimating the price that, if it were applied as a market price, would have the effect of achieving a given emission reduction target. In a well-functioning cap-and-trade system, the allowance price would tend towards the marginal abatement cost of carbon.

In this report: We do not analyze any marginal abatement costs in this report—see the *2012 Synapse Carbon Dioxide Price Forecast* for further information.[5] McKinsey & Company has been a consistent producer of this type of analysis, an example being its 2010 report *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*.

Social cost of carbon: Whereas the marginal abatement cost estimates the price of stopping pollution, the social cost of carbon estimates the cost, per unit of emissions, of allowing pollution to continue. The social cost of carbon is the societal cost of current and future damages related to climate change resulting from the emission of one additional unit of pollutant. Estimating the uncertain costs of

[5] Wilson et al. *2012 Carbon Dioxide Price Forecast.* Synapse Energy Economics, October 2012. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.

uncertain future damages from uncertain future climatic events is, of course, a tricky business. If enough information were available, a marginal abatement cost for each level of future emissions (the supply of emission reductions) could be compared to a social cost of carbon for each level of future emissions (the demand for emission reductions) to determine an "optimal" level of pollution (such that the next higher unit of emission reduction would cost more to achieve than its value in reduced damages). More commonly, the social cost of carbon is used as part of the calculation of benefits of emission-reducing measures.

In this report: The U.S. federal government's internal carbon price for use in policy making is an estimate of the social cost of carbon.

4. FEDERAL CLIMATE ACTION IS INCREASINGLY LIKELY

In the near term, comprehensive federal climate legislation appears unlikely to come out of a divided Congress. The Executive Branch, however, is moving forward with regulatory actions to limit greenhouse gas emissions. Following a directive issued by President Obama, EPA released revised CO_2 performance standards for new power plants on September 20, 2013.[6] In June 2013, President Obama also instructed EPA to use its Clean Air Act authority to propose CO_2 standards for existing power plants by June 2014 and to finalize these standards by June 2015.[7] On March 31, 2014, the White House Office of Management and Budget (OMB) began a formal review of the EPA's standards for existing power plants.[8] Beyond the realm of electric sector CO_2 policies (which are the focus of this report), similar regulatory measures have been proposed for the transportation, buildings, and industrial sectors; policies enacted in other sectors include vehicle efficiency standards set to rise to 54.5 miles per gallon by 2025 for new cars and light-duty trucks, and new energy efficiency standards for federal buildings set to reduce energy consumption by nearly 20 percent.[9,10]

We continue to expect that a federal cap-and-trade program for greenhouse gases is the most likely policy outcome in the long term, because it permits reductions to come from sources that can mitigate emissions at the lowest cost. While state and regional policies combined with federal regulatory actions

---

[6] EPA. "2013 Proposed Carbon Pollution Standard for New Power Plants." Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

[7] Memorandum from President Obama to Administrator of the Environmental Protection Agency, Power Sector Carbon Pollution Standards (June 25, 2013). Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[8] Office of Information and Regulatory Affairs. "Pending EO 12866 Regulatory Review." Received 03/31/2014. http://www.reginfo.gov/public/do/eoDetails?rrid=123943.

[9] Vlasic, Bill. "US Sets Higher Fuel Efficiency Standards." *The New York Times*. August 28th, 2012. Available at: http://www.nytimes.com/2012/08/29/business/energy-environment/obama-unveils-tighter-fuel-efficiency-standards.html.

[10] "Energy Efficiency Design Standards for New Federal Commercial and Multi-Family High-Rise Residential Buildings." A Rule by the Department of Energy. July 9th, 2013. Available at: https://www.federalregister.gov/articles/2013/07/09/2013-16297/energy-efficiency-design-standards-for-new-federal-commercial-and-multi-family-high-rise-residential#h-9.

appear to be more likely than a federal cap-and-trade policy in the near term, according to a World Resources Institute (WRI) analysis these local measures are unlikely to be able to meet long-term goals of reducing total greenhouse gas emissions to 83 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[11]

4.1. Regulatory Measures for Reducing Greenhouse Gas Emissions

There are a number of federal regulations that directly and indirectly mandate a reduction in greenhouse gas emissions in the power sector. These are summarized in Table 1 and described in detail below.

[11] See WRI's analysis of these scenarios in the 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

Table 1: Summary of power sector regulatory measures that may result in reduced greenhouse gas emissions

Rule	Current Status as of Release	Next Deadline(s)	Pollutants Covered
Federal Regulations			
Clean Air Act, Section 111	~EPA released a revised 111(b) rule, New Source Performance Standards for GHGs from new sources, in September 2013	~Awaiting final rule	CO_2 and other greenhouse gases
	~A draft 111(d) rule controlling GHGs from existing sources was submitted on March 31, 2014	~June 2014: EPA must propose standards for existing power plants	
		~June 2015: EPA must finalize standards for existing power plants	
		~June 2016: States must submit State Implementation Plans (SIPs) to EPA	
National Ambient Air Quality Standards (NAAQS)	~1-Hour SO_2 NAAQS was finalized in June 2010	~Initial designations based on monitoring data were made in June 2013; additional designations expected by or before 2017	Sulfur dioxide; nitrogen dioxide; carbon monoxide; ozone; particulate matter; and lead
	~PM2.5 annual NAAQS was finalized on December 2012	~Final designations expected in December 2014; SIPs due three years later with attainment required by 2020	
	~8-Hour Ozone NAAQS was finalized in March 2008	~Final designations delayed until April 2012 and SIPs are due in 2015	
		~The standard is currently under review, proposed rule updating the standard is required in December 2014 and final rule by October 1, 2015	
Cross State Air Pollution Rule (CSAPR)	~The U.S. Supreme Court reinstated CSAPR in April 2014, finding that EPA had not exceeded its authority in crafting the rule	~CSAPR Phase II was to begin on January 1, 2014; EPA is in the process of determining new compliance deadlines for the reinstated CSAPR rule; CAIR requirements remain in place until then	Nitrogen oxides and sulfur dioxide
Mercury and Air Toxics Standards (MATS)	~Finalized in December 2011	~April 16, 2015: Compliance deadline (rule allows for a one-year extension if certain conditions are met)	Mercury, metal toxins, organic and inorganic hazardous air pollutants, and acid gases
Coal Combustion Residuals (CCR) Disposal Rule	~EPA first proposed to regulate CCR in June 2010	~EPA has signed a consent decree requiring the Agency to issue a final CCR rule by December 19, 2014	Coal combustion residuals (ash)
Steam Electric Effluent Guidelines (ELGs)	~EPA released a proposed rule with eight regulatory options in June 2013	~September 30, 2015: Rule for release of toxins into waterways must be finalized	Toxins entering waterways
Cooling Water Intake Structure (316(b)) Rule	~EPA released a final rule for implementation of Section 316(b) of the Clean Water Act on May 19, 2014	~Final rule becomes effective 60 days after publication in the Federal Register (likely ~August 2014) and requirements will be implemented in NPDES permits as they are renewed	Cooling water
Regional Haze Rule	~Regional Haze Rule issued in July 1999	~States must file SIPs and install the Best Available Retrofit Technology (BART) controls within 5 years of SIP approval	Sulfur oxides, nitrogen oxides, and particulate matter

Clean Air Act

As a result of the 2007 Supreme Court finding in *Massachusetts v. EPA*, greenhouse gas emissions were determined to be subject to the Clean Air Act and (in a later ruling) to contribute to air pollution anticipated to endanger public health and welfare. In 2009, EPA issued an "endangerment finding," obligating the agency to regulate emissions of greenhouse gases from stationary sources such as power plants.[12] EPA released draft New Source Performance Standards (NSPS) in April 2012 and revised NSPS standards in September 2013. The revised standards limit CO_2 emissions from new fossil-fuel power plants to 1,000-1,100 pounds of CO_2 per MWh (lbs/MWh)—a level achievable by a new natural gas combined-cycle plant. The exact limit of CO_2 emissions within that range depend on the type of plant and period over which the emission rate would be averaged.[13]

Under Section 111(d) of the Clean Air Act, the EPA is required to propose standards for existing power plants by June 2014, but there remains substantial uncertainty over what form these regulations will take. Unit-specific emission rates standards, such as the NSPS for greenhouse gases, are only one of several plausible options. Unit-specific standards could apply to power plants based on categories by fuel type and technology type, each with its own maximum emission rate. Units that are not in compliance could undertake upgrades to improve efficiency; however, these kinds of upgrades can be expensive, can only achieve small, one-time changes to emission rates, and could trigger New Source Review/Prevention of Significant Deterioration (NSR/PSD) provisions, increasing the cost further.[14,15]

Other regulatory design options for existing plants under 111(d) include maintaining a state-wide average maximum emission rate, and market-based (e.g., cap-and-trade) approaches. More flexible mechanisms like these could lower the cost of compliance, but could also result in additional legal challenges as compared to a simpler but more rigid system of unit-specific regulation.[16] An Edison Electric Institute white paper on potential regulation of existing sources notes that "because of concerns about legal challenges to the guidelines, EPA may be reluctant to incorporate a wide range of compliance flexibility mechanisms in the guidelines, but may be more receptive to such mechanisms if proposed by the states in compliance plans."[17]

---

[12] EPA. "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act." Available at: http://www.epa.gov/climatechange/endangerment/.

