Chapter 2 - Appendix A

Subjective Probability Elicitation Details[1]

Following the initial meeting, Ameren Missouri's management identified several in-house experts to provide the probability distributions for each critical uncertain variable. For the electricity demand growth variable in particular, CRA suggested that it might be useful to have experts with knowledge of some of the key drivers of electricity demand growth, including GDP, consumer behavior/energy efficiency opportunities, and on-grid load growth (which is a function of distributed generation). With this background, Ameren Missouri identified the following experts[2]:

- Load growth – Rick Voytas, Manager of Energy Efficiency and Demand Response, and Ajay Arora, Director of Corporate Planning;
- Carbon policy – Dan Cole, President and CEO of Ameren Services, and Joe Power, Vice President of Federal, Legal, and Regulatory Affairs; and
- Natural gas prices – Jim Massmann, Manager of Gas Supply, and Shawn Schukar, Vice President of Strategic Initiatives.[3]

It was also important to complete probability elicitations prior to an Executive Leadership Team (ELT) meeting in January 2009, at which updates to strategic planning were to be discussed. To minimize any potential increase in anchoring or motivational biases that might arise out of such discussions, CRA scheduled in-person probability elicitations with ELT participants (Messrs. Schukar, Cole, Power and Arora) in the two weeks before the ELT retreat.

Load Growth[4]

Subject matter experts on this item, Ajay Arora and Rick Voytas, decided to take slightly different approaches during the course of their elicitation sessions.

Mr. Voytas chose to directly assess future load growth outcomes, encompassing his overall sense of a variety of opposing forces and trends. Before the actual elicitation, a list was created of all the forces of concern in his mind, which was placed before him and referred to throughout the elicitation portion of the interview.

He listed the following reasons for why load growth could be higher than the historical average (listed here in order of his opinion of their relative likelihood of having

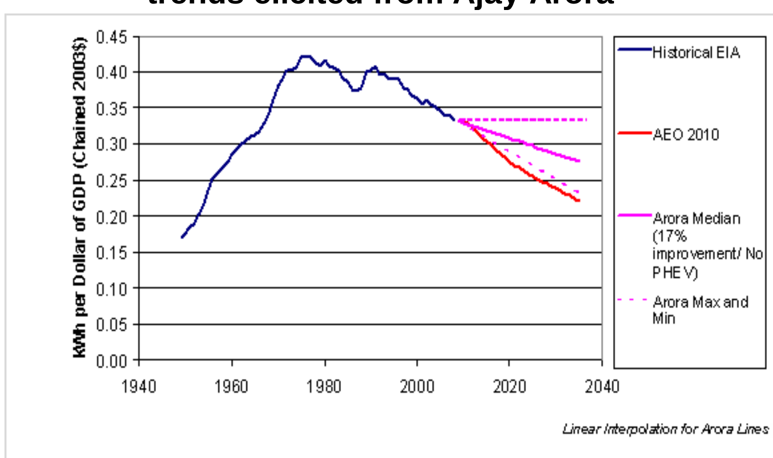
[1] EO-2007-0409 – Stipulation and Agreement #34; EO-2007-0409 – Stipulation and Agreement #35
[2] EO-2007-0409 – Stipulation and Agreement #32; EO-2007-0409 – Stipulation and Agreement #38(A)
[3] 4 CSR 240-22.040(8)(A)1.
[4] 4 CSR 240-22.030(8)(D)4.

significant effect): increases in miscellaneous load from consumer electronics, aging of population leading to more air conditioning/heating to maintain comfort, smaller technology efficiency gains than historical averages, young population using more consumer electronics, above-average GDP growth, adoption of plug-in hybrid electric vehicles (PHEV), and electrification to support economy-wide de-carbonization goals.

He also listed the following reasons that load growth could be lower than the historical average (also listed in order of his views on their relative likelihood of having significant effect): improvements in commercial/industrial lighting technology, increasing electricity rates due to pending large capital investment needs for infrastructure, improvements in efficiency of motors, below-average GDP growth, and greater consumer awareness of electricity use with the implementation of smart grid technologies. From this foundation, CRA then elicited the 2010 through 2040 average rate of load growth.

Mr. Arora, on the other hand, preferred producing probability distributions for GDP growth and electricity intensity trends (measured in terms of kWh per GDP dollar) separately. CRA began by eliciting GDP growth over the next 30 years (annual average). Mr. Arora could not envision long-term average GDP growth below 1.0% or above 4.0%, and identified a median expected long-term growth rate of 2.5%. For electricity intensity trends, he focused first on a world without significant penetration of PHEVs.

Figure 2.A.1 US electricity intensity trends elicited from Ajay Arora



CRA provided a chart of historical U.S. electricity intensity trends (see blue line in Figure 2.A.1). As shown by the three pink lines also shown in Figure 2.A.1, Mr. Arora assigned a maximum improvement over the next 30 years of 30%, a median improvement of 17%, and a minimum improvement of 0%. (The red line in Figure 2.A.1 compares Mr. Arora's range to the estimate in the 2010 Annual Energy Outlook published by the US Energy Information Administration (EIA). Mr. Arora's views appear to be less optimistic than those of EIA.)

Both experts separated trends in consumption of electricity from trends on whether that electricity would be supplied on or off grid. Two countervailing forces in this arena are PHEV (which would increase on-grid electricity demand) and distributed generation advancements (which would decrease on-grid electricity demand). To the former, both Mr. Arora and Mr. Voytas assigned a fairly substantial probability (40% and 55%, respectively) to PHEVs becoming the dominant vehicle of choice (defined as PHEVs constituting more than half of new vehicle purchases by 2030).

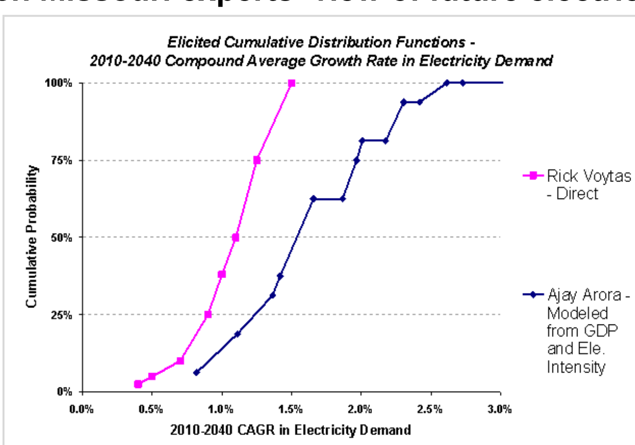
After the interviews, CRA calculated that this event might increase the foregoing projected loads by 5% to 8%, equivalent to a probability-weighted load increase in 2030 of less than 4% (and much less in earlier years). Regarding distributed generation, the experts expressed the opinions that the maximum achievable load reductions by 2040 would be no more than 5 to 10%.

Since the effects of PHEVs and of distributed generation on load growth are essentially offsetting, and are quite small, and occur only towards the later part of the analysis time horizon, it was agreed that the added effort of incorporating these two effects into the elicited probability distributions would not substantially alter resource plan evaluation.

Thus, the final load growth probability distributions were based on the load growth probabilities developed without consideration of either PHEVs or distributed generation. The above discussion provides readers with information on what the experts' views on PHEV and distributed generation outcomes.

Figure 2.A.2 presents the cumulative distribution functions (CDFs) of the 2010 through 2040 compound average growth rate (CAGR) in U.S. electricity demand, as elicited from each expert. To understand how to draw inferences from these CDF curves, consider the pink square marker of Mr. Voytas' CDF that lies on the 50% probability gridline. This indicates that Mr. Voytas judged that there was a 50% chance that the 2010 through 2040 average growth rate of U.S. electricity demand would be less than or equal to 1.1%, with a 90% confidence interval of (0.5%, 1.5%). Mr. Voytas expressed more conservative views of load growth than Mr. Arora, whose 90% confidence interval was (0.8%, 2.5%).

Figure 2.A.2 Ameren Missouri experts' view of future electricity demand growth



After discussion of the differences, the two experts remained comfortable with their original statements, while acknowledging the reasons they came to different overall views. It was therefore agreed to produce a linearly-weighted distribution on load growth giving equal weight to their separate views on probabilities.

The resulting combined distribution is summarized in the two dark blue lines in Figure 2.A.3 as the load over time (relative to 2010 load) that is associated with two outcomes each of 50% likelihood. For purposes of context, the figure also shows the "50%/50%" load paths of each expert's views in isolation (pink lines for Mr. Voytas's individual views, and yellow lines for Mr. Arora's views).

Figure 2.A.3 Illustrative Load Projections

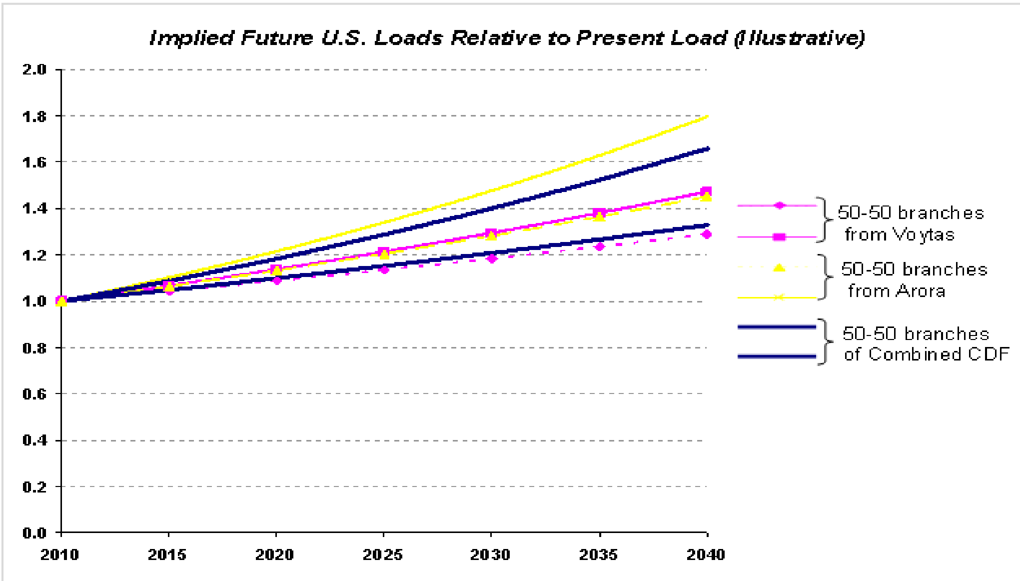
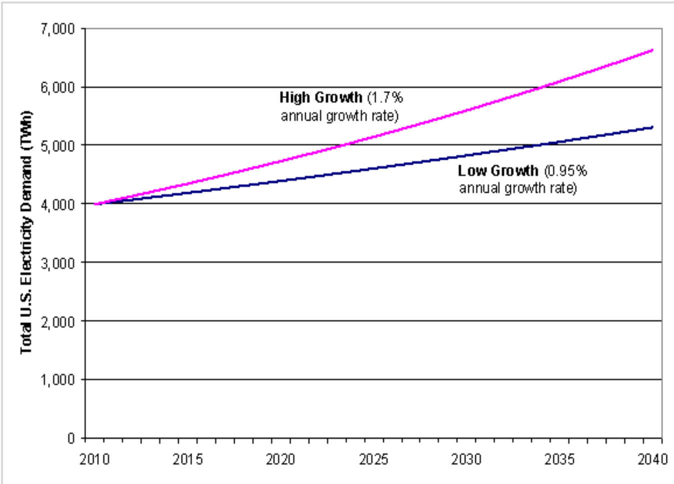