[13] EPA. "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units." Available at: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.

[14] EEI. "Existing Source GHGH NSPS White Paper," Page 5. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[15] Tarr J., Monast J., Profeta T. "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act." The Nicholas Institute. January 2013. Available at: http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf.

[16] Fine, Steven and MacCracken, Chris. "President Obama's Climate Action Plan: What It Could Mean to the Power Sector." ICF International. August 2013. Available at: http://www.icfi.com/insights/white-papers/2013/president-obama-climate-action-plan.

[17] Edison Electric Institute. "Existing Source GHG NSPS White Paper," Page 2. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

End-use energy efficiency may be an important part of a comprehensive compliance strategy for a regulation that averages emission rates across states. States may be able to achieve emissions reductions at a lower cost through the structures of their existing energy efficiency resource standards.

Methods for demonstrating compliance with 111(d) may be similar to existing regulations: in a process similar to Section 110 of the Clean Air Act, under which EPA sets National Ambient Air Quality Standards (NAAQS), states will be required to submit State Implementation Plans (SIPs) that specify how they intend to comply with 111(d). EPA can then decide whether a proposed SIP meets the terms of the regulation; in the absence of an acceptable SIP, EPA can impose a Federal Implementation Plan (FIP). Under the schedule outlined by President Obama in his Climate Action Plan, regulations for existing sources under 111(d) will be finalized by June 2015, and states will be required to submit SIPs to the EPA by June 2016. A draft 111(d) rule was sent to the Office of Management and Budget (OMB) for review on March 31, 2014.[18]

Performance standards for new and existing sources will affect decisions made by utilities regarding operation, expansion, and retirements. Enforcement of the Clean Air Act creates an opportunity cost of greenhouse gas abatement: prudent utilities will take Clean Air Act compliance into consideration in their planning, either explicitly as a maximum allowable emissions rate, or implicitly as an effective carbon price. An NRDC analysis of the impacts of 111(d) implementation estimated compliance costs under this policy at $7.53 per ton of CO_2 avoided.[19]

Other regulatory measures put economic pressure on carbon-intensive power plants

A suite of current and proposed EPA regulations require pollution-intensive power plants to install environmental controls for compliance. The cost of complying with environmental regulations reduces the profitability of the worst polluters, sometimes rendering them uneconomic. These policies demonstrate momentum towards appropriately regulating or pricing environmentally harmful activities in the electric sector. To the extent that plants with high emissions of other pollutants also have high carbon emissions, these policies would tend to *lower* the future CO_2 price necessary to achieve a given reduction; as more pollution-intensive plants retire in response to other EPA regulations, the necessary carbon price is reduced. Specific regulatory measures include:

- *National Ambient Air Quality Standards (NAAQS)* set maximum air quality limitations that must be met at all locations across the nation. EPA has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter—measured as particulate matter less than or equal to 10

[18] Office of Management and Budget. "Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions From Existing Stationary Sources: Electric Utility Generating Units." Received 03/31/2014. http://www.reginfo.gov/public/do/eoDetails?rrid=123943

[19] Natural Resources Defense Council. "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," March 2013. Available at: http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf.

micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)—and lead.

- *The Cross State Air Pollution Rule (CSAPR)*, finalized in 2011, establishes the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia in August 2012. The Supreme Court agreed to review the Appeals Court's decision, and on April 29, 2014, CSAPR was reinstated by the high court. Significantly, the Court found that EPA had not exceeded its authority in crafting an emission control program that utilized cap and trade and considered cost as a factor where the language of the Clean Air Act was ambiguous in addressing the complex problem of interstate transport of pollution.
- *Mercury and Air Toxics Standards (MATS)*: The final MATS rule, approved in December 2011, sets stack emissions limits for mercury, other metal toxins, organic and inorganic hazardous air pollutants, and acid gases. Compliance with MATS is required by 2015, with a potential extension to 2016. Many utilities have already committed to capital improvements at their coal plants to comply with the standard. In fact, the EIA recently found that 70 percent of U.S. coal-fired power plants already comply with MATS.[20]
- *Coal Combustion Residuals (CCR) Disposal Rule:* In June 2010, EPA proposed to regulate CCR for the first time, either under Subtitle C (used primarily for hazardous waste) or Subtitle D (municipal solid waste) of the Resource Conservation and Recovery Act. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required. In addition, the EPA would implement minimum requirements for dam safety at impoundments. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care. On January 29, 2014, EPA signed a Consent Decree with environmental groups promising to issue a final CCR rule by December 19, 2014.[21]
- *Steam Electric Effluent Limitation Guidelines (ELGs):* On June 7, 2013, EPA released eight regulatory options for new, proposed steam-electric ELGs to reduce or eliminate the release of toxins into U.S. waterways. A final rule is required by September 30, 2015.[22] New requirements will be implemented in 2015 to 2020 through the five-year National Pollutant Discharge Elimination System permit cycle.[23]
- *Cooling Water Intake Structure (§316(b)) Rule:* In March 2011, EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act

[20] See U.S. Energy Information Administration website. Accessed April 15, 2014. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=15611

[21] See January 29, 2014 Consent Decree. Available at: http://earthjustice.org/sites/default/files/files/044-1-Consent-Decree.pdf

[22] See U.S. Environmental Protection Agency website. Accessed April 15, 2014. Available at: http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm.

[23] See U.S. Environmental Protection Agency. Steam Electric ELG Rulemaking. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf.

at existing power plants that withdraw large volumes of water from nearby water bodies. Under this rule, EPA would set new standards to reduce the impingement and entrainment of fish and other aquatic organisms from cooling water intake structures at electric generating facilities. The final rule was released on May 19, 2014.The requirements of the rule will be implemented through renewal of a facility's NPDES permit, which must be renewed every five years. [24]

- *Regional Haze Rule:* The Regional Haze Rule, released in July 1999, requires states to develop implementation plans (SIPs) for reducing emissions that impair visibility at pristine areas such as national parks. The rule also requires periodic SIP updates to ensure progress is being made toward improving visibility. The initial development of SIPs, which is just now being completed, requires Best Available Retrofit Technology (BART) controls for SOx, NOx, and PM emissions on large emission sources built between 1962 and 1977 that are found to be contributing to visibility impairment. BART controls must be installed within five years of SIP approval.

4.2. Proposed Cap-and-Trade Legislation

Over the past decade, there have been several Congressional proposals to legislate cap-and-trade programs, with the goal of reducing greenhouse gas emissions by up to 83 percent below recent levels by 2050 through a federal cap. Such programs would allow trading of allowances to promote least-cost reductions in greenhouse gas emissions.

Comprehensive climate legislation was passed by the House in 2009: the American Clean Energy and Security Act, also known as Waxman-Markey or H.R. 2454. However, the Senate did not vote on either of the two climate bills before it in the 2009-2010 session (Kerry-Lieberman APA 2010 and Cantwell-Collins S. 2877). Waxman-Markey was a cap-and-trade program that would have required a 17 percent reduction in emissions from 2005 levels by 2020, and an 83 percent reduction by 2050.[25] Further analysis of these proposals is provided in Synapse's 2012 Carbon Dioxide Price Forecast.[26]

Congressional interest in climate policy has been ongoing. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S. 2146), which would have required larger utilities to meet a percentage of their sales with electric generation from sources that produce less greenhouse gas emissions than a conventional coal-fired power plant. Credits generated by these clean technologies would have been tradable with a market price. In February 2013, Senators Sanders and Boxer introduced new comprehensive climate change legislation, the Climate Protection Act of 2013. This bill

[24] See U.S. Environmental Protection Agency website. Accessed May 21, 2014. Available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm.

[25] U.S. Energy Information Administration (EIA); Energy Market and Economic Impacts of the American Power Act of 2010 (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html. EIA; Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

[26] Wilson et al., "2012 Carbon Dioxide Price Forecast," October 2012. http://www.synapse-energy.com/Downloads/SynapseReport. 2012-10.0.2012-CO2-Forecast.A0035.pdf.

proposed a carbon fee of $20 per ton of CO_2 or CO_2 equivalent content of methane, rising at 5.6 percent per year over a ten-year period. The bill has not yet been brought to a vote.

As discussed earlier, we expect that federal cap-and-trade legislation will eventually be enacted but that it is unlikely to happen in the near term. Federal carbon regulations are in effect or under development today, and the economic pressure—or opportunity cost—that they create may be represented as an effective price of greenhouse gas emissions. Regulatory measures are unlikely to meet long-term goals of reducing total greenhouse gas emissions to approximately 80 percent below 2005 levels by 2050, and a broader approach will be increasingly attractive in order to meet these goals at lower costs. Our judgment indicates this is most likely to take the form of a federal cap-and-trade system.