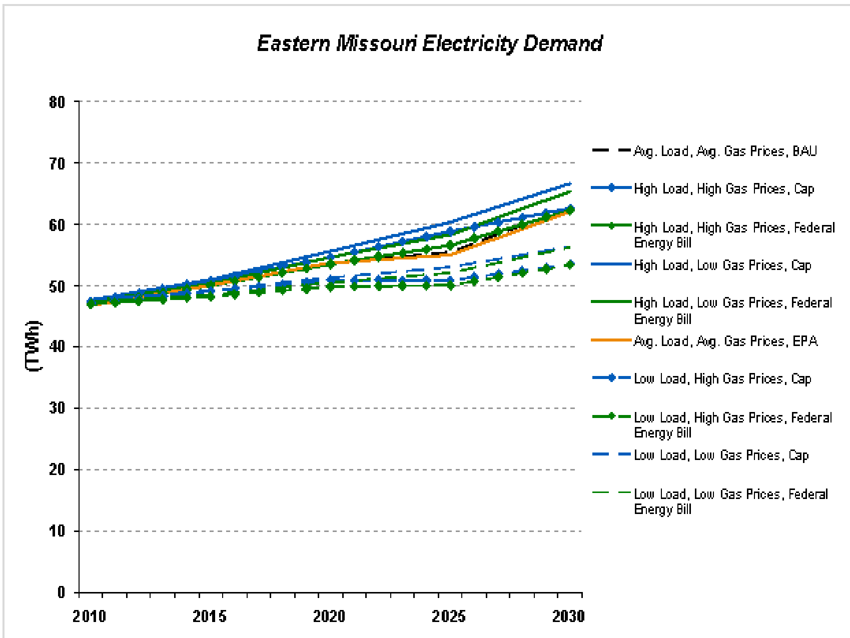
Figure 2.A.4 Baseline Load Projections



The actual input to the MRN-NEEM model is the load over time. Figure 2.A.4 shows the total U.S. baseline electricity demands that are the result of the 50%/50% high and low load growth rates of the final probability tree. These are the input as the business-as-usual loads, but final load in each scenario may differ because of the added effects of the scenario itself.

For example, if a high carbon price is imposed, electricity rates are increased, with resulting reductions in demand relative to the business-as-usual forecast for that case. Thus, the final loads for each scenario vary depending on the other variables in the tree, such as the effect of the carbon price and of the natural gas price. MRN-NEEM's Eastern Missouri load forecasts in each scenario are shown in Figure 2.A.5. These scenarios combine with the other elicited variable outcomes to result in the 10 scenario combinations after tree trimming occurs, with trimming discussed later in this section.

Figure 2.A.5 Eastern Missouri Electricity Demand, MRN-NEEM Scenarios (TWh)



Carbon Policy[5]

Carbon policy constitutes one of the most influential uncertain factors affecting the complexion of potential resource plans. The abatement proposals that have circulated in Congress in recent years vary greatly in form, coverage, and stringency. With varying degrees of mitigation come varying estimates of the costs to vital components of the U.S. economy, including the electricity generation sector. Ameren Missouri incorporated CO_2 policy outcomes as one of the variables comprising the IRP probability tree.

Legislation presiding over three-pollutant (SO_2, NO_X, and Hg) emissions is in a state of flux, with the future of SO_2, NO_X, and Hg emissions caps under the previous Clear Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) remanded. Regarding CAIR, the U.S. Court of Appeals for the D.C. Circuit summarily vacated and remanded CAIR in its entirety in July of 2008.

[5] 4 CSR 240-22.040(2)(B)1-4

The EPA petitioned vigorously for a rehearing, arguing that an outright vacatur would not only delay much needed reductions in hazardous air pollutants, but also imperil compliance with other air quality programs that relied upon CAIR-induced emission reductions. Particularly, EPA argued that a stay on, as opposed to a vacatur of, CAIR would provide for a smoother regulatory transition. In December of 2008, the D.C. Circuit suspended the vacatur but upheld the remand of CAIR such that CAIR is currently the law. In the absence of any specific alternative at the time of modeling, the CAIR rule was simulated in the MRN-NEEM analyses. On July 6, 2010 (after the MRN-NEEM runs had been completed), EPA released a proposed rule, the Clean Air Transport Rule (CATR), for comment. This proposed rule is more stringent than CAIR, and is likely to become the subject of new litigation, if it is not first replaced by a 3-P Bill such as Sen. Carper's.

Regarding mercury abatement, the D.C. Circuit vacated CAMR in February of 2008, ruling that the EPA did not have the legal authority to de-list coal- and oil-fired electricity generating units from Section 112(c) of the Clean Air Act (CAA). The EPA is planning to replace the CAMR rule with a MACT standard for mercury and other hazardous air pollution emissions from power plants and is required by a consent decree to propose regulations in March 2011 and finalize regulations in November 2011. The CAA compliance timeline is 3 years, so the earliest implementation date would be late 2014. Litigation is likely for this soon to be released rule.

In this period of uncertainty, Senator Carper has announced that he intends to release a three-pollutant (3-P) bill that will contain a 90% MACT requirement. Likelihood of passage is highly uncertain. Given this political backdrop, this analysis drops the CAMR cap-and-trade approach, and instead institutes a two-phase MACT requirement for all coal-burning electricity generating units. In 2015 and 2020, coal power plants face mandatory mercury emission reduction requirements of 60% and 90%, respectively.

Notwithstanding the considerable uncertainty in the form, if any, of three-pollutant (3-P) legislation over the next twenty years, their associated market-level impacts on relevant IRP outcomes will be negligible, especially in the shadow of the climate change debate. Preliminary modeling results indicate that wide variations in 3-P prices have very little impact on IRP-relevant inputs and outputs. This is in stark contrast to the case outlined above for CO_2 policy.

In fact, previous CRA experience has repeatedly demonstrated that 3-P prices are actually more sensitive to carbon policy changes than to further modifications to their own caps, provided that legally-binding caps exist in the first place. Therefore, changes to emissions policy costs outside of CO_2 are not judged to satisfy the criteria in this section.

The three carbon policy scenarios (Cap-and-Trade, Federal Energy Bill, and Moderate EPA Regulation), by their very existence, represent more stringent forms of CO2 emission control than those currently presiding in the U.S, and thus satisfy the requirement to specify at least two levels of mitigation that are more stringent than existing requirments.

The two designated subject matter experts for carbon policy outcomes, Joe Power and Dan Cole, had consistent views about the range of possible types of carbon policy outcomes and their relative likelihoods. In brief, the likelihood of a carbon cap-and-trade policy was deemed to be less likely than alternative carbon policies that would not involve any price on carbon emissions.

The content experts expressed as much uncertainty around the nature of potential non-market, regulatory approaches as around the expected CO_2 price levels given a cap-and-trade program were in place. Thus, CRA and Ameren Missouri decided that the best approach for the carbon policy tree branches was to capture policy outcomes that were different in a qualitative manner, rather than to use branches that solely captured the uncertainty in what the carbon price or carbon cap level would be.

Mssrs. Power and Cole identified four qualitatively different possible policy drivers:

1. An economy-wide greenhouse gas cap-and-trade program with the mean CO_2 prices shown in Table 2.A.1 below.

Table 2.A.1 Elicited CO2 Prices

Year	CO2 Price (2010$/metric ton)
2015	$7.50
2020	$17.50
2025	$21.50
2030	$29.25
2035	$37.00
2040	$47.22

2. "Federal Energy Bill" measures aimed at reducing carbon emissions in many parts of the economy, but with no CO_2 cap. The components of such an approach that the experts thought might affect the electricity sector were:

- A national renewable electricity standard (RES)
    - Percentage requirements: 9.5% in 2015, 20% in 2020, 40% in 2040
    - The following exemptions to the baseline amount of electricity against which the above percentages are applied:
        - Small retailers with less than 4 million MWh in annual sales

        - Existing hydroelectric power plants
        - New nuclear power plants
        - 90% of sales from new IGCC with carbon capture and storage (CCS)
    - Alternate compliance payment of $25/MWh (in 2009$)
    - No energy efficiency carve-outs

- New Capacity Incentives/Subsidies – incentives to help bring in new nuclear, coal with CCS, and central-station solar thermal power plants. To flesh out these concepts, MRN-NEEM was set up to assume the outcomes of such subsidy programs would match the following schedules.
    - 15 GW of nuclear by 2020
    - 50 GW total of coal with CCS by 2035 (5 GW in 2020, 10 GW in 2025, 15 GW in 2030, and 20 GW in 2035)
    - 35 GW total of solar thermal by 2035, per Table 2.A.2 below

Table 2.A.2 Forced Solar Thermal Capacity Additions

GW	2025	2035
S. Cal	3	4
N. Cal	3	4
AZ/NM	3	4
TX	2	4
KS	2	2
OK	2	2

The model determined where the nuclear and CCS facilities would be built (i.e., in the least cost/most valuable locations), while the solar thermal plants were assumed to be built in California, Arizona/New Mexico, Texas, Kansas and Oklahoma.

- Energy Efficiency Provisions –including yet more provisions such as those included in the Energy Independence & Security Act of 2007 (EISA), which included corporate average fuel economy (CAFE) standards, tighter standards for lighting and appliances, and energy conservation in buildings. To simulate the effect of such measures, the Energy Bill cases were forced to achieve the U.S.-wide efficiency targets set forth in Table 2.A.3.