5. STATE AND REGIONAL CLIMATE POLICIES

There are two regional and state cap-and-trade programs in the United States today: the Northeast's RGGI and California's Cap-and-Trade Program under AB32. In addition, a total of 20 states plus the District of Columbia have set greenhouse gas emissions targets as low as 80 percent below 1990 levels by 2050.[27]

Recent Revisions to RGGI

RGGI is a cap-and-trade greenhouse gas program for power plants in the northeastern United States. Current participant states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. RGGI has had more than five years of successful CO_2 allowance auctions, with Auction 23 resulting in a clearing price of $4.00 per ton.[28] RGGI is designed to reduce electricity sector CO_2 emissions to at least 45 percent below 2005 levels by 2020.[29]

When RGGI was established in 2007, the expectation was that the CO_2 emissions allowance auction would generate revenues for consumer benefit programs such as energy efficiency, renewable energy, and clean energy technologies. While RGGI has provided significant revenues for consumer benefit, its allowance prices have generally remained near the statutory minimum price. External influences, including changes to fuel prices, caused a shift from coal and oil to lower-carbon natural gas generation.

[27] "Greenhouse Gas Emissions Targets." Center for Climate and Energy Solutions. Accessed September 13, 2013. Available at: http://www.c2es.org/us-states-regions/policy-maps/emissions-targets.

[28] RGGI Auction 23 results available at: http://rggi.org/market/co2_auctions/results/Auction-23.

[29] RGGI. "RGGI States Propose Lowering Regional CO_2 Emission Cap 45%, Implementing a More Flexible Cost-Control Mechanism." February 2013. Available at: http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf.

Compared to those external factors, the effect of the original RGGI cap requirements were relatively minor in meeting the goals of reducing CO_2 emissions in the power sector.[30]

In 2012 and 2013, the RGGI states evaluated a number of plans for tighter emissions caps with the goal of raising allowance prices. In February of 2013, participating states agreed to lower the CO_2 cap from 165 million to 91 million short tons in 2014, to be reduced by 2.5 percent each year from 2015 to 2020. RGGI analysis indicates that with these lower caps, allowance prices will rise to $4.16 per short ton in 2014, increasing to $10.40 per ton in 2020.[24]

In March 2014, the first auction under the new cap cleared at $4 per short ton. This auction used all available “cost containment reserve” allowances for the year—a fixed additional supply of allowances (above the cap) at a fixed price ($4 in 2014, rising to $10 in 2017) used to prevent rapid increases in the allowance price. Given that no more cost containment reserve allowances are available for the remaining three auctions in 2014, it is quite possible that prices in these auctions will clear above $4 per ton.

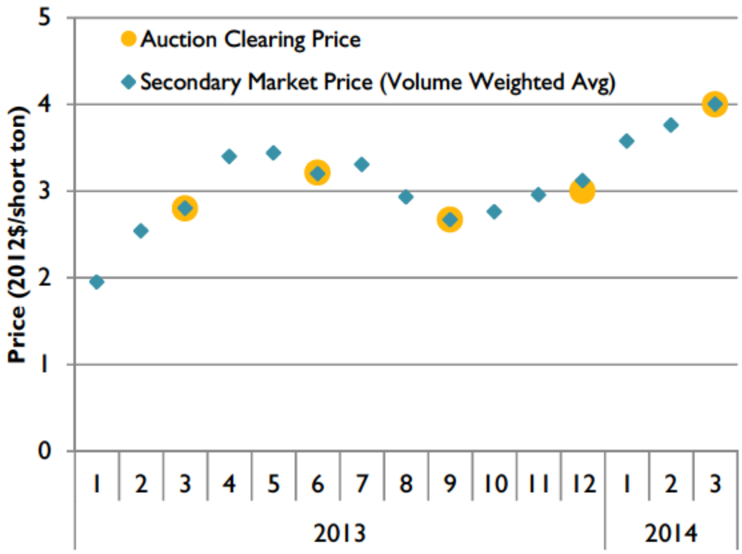
The March 2014 clearing price was the highest-ever clearing price at a RGGI auction. While the primary market for allowances is the official RGGI auction held four times per year, RGGI allowances can be resold to another party in the secondary market after an auction has concluded.[31] This secondary market allows firms to obtain allowances at any point during the year, not just the four official auctions, and allows for futures and options contracts, giving firms more opportunities to manage their risk. Secondary market prices have historically tracked auction prices closely, with both rising steadily since September 2013. Figure 1 shows secondary market prices and auction clearing prices since 2013. Prices rose in Q2 2013 with the announcement of the revised CO_2 cap, and—after a brief dip in the summer 2013—have risen in each month and quarter since September 2013.[32]

[30] Environment Northeast. “RGGI at One Year: An Evaluation of the Design and Implementation of the Regional Greenhouse Gas Initiative.” February 2010. Available at: http://www.env-ne.org/public/resources/pdf/ENE_2009_RGGI_Evaluation_20100223_FINAL.pdf.

[31] All secondary market transactions resulting in a transfer of allowance ownership are registered in RGGI’s CO_2 Allowance Tracking System (COATS).

[32] RGGI CO_2 Allowance Tracking System, Transaction Price Report. Accessed Mar. 28 2014. Available at: https://rggi-coats.org/eats/rggi/index.cfm.

Figure 1: RGGI auction clearing prices and secondary market prices



California's Cap-and-Trade-Program under AB32

With the goal of reducing the state's emissions to 1990 levels by 2020, California's Global Warming Solutions Act (AB32) has created the world's second largest carbon market, after the European Union's Emissions Trading System. The first compliance period for California's Cap-and-Trade Program began on January 1, 2013 and covers electricity generators, CO_2 suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 27,600 tons of CO_2e per year.[33,34] On February 19, 2014, the California Air Resources Board held its sixth quarterly allowance auction, resulting in a clearing price of $11.48 per ton.[35] This first phase of the program includes electricity generators and large industrials. Phase II, beginning in 2015, will also include transportation fuels and smaller industrial sources.

In 2014, the California Air Resources Board will auction at least 118 million allowances, up from 96 million allowances in 2013. The reserve price will increase from $10.71 per ton to $11.34 per ton, consistent with a requirement for the price to increase 5 percent every year plus the rate of inflation.[36]

On January 1, 2014, California and Québec formally linked their carbon markets, although the first joint auction will not be held until later in 2014. Québec is expected to be a net buyer from California. Québec's target will likely to be harder to meet: with an electricity system largely based on hydropower

---

[33] "CO_2e" refers to CO_2-equivalent, the combination of CO_2 and an equivalent value for other greenhouse gases.

[34] CARB 2013a. "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments by Linked Jurisdictions." July 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/ctlinkqc.pdf. Legislated value is 25,000 metric tons, converted here to short tons.

[35] CARB 2013b. "CARB Quarterly Auction 6, February 2014: Summary Results Report." February 24, 2014. Available at: http://www.arb.ca.gov/cc/capandtrade/auction/february-2014/results.pdf.

[36] California Carbon. "California to auction 118 million emission allowances in 2014, increases reserve price by 6%". December 2, 2013. Available at: http://californiacarbon.info/2013/12/02/california-to-auction-118-million-emission-allowances-in-2014-increases-reserve-price-by-6/.

and overall much smaller than California's, there are fewer easy opportunities for emissions reductions. Québec's March 4 auction cleared at $11.39 in Canadian dollars, similar in magnitude to California allowance prices.[37]

6. ASSESSMENT OF CARBON PRICE FOR FEDERAL RULEMAKING

In 2010, the U.S. federal government began including a carbon cost in regulatory rulemakings to account for the climate damages resulting from each additional ton of greenhouse gas emissions;[38] updated values were released in 2013.[39] The 2013 Economic Report of the President acknowledges that these values will continue to be updated as scientific understanding improves.[40] When updated values were released in 2013, the Office of Management and Budget (OMB) invited comments from interested parties. Several authors of this CO_2 price report submitted comments providing further analysis of the values used and the process used to develop them.[41]

An Interagency Working Group on the Social Cost of Carbon—composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, Department of Transportation, and Office of Management and Budget, among others—was tasked with the development of a consistent value for the social benefits of climate change abatement. Four values were developed (see Section 3 for more explanation of the "social cost of carbon" methodology). These values—$11, $36, $55, and $101 per ton of CO_2 in 2013, expressed in 2007$ and rising over time—represent average (most likely) damages at three discount rates, along with one estimate at the 95th percentile of the assumed distribution of climate impacts.[42,43] While subject to significant uncertainty,

---

[37] Morehouse, E. "California and Quebec: A Partnership Par Excellence." Environmental Defense Fund. March 7, 2014. Available at: http://blogs.edf.org/californiadream/2014/03/07/california-and-quebec-a-partnership-par-excellance/.

[38] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

[39] Interagency Working Group on the Social Cost of Carbon (2013) Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866. Available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

[40] 2013 Economic Report of the President (2013). Chapter 6. March 2013. Available at: http://www.whitehouse.gov/sites/default/files/docs/erp2013/ERP2013_Chapter_6.pdf.

[41] Stanton, E. A., F. Ackerman, and J. Daniel. 2014. "Comments on the 2013 Technical Update of the Social Cost of Carbon." Synapse Energy Economics for the Environment, Economics and Society Institute. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2014-01.0.SCC-Comments.14-008.pdf.

[42] These values represent recently revised costs for the SCC. Originally, these values were $5, $21, $35, and $65 per metric tonne for the year 2010 in 2007 dollars.

[43] In a 2012 paper, Ackerman and Stanton modified the Interagency Working Group's assumptions regarding uncertainty in the sensitivity of temperature change to emissions, the expected level of damages at low and high greenhouse gas concentrations, and the assumed discount rate, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater [Frank Ackerman and Elizabeth A. Stanton (2012). "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." *Economics: The Open-Access, Open-Assessment E-Journal*, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10]. Similarly, Laurie Johnson and Chris Hope modified

this multi-agency effort represents an initial attempt at incorporating the benefits associated with CO_2 abatement into federal policy.

As of May 2012, these estimates had been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[44, 45] In the first rule in which the revised 2013 values were used—improving energy efficiency in microwave ovens—the net present value of benefits over a 30-year timeframe increased by $400 million as a result of the increase in effective carbon price.[46] While a carbon price for federal rulemaking assessments is a fundamentally different kind of cost metric than the others discussed in this report, it nonetheless represents a dollar value for greenhouse gas emissions currently in use by the U.S. federal government.

7. RECENT CO_2 PRICE FORECASTS FROM THE RESEARCH COMMUNITY

The Energy Modeling Forum (EMF), a working group of government and private modeling teams, has been convening to explore energy system issues since the late 1970s. The group recently completed its EMF 24 analysis with the objective of evaluating what CO_2 price trajectories are consistent with proposed emission reduction targets under different technology scenarios. This analysis also incorporated several complementary policies with a cap-and-trade proposal, including: transportation emissions reduction through vehicle gas mileage standards; renewable portfolio standards in the electric sector; and mandates that all new coal facilities employ carbon capture and storage (CCS) technology—a policy similar to EPA's proposed NSPS for coal plants. Nine modeling teams participated in this study.[47]

discount rates and methodologies and found results up to 12 times larger than the Working Group's central estimate [Laurie T. Johnson, Chris Hope. "The social cost of carbon in U.S. regulatory impact analyses: an introduction and critique." *Journal of Environmental Studies and Sciences*, 2012; DOI: 10.1007/s13412-012-0087-7].

[44] Robert E. Kopp and Bryan K. Mignone (2012). "The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement." Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15.

[45] See, for example, "Rulemaking for Microwave Ovens Energy Conservation Standard: Technical Support Document." May 2013. Available at: http://www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx/ruleid/37.

[46] Brad Blumer. "The social cost of carbon is on the rise." The Washington Post, June 6th, 2013. Available at: http://articles.washingtonpost.com/2013-06-06/business/39789409_1_carbon-dioxide-emissions-obama-administration.

[47] Clarke, L.C., A.A. Fawcett, J.P. Weyant, V. Chaturvedi, J. MacFarland, Y. Zhou, "Technology and U.S. Emissions Reductions Goals: Results of the EMF 24 Modeling Exercise," and Fawcett, A.A., L.C. Clarke, S. Rausch, J.P. Weyant, "Overview of EMF 24 Policy Scenarios," both forthcoming in *The Energy Journal*.

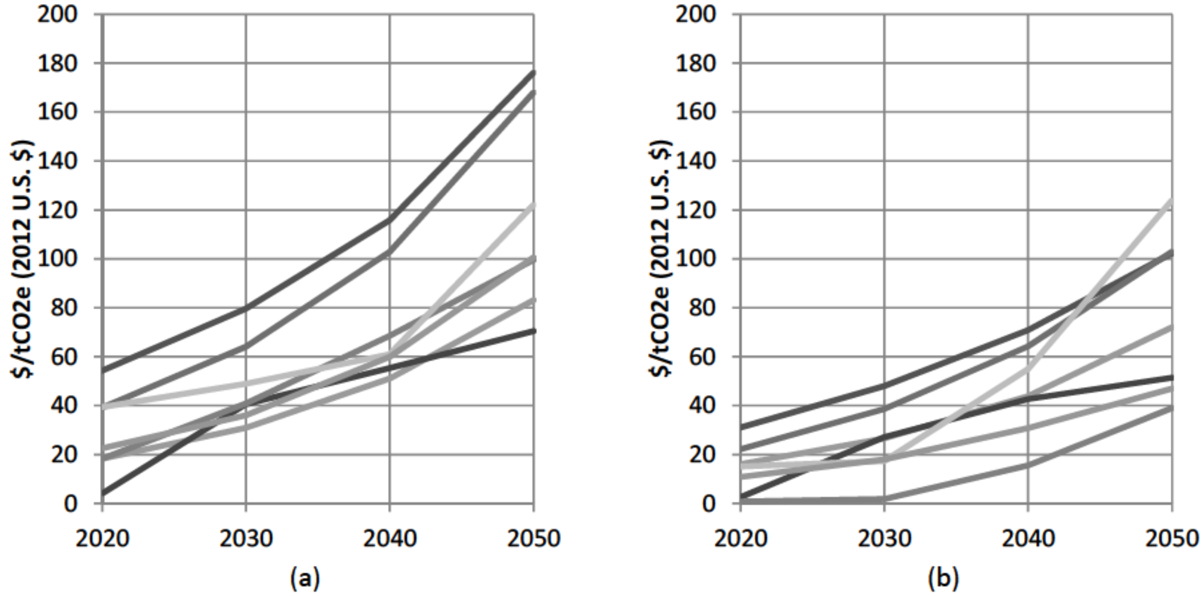
Results from the EMF 24 exercise show a range of CO_2 price trajectories depending on availability of new technologies, policy type, model baseline trajectories, and other structural characteristics of the models. One question asked by this study is of particular relevance to users of the Synapse CO_2 price forecast: which economic sectors would emissions reductions come from in an economically efficient approach to emissions mitigation? Consistent with earlier EMF analyses, the electric sector was found to be the largest contributor to CO_2 emissions reductions across all models.

Under a cap-and-trade scenario designed to reduce energy system emissions 50 percent below 2005 levels by 2050, most of the EMF 24 models reduced electric sector emissions by 75 percent by 2050. Under an 80 percent emissions reduction scenario, most of the additional emissions reductions came from other sectors. Although CO_2 prices are higher under the 80 percent scenario, most electricity customers are not paying these prices, as the electricity sector is largely decarbonized before 2050.

CO_2 prices estimated by the EMF 24 models show substantial variation. While it is difficult to distinguish the roles of model structure and model assumptions in this variation, the results present a reasonable range across which prices may fall. Under the most optimistic technology assumptions, with low-cost renewables, high levels of energy efficiency, and availability of new nuclear and CCS, CO_2 prices in 2020 fell between $10 and $40 per ton of carbon dioxide. In contrast, prices fell between $20 and $80 under the most pessimistic assumptions. Complementary policies, such as renewable portfolio standards or fuel economy standards, reduce carbon prices, as indicated in Figure 1.

Universally, the models show that substantial emissions reductions are not achievable in the absence of a carbon reduction policy. Even in the most optimistic technology scenario, the most aggressive emissions reductions from any model in the absence of a carbon policy was 0.19 percent per year, resulting in emissions 7 percent below 2005 levels in 2050.

Figure 2: Range of allowance prices from EMF 24 study under (a) 50 percent cap-and-trade policy and with (b) the addition of several complementary policies (optimistic CCS/nuclear technology assumptions). Models include USREP, US-REGEN, NewERA, GCAM, FARM, EC-IAM, and ADAGE. [50]



8. CO_2 Price Forecasts in Utility IRPs

A growing number of electric utilities include projections of the costs that will be associated with greenhouse gas emissions in their resource planning procedures. In addition to the pool of recent IRPs reviewed for this forecast, which are characterized below, Synapse has previously conducted an extensive study of resource plans dating back to 2003. None of the 15 IRPs published from 2003-2007 that we reviewed included a CO_2 price forecast. Beginning in 2008, the number of IRPs that include a CO_2 price has risen drastically. Of the 56 IRPs from 2008-2011 that we reviewed, 23 included a CO_2 price forecast. This jump in the inclusion of carbon price projections in IRPs from 2008 onwards coincided with the introduction of the Waxman-Markey bill in Congress, which sought to legislate a cap-and-trade system. As a result of this bill, the inclusion of carbon pricing sensitivities in IRPs became paramount to prudent planning beginning in 2008; a majority of the IRPs in our most recent review reflect this understanding. Of the 91 IRPs released in 2012-2013 reviewed by Synapse (referred to below as our current "sample"), 46 include a CO_2 price in at least one scenario, and 42 include a CO_2 price in their reference case scenario. This data shows that the resource plans in the latest sample, despite being produced entirely after the failure of Congress to pass comprehensive climate legislation, includes a similar fraction of IRPs with a CO_2 price forecast as the 2008-2011 sample, when major climate bills were under consideration.

How well does our sample represent utility planning across the United States? A total of 3,412 utilities operated in the United States in 2012.[48] In terms of generation, the top 5 percent—170 utilities—accounted for 77 percent of total U.S. generation in 2012. Our sample includes IRPs from 29 utilities within this largest 5 percent. Of those 29, 25 utilities have IRPs with non-zero CO_2 prices. This means that almost all of the IRPs we reviewed from the largest utilities in the country include a non-zero CO_2 price in their planning process.

Overall, our entire sample of 91 2012-2013 IRPs comes from utilities that represent 20 percent of total sales nationally, where:

- Those IRPs with non-zero CO_2 price forecasts in any scenario come from utilities that represent more than 18 percent of total U.S. sales,
- Those IRPs with no consideration of CO_2 prices come from utilities that represent less than 2 percent of total U.S. sales.[49]

Additional statistics describing these forecasts are provided in Table 2. The IRPs in our sample represent roughly a fifth of total U.S. generating capacity and CO_2 emissions. Given the substantial number of utilities that keep large portions of their IRPs confidential, as well as utilities who do not complete IRPs (discussed below), we are confident this is a reasonable sample size.