Table 2.A.3 Reductions in Consumption

Year	% Reduction in Electricity Demand	% Reduction in Household/Commercial Natural Gas Use
2015	1.5%	1.5%
2020	2.5%	2.5%
2025	4.0%	4.0%
2030	4.5%	4.5%
2035-2040	5.0%	5.0%

- "Cash for clunkers" in the electric sector – an unspecified program that will lead to the retirements of existing coal units. For modeling purposes, we let the model identify the most cost-effective way to achieve cumulative retirements of 10 GW by 2015, 30 GW by 2020 and 60 GW by 2025. These retirements were not forced in any regional manner. As a result, certain regions of the country could be more affected by this policy than others, to the extent that they have a larger proportion of the coal units that would be among the least cost to retire early.

- No new coal is allowed to be built without CCS.

3. EPA regulations with little legislative intervention.

- No new coal is allowed to be built without CCS.

4. Business-as-usual (BAU) – a case that represents the continuation of the present world, with no major greenhouse gas policy measures. As such, new uncontrolled coal is allowed to be built.

Both experts shared a similar sense of the timeline and circumstances under which a greenhouse gas cap-and-trade program would be implemented. When considering the probability of cap-and-trade versus other carbon policy directions, each expert evaluated cap-and-trade's prospects before and after 2015 separately.

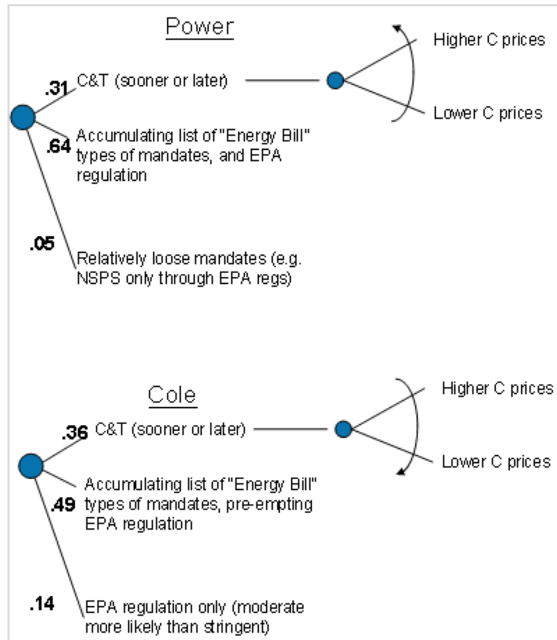
Mr. Power assigned a 10 to 15% probability to cap-and-trade passing before 2015, moreover indicating that the most likely window closes at the end of 2010. After 2015, Mr. Power suggested that cap-and-trade might still occur if the credibility of global warming science were enhanced, assigning this contingency a 17% probability. Mr. Power thought the most likely direction for carbon policy will involve a patchwork of federal command-and-control measures, as described for the Energy Bill outcome above, but also attributed non-zero (roughly 5%) probability to the U.S. pursuing no substantive carbon abatement policy.

Mr. Cole analyzed the likelihood of cap-and-trade from the perspective of possible electoral events, attaching various carbon policy outcomes with different federal election outcomes, and then thinking in terms of likelihoods of the various possible election outcomes. The outcome of this thought process was that Mr. Cole ascribed 21% probability of cap-and-trade passing before 2015, with a greater chance that this would happen after the 2012 mid-term elections.

If the U.S. found itself without a cap-and-trade program by 2015, Mr. Cole envisioned draconian EPA–enforced provisions potentially forcing Congress' hand. In the event that the EPA were to strictly regulate carbon emissions under a best available control technology framework, Mr. Cole deemed it 35% likely that cap-and-trade would be in place by 2020, 60% likely that federal command-and-control mandates other than cap-and-trade would come into effect, and 5% likely that no other policies would be enacted. All in all, Mr. Cole's reasoning implied a 36% chance of cap-and-trade sooner or later, 49% chance of energy mandates rather than cap-and-trade, and 14% chance of a moderate degree of carbon regulation under the existing Clean Air Act provisions only.

Figure 2.A.6 shows a carbon policy event tree with associated probabilities from each expert. Because the experts' probabilities for each of the three types of policy outcome were quite similar, in the final probability tree, the three branches are assigned the average of their probabilities, which their concurrence.

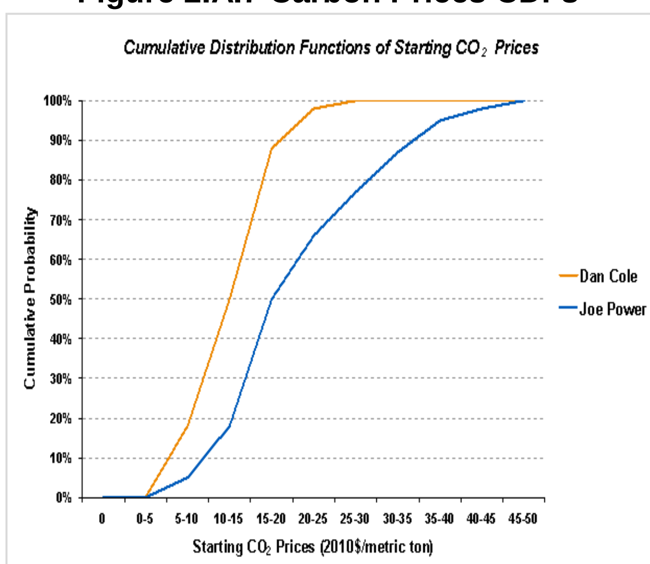
Figure 2.A.6 Carbon Policy Elicitation



Given that there would be a cap-and-trade policy outcome, there is also uncertainty on what the resulting carbon cap would be. Both experts preferred to express their uncertainty about the stringency of a carbon cap in terms of the uncertainty in what carbon price levels would occur. CRA elicited each expert's views on carbon price uncertainties, both for an initial year price and for future year prices.