Table 2: IRP Sample Size Statistics

Utility Summary	Number of Utilities	Generation (TWh)	Sales (TWh)	Capacity (GW)	Customers (Million)	CO_2 Emissions (million tons)
US Totals - from EIA 860 data	3,412	4,043	3,695	1,168	155	2,209
All IRPs Analyzed						
All Years	162	-	-	-	-	-
2012 - 2013 Sample	91	-	-	-	-	-
With CO_2 Prices (2012 - 2013 Sample)	46	-	-	-	-	-
IRPs Matched to EIA 860 data						
2012 - 2013 Sample	64	774	756	205	29	495
% of US Totals	*2%*	*19%*	*20%*	*18%*	*18%*	*22%*
With CO_2 Prices (2012 - 2013 Sample)	40	688	672	175	25	401
% of US Totals	*1%*	*17%*	*18%*	*15%*	*16%*	*18%*

Source: EIA Form 860, 2012 (Released Oct. 10, 2013).

[48] EIA Form 860, 2012 (Released Oct. 10, 2013).

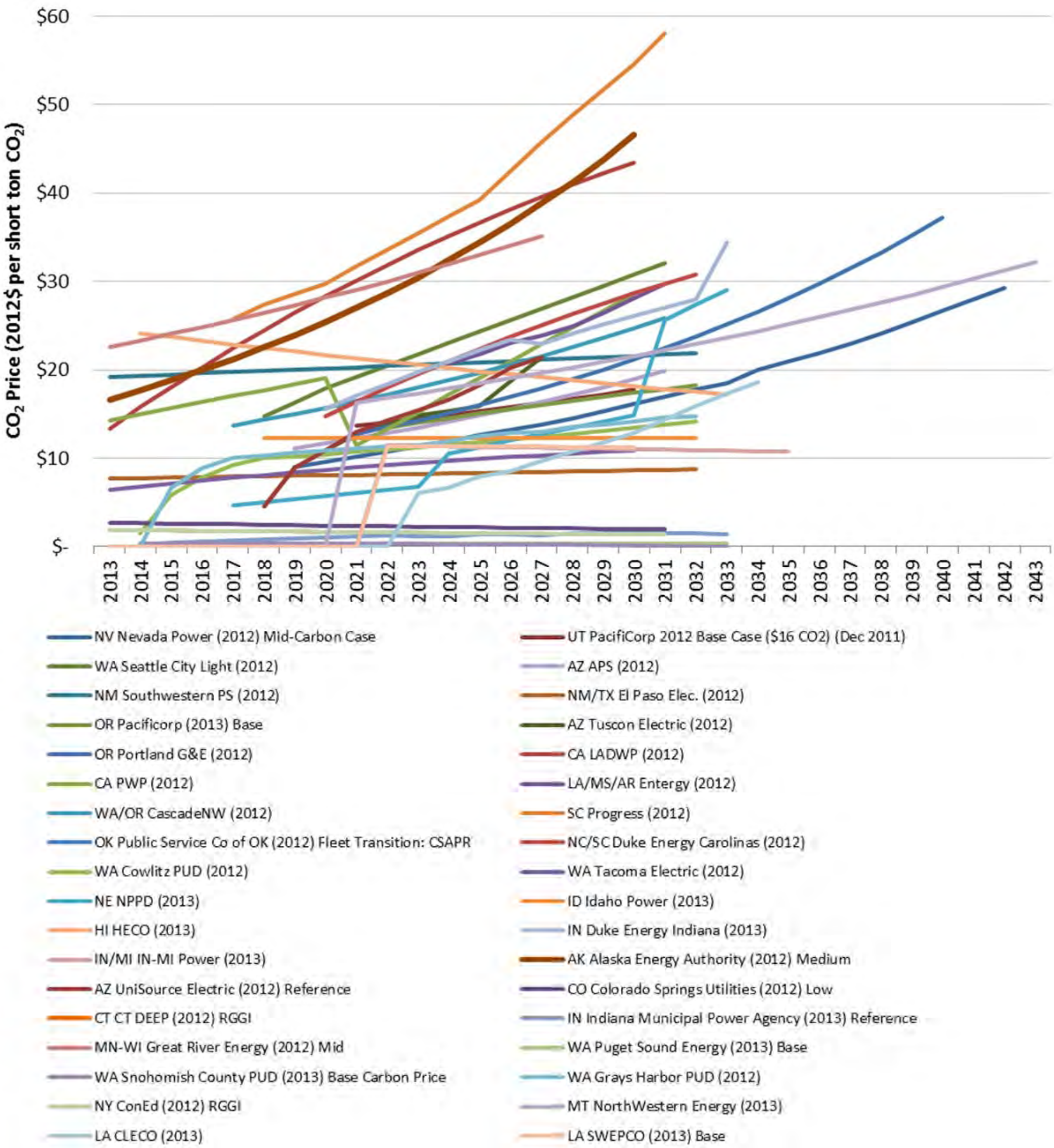
[49] Two forecasts in Figure 3 are not included in the sales total: Alaska Energy Authority and Connecticut Department of Energy and Environmental Protection cover multiple utilities in their respective states, and could not be matched to just one.

Not all utilities produce IRPs. In fact, 11 states have no filing requirements for long-term planning, while 10 other states require long-term plans, but not IRPs.[50] While long-term planning is an important part of the procurement process in regions with wholesale energy markets, the traditional utility-centric integrated resource plan is less common in competitive markets. As a result, regions with wholesale markets are not well represented in our sample.

Figure 3 below displays non-zero, non-confidential reference case CO_2 price forecasts from 36 utility IRPs over the period of 2013-2043. Although we refer to 42 non-zero reference case forecasts above, six reference case forecasts with non-zero CO_2 prices are excluded from this chart: there are three instances of the same company operating in multiple states producing multiple IRPs but using the same CO_2 forecast; two are non-zero but confidential; and one forecasts a non-zero price beginning after the company's IRP study period ends in 2023 and is thus not provided in the IRP. On average, the non-zero reference case forecasts in Figure 3 begin forecasting a price for CO_2 in 2017.

[50] See: Wilson, R. and B. Biewald. *Best Practices in Electric Utility Integrated Resource Planning*. June 1, 2013. Synapse Energy Economics. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2013-06.RAP.Best-Practices-in-IRP.13-038.pdf.

Figure 3: Utility Non-zero and Non-confidential Reference Case Forecasts from 2012 and 2013[51]



Note: The CO_2 forecasts from CLECO and SWEPCO are provided in publicly available planning assumption documents in preparation for IRPs to be released at a later date.

[51] Six non-zero, non-confidential reference case forecasts are excluded, discussed further on page 22.

Four of the utility forecasts displayed in Figure 3 are particularly low in the context of the other forecasts. Two IRPs from the Northeast—Commonwealth Edison of New York and the Connecticut Department of Energy and Environmental Protection—base their reference case forecasts on RGGI prices before the recent RGGI revisions discussed in Section 5, resulting in prices just under $2 per short ton. Two other IRPs—Puget Sound Energy and Snohomish County PUD—use a Washington State mandated CO_2 price of $0.32 per short ton for their base case analyses.

The four utilities that assume a $0 CO_2 price in their reference cases also consider several additional non-zero scenarios. These are provided in Appendix A.

Table 3 summarizes the range of CO_2 prices forecasted for 2020 and 2030 from the 36 utility IRPs. Not all forecasts start by 2020, and those that do are generally below $20 per ton. Of the utilities with a non-zero CO_2 price, all but five assume a price in 2030; some of the missing five have planning periods that end before 2030.

Table 3: Number of Utility CO_2 Forecasts from 2012-2013 in several price ranges in 2020 and 2030

	2020	2030
<$10	10	5
$10 - $20	11	14
$20 - $30	6	8
$30 - $40	0	1
>=$40	0	3

9. Overview of the Evidence for a Future CO_2 Price

Our CO_2 price forecasts are developed based on the data sources and information presented above and reflect a reasonable range of expectations regarding future efforts to limit greenhouse gas emissions. The following items have guided the development of the Synapse forecasts:

- **Regulatory measures limiting CO_2 emissions from power plants will be implemented in the near term.** The EPA is required to propose emissions standards for existing power plants under Section 111(d) of the Clean Air Act by June 2014. Standards for new power plants were proposed in September 2013. These actions represent an effective price that will affect utility planning and operational decisions.

- **State and regional action limiting CO_2 is ongoing and growing more stringent.** In the Northeast, the RGGI CO_2 cap has been tightened, resulting in higher CO_2 prices for electric generators in the region. California's Cap-and-Trade Program, which represents an even larger carbon market than RGGI, has held many successful allowance auctions, and has been successfully defended against numerous legal challenges.

- **A price for CO_2 is already being factored into federal rulemakings.** The federal government has demonstrated a commitment to considering the benefits of CO_2 abatement in rulemakings such as fuel economy and appliance standards.

- **Ongoing analysis of emissions caps suggests a wide range of possible prices.** Important factors include the stringency of any future climate policy, the existence of complementary policies, technology availability, and how quickly old capital stock can be phased out in favor of new technologies.

- **Electric suppliers continue to account for the opportunity cost of CO_2 abatement in their resource planning.** Prudent planning requires utilities to consider adequately the potential for future policies. The range of carbon prices reported in Section 8 indicates that many utilities believe that by 2020 there will likely be significant economic pressure towards low-carbon electric generation.

10. SYNAPSE 2013 CO_2 PRICE FORECAST

Based on analyses of the sources described in our 2013 Carbon Dioxide Price Forecast report from November, and relying on our own expert judgment, Synapse has developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. We have not reevaluated these forecasts based on the updated information on federal regulatory measures limiting CO_2, state climate action, and utility CO_2 pricing presented in this report. Figure 4 and Table 4 show the Synapse forecasts over this period.

Figure 4: Synapse 2013 CO_2 Price Trajectories

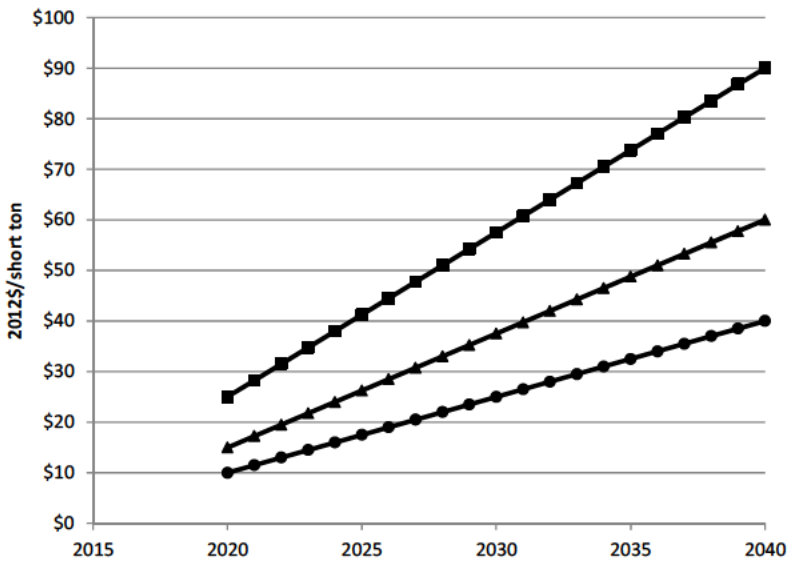


Table 4: Synapse 2013 CO_2 Price Projections (2012 dollars per short ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$10.00	$15.00	$25.00
2021	$11.50	$17.25	$28.25
2022	$13.00	$19.50	$31.50
2023	$14.50	$21.75	$34.75
2024	$16.00	$24.00	$38.00
2025	$17.50	$26.25	$41.25
2026	$19.00	$28.50	$44.50
2027	$20.50	$30.75	$47.75
2028	$22.00	$33.00	$51.00
2029	$23.50	$35.25	$54.25
2030	$25.00	$37.50	$57.50
2031	$26.50	$39.75	$60.75
2032	$28.00	$42.00	$64.00
2033	$29.50	$44.25	$67.25
2034	$31.00	$46.50	$70.50
2035	$32.50	$48.75	$73.75
2036	$34.00	$51.00	$77.00
2037	$35.50	$53.25	$80.25
2038	$37.00	$55.50	$83.50
2039	$38.50	$57.75	$86.75
2040	$40.00	$60.00	$90.00
Levelized 2020-2040	$22.36	$33.54	$51.79

In these forecasts, state and regional policies, together with federal regulatory measures, place economic pressure on CO_2-emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. These pressures are followed later by a broader federal policy, such as cap and trade. In any state other than the RGGI region and California, we assume a zero carbon price through 2019; beginning in 2020, we expect that federal regulatory measures will put economic pressure on carbon-emitting power plants throughout the United States. All annual allowance prices and levelized values are reported in 2012 dollars per short ton of carbon dioxide.

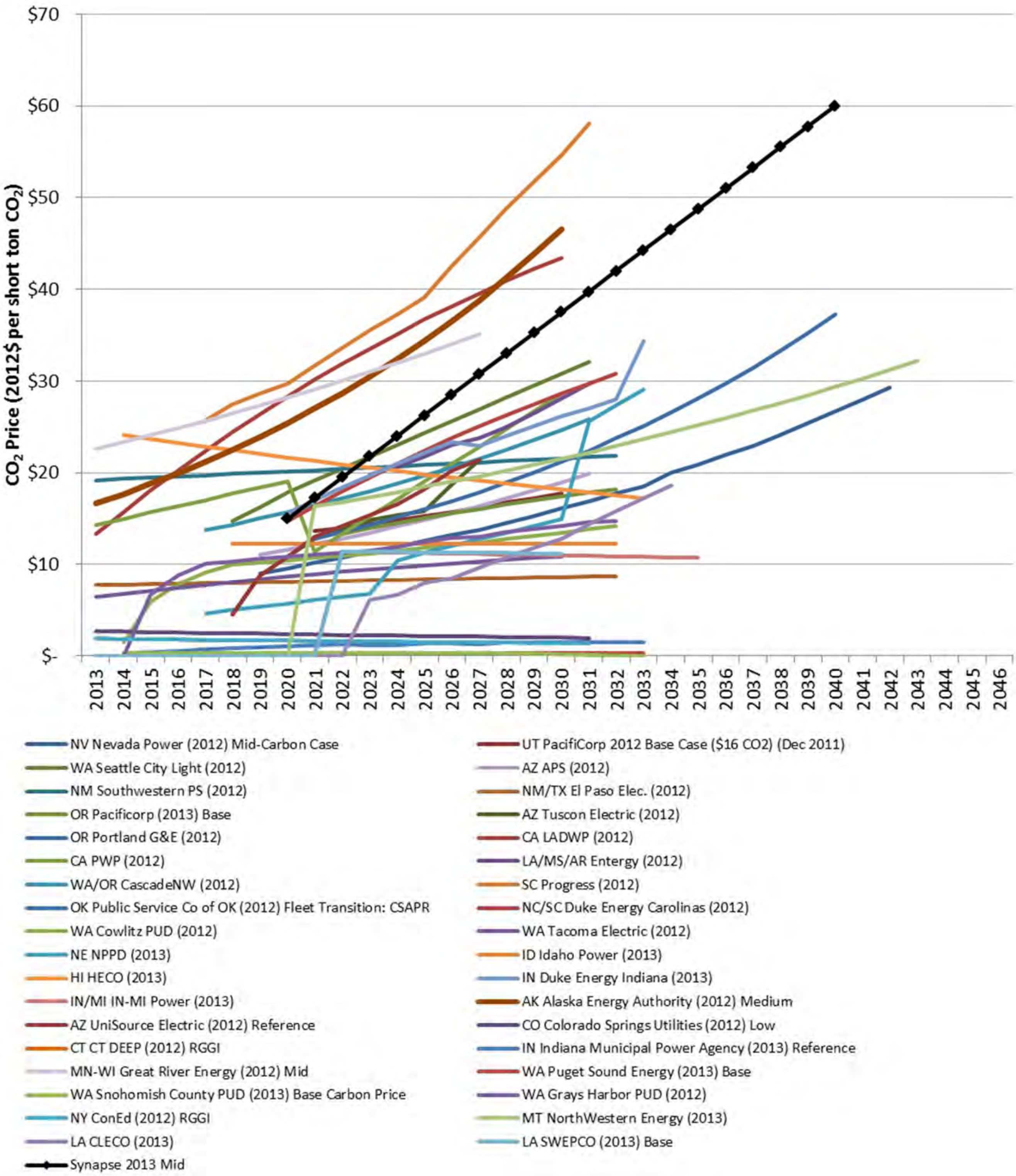
- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect

of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

These price trajectories are designed for planning purposes, so that a reasonable range of emissions costs can be used to investigate the likely costs of alternative resource plans. We expect an actual CO_2 price to fall somewhere between the low and high estimates throughout the forecast period.

In Figure 5, the Synapse Mid forecast is shown in comparison to the reference case utility forecasts presented earlier. See Appendix A for comparisons to utilities' Low and High case forecasts.

Figure 5: Synapse Mid Forecast Compared to Recent Utility Reference Case Forecasts



In Figure 6, the Synapse forecasts are compared to the carbon price used in federal rulemaking. While the federal price starts out higher in 2020, the Synapse Mid forecast approaches this value at the end of the projected period.

Figure 7 compares the Synapse forecasts for 2020 to several of the sources identified in this report: the carbon price used in federal rulemakings, EMF 24 study results, and recent utility forecasts. The high and low ends of these sources span a wide range, but the central (mean) values show less variation. The Federal Carbon Price for Rulemakings shows a particularly large spread resulting from different choices in the assumed discount rate. Similarly, some EMF models show a zero carbon price in 2020, implying the country can get to 17 percent below 2020 based on technology improvement and other existing policies. Other models have substantially higher prices, perhaps resulting from more growth in energy consumption in the reference (no policy) case.