The actual shapes of the starting price CDFs in Figure 2.A.7 were markedly different between experts. Mr. Cole expressed a soft price ceiling of $18 per metric ton, beyond which he judged diminishing chances for political passage. Mr. Power thought it possible that a bill similar to H.R.2454 (otherwise known as Waxman-Markey) in stringency could pass, which could lead to carbon prices as high as $45 per metric ton if key cost savers such as offsets prove to be less available than projected.

Figure 2.A.7 Carbon Prices CDFs

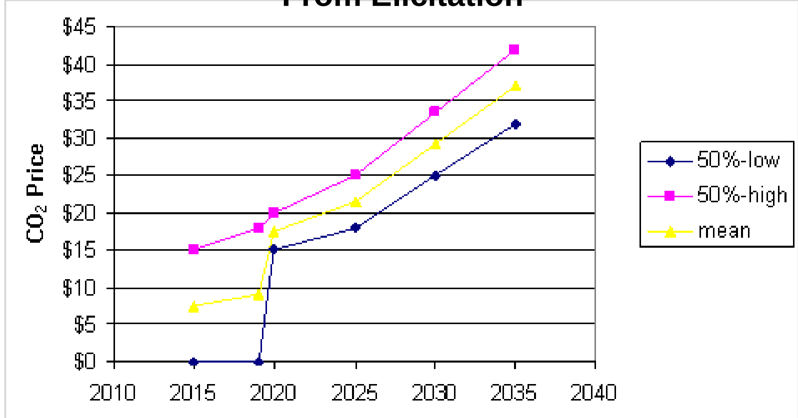


In order to integrate the experts' divergent carbon price paths, CRA and the Ameren Missouri carbon policy experts jointly decided to do the following. First, linearly combine the two probability distribution functions, giving each expert's curve

50% weight. Then, from this single curve, create 50%/50% discrete price points, where the high (or upper 50%) point represents the mean of the upper two quartiles of the distribution and the low (or lower 50%) represents the mean of the lower two quartiles.

This approach produces the uppermost pink path and lowermost blue path shown in Figure 2.A.8, with each path representing the mean for prices spanning the upper and lower 50% of the overall cap-and-trade probability distribution, respectively. Of note is that the lower 50% path stays at a $0 price level through the 2020 timeframe. This is indicative of the non-zero probability that each expert assigned to cap-and-trade not passing until after 2015.

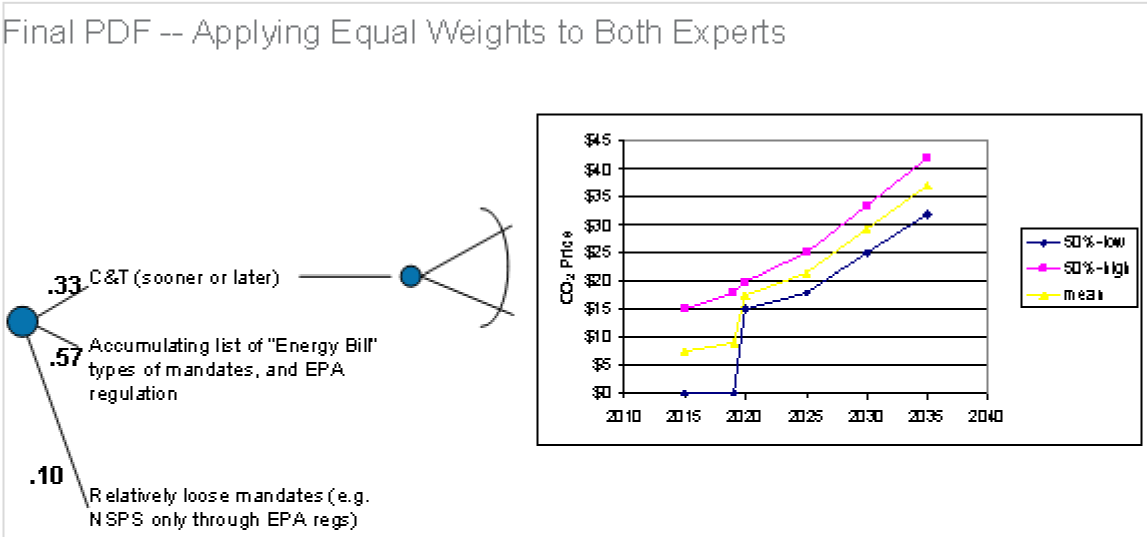
Figure 2.A.8 Discrete CO2 Price Paths Derived From Elicitation



The middle yellow line in Figure 2.A.8 represents the mean of the linearly-weighted distribution, which would be the single price path to use if the final probability tree were to reflect only the three-branched uncertainty on the qualitative approach to carbon policy. If the 50%/50% carbon price paths in Figure 2.A.8 were to be used, then the final probability tree would require a four-branched uncertainty node for carbon policy uncertainty alone, resulting in a much larger total number of branches in the full probability tree. As will be clarified later, Ameren Missouri opted to collapse the two "50%" CO2 price paths into one mean trajectory as part of the tree trimming process.