Figure 6: Synapse Forecast Compared to Carbon Price Used in Federal Rulemakings

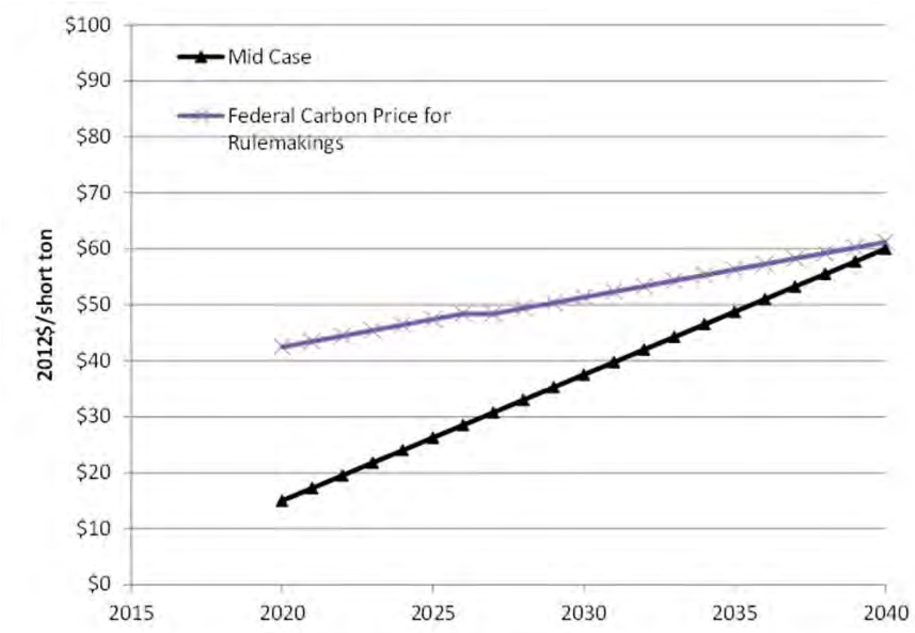
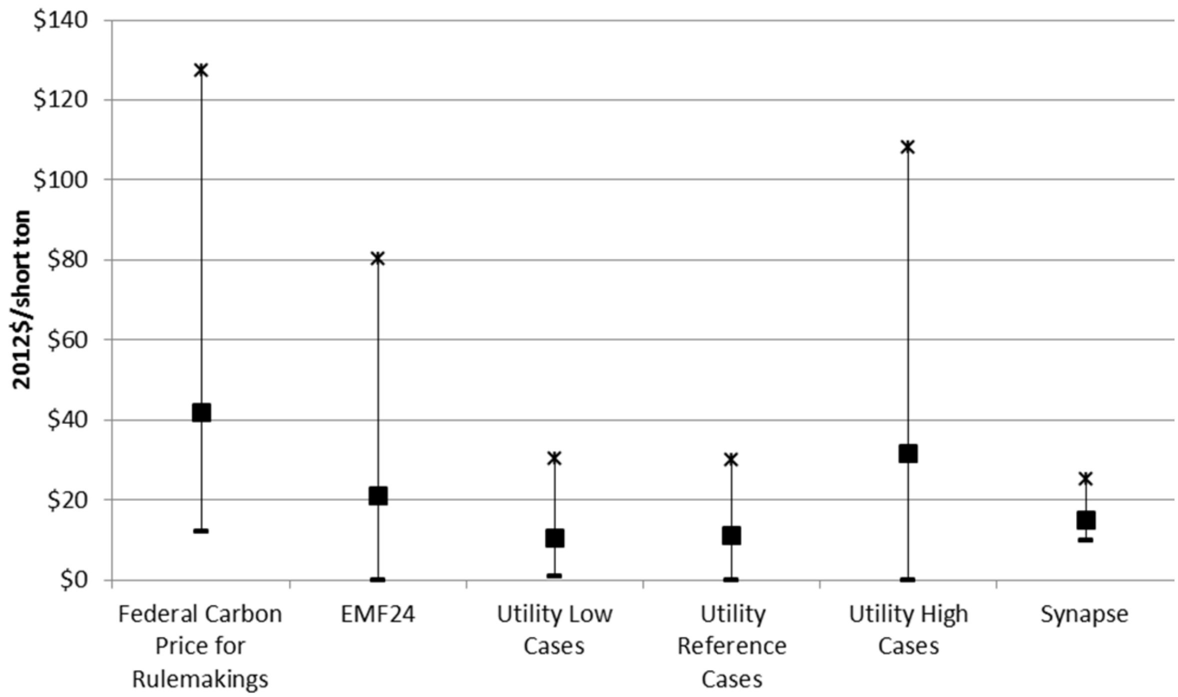


Figure 7: Synapse CO_2 Forecasts for 2020 Compared to Other Sources



11. APPENDIX A: SYNAPSE FORECAST COMPARED TO UTILITY FORECASTS

Figure 8: Synapse CO2 Price Forecast Compared to Recent Utility Low-case Forecasts

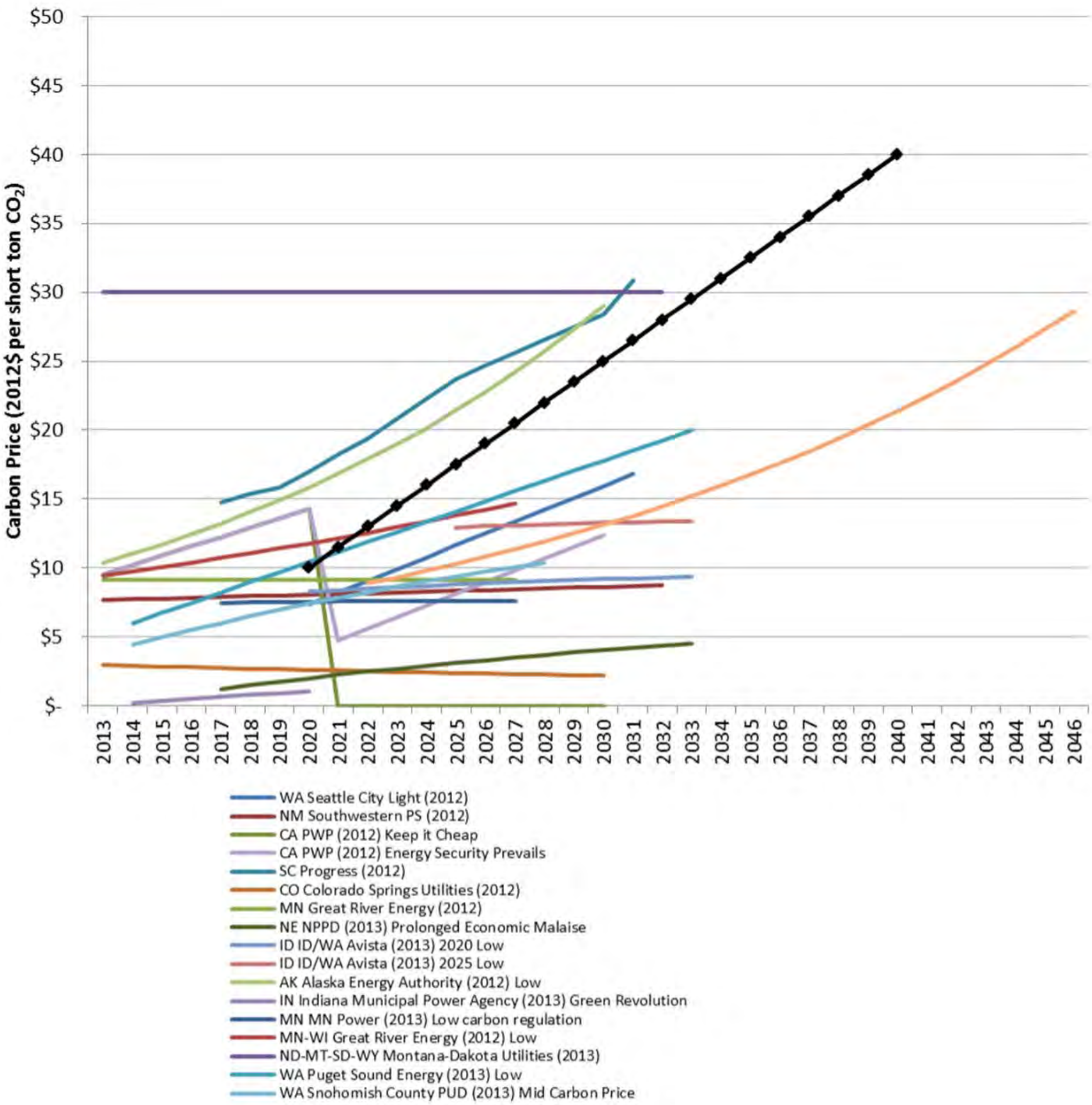


Figure 9: Synapse CO2 Price Forecast Compared to Recent Utility High-case Forecasts

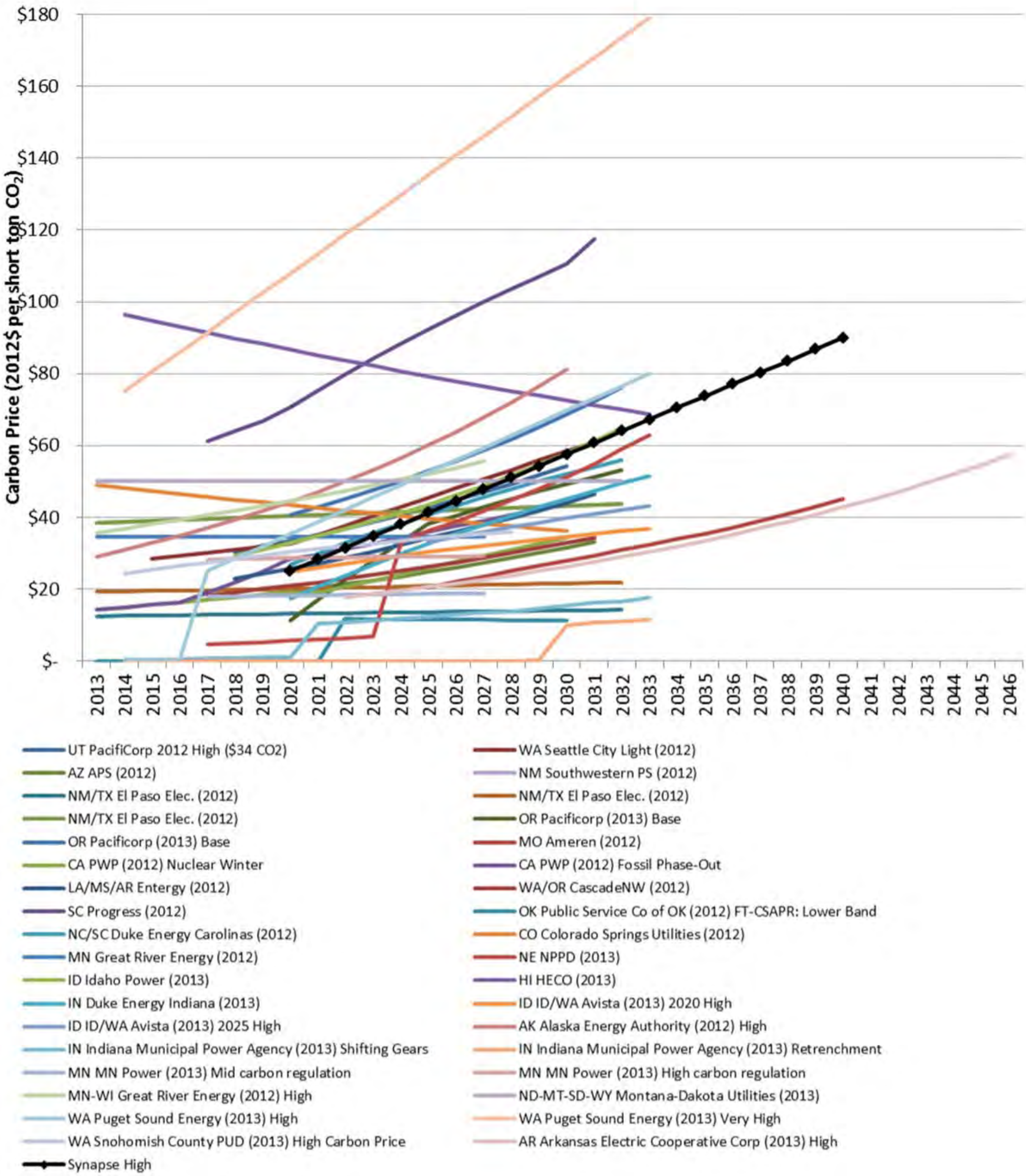
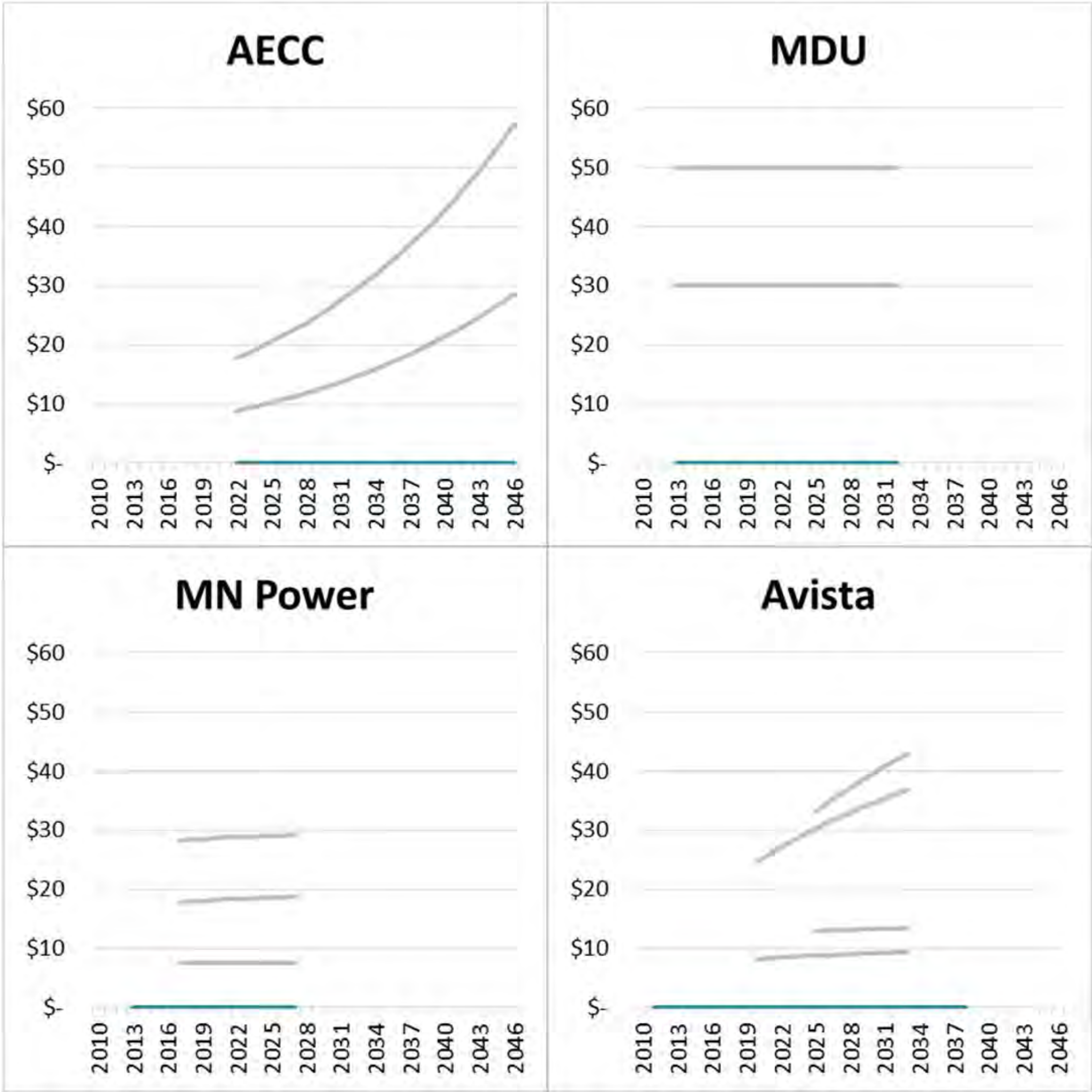


Figure 10: Range of CO_2 Price Scenarios for Utilities with \$0 Reference Cases (2012\$/short ton)



Note: Reference forecasts are presented in blue. All other sensitivities are in grey.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Direct Testimony of Sarah E. Jackson* – either a Highly Confidential or a Redacted version - was served via electronic transmission upon the parties this 26th day of September, 2014.

/s/Christopher J. Allwein
Christopher J. Allwein

SERVICE LIST

Steven.beeler@puc.state.oh.us
Thomas.lindgren@puc.state.oh.us
Ryan.orourke@puc.state.oh.us
dboehm@BKLlawfirm.com
mkurtz@BKLlawfirm.com
jkylercohn@BKLlawfirm.com
Schmidt@sppgrp.com
Judi.sobecki@aes.com
Bojko@carpenterlipps.com
allison@carpenterlipps.com
cmooney@ohiopartners.org
stnourse@aep.com
mjsatterwhite@aep.com
yalami@aep.com
asonderman@keglerbrown.com
mkimbrough@keglerbrown.com
hussey@carpenterlipps.com
mhpetricoff@vorys.com
mjsettineri@vorys.com
glpetrucci@vorys.com
dmason@ralaw.com
mtraven@ralaw.com
rchamberlain@okenergylaw.com
dstinson@bricker.com
dborchers@bricker.com

Amy.Spiller@duke-energy.com
Elizabeth.watts@duke-energy.com
Rocco.dascenzo@duke-energy.com
Jeanne.Kingery@duke-energy.com
haydenm@firstenergycorp.com
jmcdermott@firstenergycorp.com
scasto@firstenergycorp.com
joliker@igsenergy.com
joseph.clark@directenergy.com
sam@mwncmh.com
fdarr@mwncmh.com
mpritchard@mwncmh.com
tdougherty@theOEC.org
dhart@douglasehart.com
cloucas@ohiopartners.org
gpoulos@enernoc.com
swilliams@nrdc.org
tobrien@bricker.com
ghull@eckertseamans.com
jvickers@elpc.org
Maureen.grady@occ.ohio.gov
berger@occ.state.oh.us
serio@occ.state.oh.us

Attorney Examiner:

Christine.pirik@puc.state.oh.us
Nicholas.walstra@puc.state.oh.us