Figure 2.A.9 shows the final probabilities attributed to each carbon policy branch of the final probability tree before sensitivity analysis.

Figure 2.A.9 Elicited Carbon Policy Tree Branches



Natural Gas Prices[6]

The elicitations of the probability distribution for natural gas prices from subject matter experts Mssrs. Massmann and Schukar shared some common elements. At the outset of the interview, both experts chose to assess long-run prices defined to be the Henry Hub price stated in 2010$/MMBtu, and we agreed to define "long-run" as a three-year average of prices centered on each point in time. Both wished to state their views about prices for a near point in time (we started with 2015) separately from those for later points in time.

Ultimately, for later points in time, we elicited a price distribution only for 2025, because both experts felt that their probability distribution on gas prices in yet later years would be the same. Thus, we did not perform any direct elicitation for price outcomes beyond the 2025 time point, but simply applied the same distribution in later years as elicited for 2015.

Consistent with the analysis assumptions from the carbon elicitation, both experts were told to expect that no new coal plants other than those currently under construction would be built until they could be built to include carbon capture and sequestration. Also, CRA reminded both experts to assume there would be no other carbon policy in place when assessing possible future natural gas prices, because the model itself would endogenously adjust their price projections to incorporate the effects of natural gas demand increases, and carbon adders.

In order to assist in the discussion of possible future events, and to provide a common basis of understanding of the past, CRA provided both experts with a chart of natural

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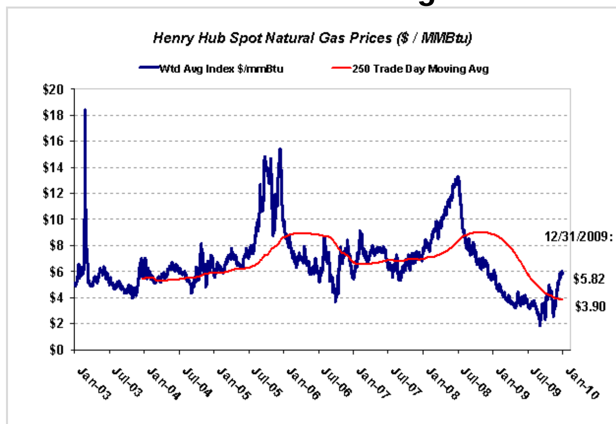
[6] 4 CSR 240-22.040(8)(A)3.; 4 CSR 240-22.040(8)(A)1.A.; 4 CSR 240-22.040(8)(A)1.E.; 4 CSR 240-22.040(9)(C)

gas prices at Henry Hub from 2003 through 2009. The chart used is reproduced below in Figure 2.A.10. In the conditioning portion of the interview, Mssrs. Massmann and Schukar expressed the same base of understanding for the spikes and troughs over the past observable in the chart, attributing them to various events such as extreme cold, Hurricane Katrina, coal delivery problems, global economic factors, domestic economic factors, shale gas and excess storage.

Figure 2.A.10 Henry Hub Natural Gas Prices from 2003 through 2009



In January 2010, CRA met with Mr. Schukar to elicit his views on natural gas prices. Mr. Schukar mentioned that his recent focus has concentrated more on drivers of prices and less on actual price levels. The drivers he mentioned were shale gas, demand for natural gas in the electric sector, and general supply and demand dynamics.

Mr. Schukar also explained his view that history has tended to repeat itself, and acknowledged mental model in which he tends to expect prices to always revert to a mean. For 2015, Mr. Schukar felt that the state of the economy would be a primary driver of natural gas prices. Two states of the economy that were discussed: (1) the U.S. economy returning to normal growth (GDP growth about 2.5%), and (2) the U.S. economy experiencing a double-dip (return to recession and slow growth of 0.0% to 0.5%). If there were a return to normal growth, then Mr. Schukar felt that the range of natural gas prices in 2015 could be as low as $3.50 and as high as $10.00. In the double-dip scenario, Mr. Schukar expressed a range of natural gas prices in 2015 from as low as $3.50 (given continued technological improvements) to as high as $8.00.

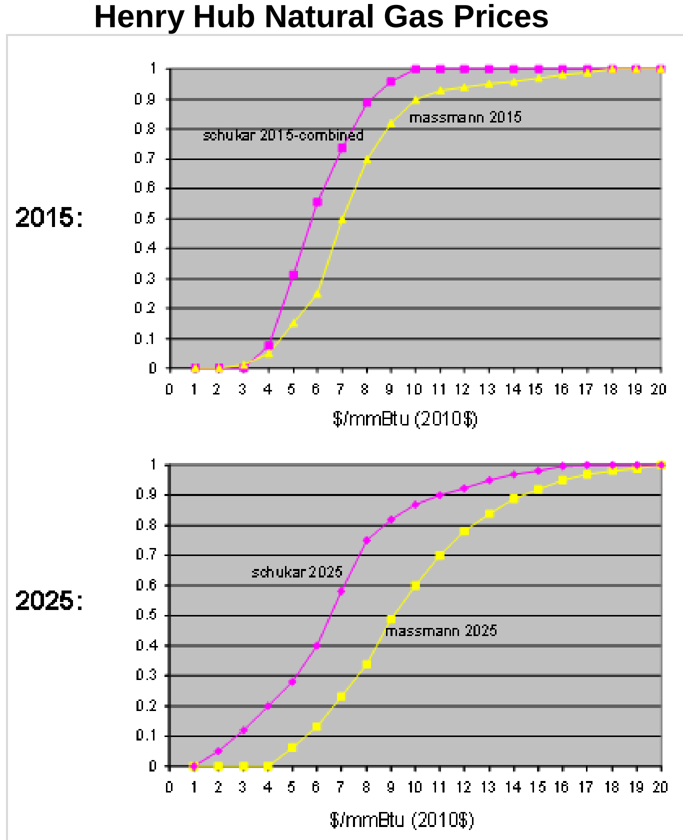
Mr. Schukar felt that natural gas prices in 2025 would not be correlated with prices in 2015, consistent with his belief in reversion to the mean. The key drivers of price in 2025 that Mr. Schukar identified were: new sources of supply (shale, methane hydrates), extraction costs, environmental policy (drilling and carbon), the fuel mix of electricity generation (renewables, fuel cells), and the state of the global economy (particularly China and India). He felt that liquefied natural gas (LNG) was not particularly important.

In January 2010, CRA also met with Mr. Massmann to elicit his views on natural gas prices. Mr. Massmann cited the following factors that would lead to high prices: environmental concerns regarding shale (e.g., the impact of hydraulic fracturing on water), although he expected producers to be nimble in blunting environmental pressures; not-in-my-backyard (NIMBY) activism, most likely in the Northeast; and whether shale gas projections turn out to be too optimistic.

The potential game changers on the demand side are: the stringency of CO_2 policy and also coal and nuclear policy. (At this point, CRA reminded him that carbon policy would be addressed through the model and that he should not consider it in his elicitation), use of natural gas in transportation (fleet vehicles) or in distributed generation (fuel cells), and fuel cell-powered cars (at least 20 years away). Regarding the fuel cells and distributed generation, Mr. Massmann did not foresee significant penetrations until at least ten years out into the future, limiting these variables' impact within the IRP timeframe.

Mr. Massmann's initial distribution of prices was considerably higher than that from Mr. Schukar. This was revealed during the follow up conference call with both experts, and the two experts discussed the reasons for their own statements. During that discussion, Mr. Massmann decided he had not adequately removed carbon policy from his thought processes when assigning probabilities to certain natural gas price levels. He also concluded that he had overemphasized the role of price equivalence between crude oil and natural gas, which, in his estimation, would only occur if appreciable amounts of natural gas were used in transportation.

Figure 2.A.11 Elicited 2015 & 2025 Henry Hub Natural Gas Prices



Mr. Massmann indicated that he wished to make modifications to his own distributions in light of the inter-expert discussion, and a second elicitation was scheduled. Mr. Massman's final distribution for 2015 indicated a 30% probability of prices greater than \$8 and a 25% probability of prices less than \$5. He also gave additional probabilities as follows: greater than \$15 is 5%, greater than \$10 is 10%, less than \$4 is 5%, and less than \$5 is 17%.

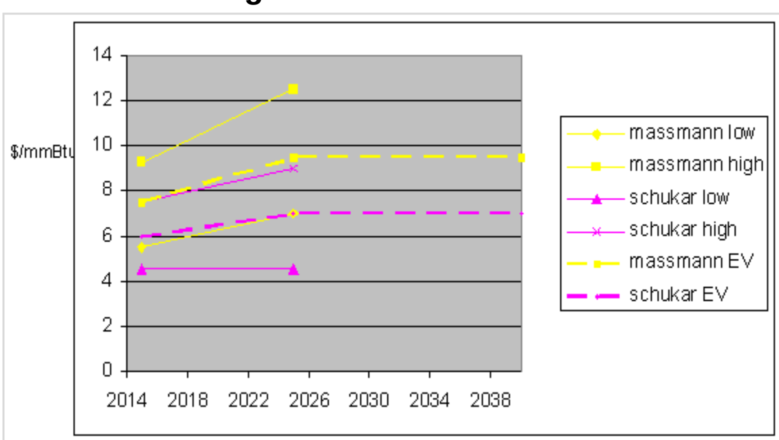
Figure 2.A.11 displays the final cumulative probability distribution functions of 2015 and 2025 Henry Hub natural gas prices from both experts individually.

The subjective views on natural gas prices of the two Ameren Missouri experts are substantially different from one other, reflecting different personal views of fundamental natural gas market dynamics. Both experts could envision a wide range of possible price levels in any year, and differed in the most likely price levels within that range. Thus, it was decided that it would be best that the two natural gas price branches reflect this fundamental difference of opinion about the long-term average price tendency, rather than combine their views into a single distribution.

Given the need for a price path, CRA and Ameren Missouri agreed to do the following. In 2015 and 2025, determine each expert's probability-weighted average price to form an expected-value, or EV, trajectory. Each of these EV trajectories would be assigned a probability weighting of 50% in the probability tree, attributing equal credit to each expert.

The dotted lines in Figure 2.A.12 represent the EV trajectories where the solid lines represent the 50%/50% brackets for each expert. This figure demonstrates how effectively the EV approach assimilates the continuous probability distributions of each expert into two discrete price pathways.

Figure 2.A.12 Establishing Natural Gas Price Paths From Elicited Data



Compliance References