THE Brattle GROUP

Brattle Review of AE Planning Methods and Austin Task Force Report

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Scope and Approach

Brattle was asked to review recent AE studies and the underlying planning tools to determine whether the methods and assumptions used are well-suited and well-applied to the issues and opportunities facing AE generally and to the goals and suggestions posed by the Austin City Council Task Force in its June 2014 report. Brattle was also asked to review the assumptions underlying the Task Force report. Our review is based on consistency with widely used methods in the industry, care in use by AE, and reasonableness of assumptions, not on similarity of forecasted costs or needs to any other assessment of AE's rersource alternatives. Brattle did not construct or prepare alternative models to test or compare either AE or Task Force results.

Brattle reviewed recent AE and ERCOT cost and performance statistics, planning studies and summaries of AE modeling results, topical reports, financial statements, and consulting studies that AE has procured in the past 2-3 years, as well as the Task Force Report and publicly posted inputs to it from various stakeholder groups. We also had extensive interviews with AE planning personnel to probe how assumptions were made or supported and how modeling tools were applied. [1]

Our report first describes our assessment of AE's planning tools and studies, and then it comments on issues in the Task Force (TF) report that may merit further study.

Review of AE's Planning Methods and Assumptions

Resource planning for utilities generally relies on a handful of key, recurring analytic problems and corresponding methods for forecasting future supply or demand management needs, incremental (avoidable) operating and construction costs, market costs and resource performance, overall risk and

1 While the authors of this report have reviewed and considered other Brattle analyses of relevant economic factors, the views expressed herein are solely those of the authors, and they may not be shared by other Brattle employees nor always consistent with Brattle findings and opinions offered in other contexts.

exposure to specific uncertainties, and resulting ranges of benefit/cost ratios or net present values (NPVs) across alternative types and schedules of possible resource additions and load management programs. In regard to the system expansion plans under consideration by AE, the most important of these analytic methods and assumptions appear to be:

- The future cost of natural gas
- The expected price or penalty for CO2 emissions
- Technology costs and performance capabilities for renewables and new technologies such as storage
- System modeling to capture expected market and system performance
- EE and DSM potential

The Brattle authors have reviewed tools and foundational studies used at AE for each of these. <u>Our general assessment is that the AE methods are careful and consistent with industry practices, and the range of input assumptions considered and possible resource plans compared is reasonable</u>. We have some specific suggestions for possible enhancements, identified below, but there is nothing to suggest that there is a fundamental methodological gap or problem in the AE planning tool kit and planning processes. (Our remarks are presented first as descriptions of what we observed, reported in this font, *followed by comments on that approach in italics*.) More specifically, in regard to each of the above:

<u>Natural Gas Outlook</u> – AE relies primarily on natural gas industry forecasts from consultants specializing in the industry. This is a common practice in the electric industry, as the supply conditions in the gas industry surrounding rig counts, marginal costs of development and extraction in different regions, production vs. offtake capacity, and other price-determining factors are complex and detailed, benefitting from industry focus and experience. The forecasts AE takes from its well-regarded advisors (Wood-MacKenzie) are reasonable in terms of harmony with near term market forward prices for gas as well as foreseeable influences on gas market balance over the next decade or so (such as coal plant retirements or LNG export terminals causing episodic price increases for a few years at a time before supply can fully catch up with demand). It also applies alternative high and low cost scenarios based on structural conditions suggested as extreme by its consultants. These too are plausible and consistent with the approach taken by many utilities.

> *Brattle often advises its clients on risk management goals and approaches, and in so doing often relies on market implied volatilities to determine the risk ranges for future natural gas and spot power prices. The high-low range used by AE is somewhat narrower than recent forward market volatilities suggest is possible for the near term (next one or two years). AE may want to supplement its structural basis for gas risk analysis with a more statistical one based on market price behavior.*

Expected price or penalty for CO2 emissions

At present, there is no policy in Texas, ERCOT, or nationally to impose controls or price penalties on emissions of CO2, though the US EPA has recently promulgated a proposal under its 111(d) authority to set CO2 emission rate limits from existing fossil generation, to be phased in from 2020 to 2030 (and presumably continued and strengthened thereafter). Most utilities in the US, including AE, build some kind of simulated economic penalty into evaluating generation investment alternatives when the associated assets have CO2 emissions that are likely to be eventually limited or penalized. In AE's case, it uses the CO2 price forecasts that Synapse Energy (a nationally active consulting firm) prepared in 2014 for [ERCOT],[2] based on its own survey of what many utilities and regulatory commissions have been doing in resource planning, and on what price levels for CO2 emissions have been projected under previously proposed national legislation.

In our experience at Brattle, these Synapse projections are slightly on the high side of penalties that most utilities apply, reaching \$35/ton in nominal terms by as early as 2028 in the base case and as early as 2023 in the high scenario.[3] By contrast, the prices of CO2 emissions in the US RTOs that are already limiting it are mostly around \$3-5/ton (as is also the case in the EU, which has been controlling CO2 via cap and trade for several years), and these are not projected to increase much in forward trading. However, US EPA's own estimates of the marginal cost of compliance with its 111(d) proposal are around \$30-35 in real terms (more like \$42 nominal) by 2030, and the Synapse/AE nominal price projection is also below the real "social cost of carbon" of \$35/ton in 2007\$ that was estimated by the U.S. Governmental Interagency Working Group in 2013 for use in federal cost/benefit analyses

> *The values for carbon being imputed by AE as penalties for its fossil generation and as benefits for its renewable resources are well grounded in public environmental studies and are slightly more aggressive (favoring low carbon resources) than we have seen many utilities use.*
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> *If CO2 policies and prices comparable to what AE has projected are not ultimately adopted, realized costs from a resource plan that strongly emphasizes renewables will be more expensive than a plan optimized for lower CO2 restrictions.*

Technology costs and performance capabilities for renewables and new technologies – AE has been more active than many utilities in evaluating and procuring renewable generation technologies, so it has a rich basis for evaluating the likely costs and performance of additional wind and solar on its system. A local perspective on such matters is important, because these resource characteristics are very situational (because they are based largely on local weather patterns, as well as on local costs for land and construction). Most of AE's solar resources to date have been available only at prices that are in excess of the costs of conventional resources, hence they require rate increases to incorporate them into the

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2 Austin Energy, 2014 Resource Plan, Workshop 2, p. 15.

3 Austin Energy, 2014 Resource Plan, Workshop 2, p. 15.

supply mix. However, that increase is tempered by profits from selling its economical generation into ERCOT. Recently AE has obtained PPAs for utility-scale solar (in W. Texas) and wind that are highly competitive with the unit costs of new gas generation – albeit with less controllability and overall utilization. AE has projected it will continue to be able to acquire utility renewables at essentially the best recent procurement prices, escalated for inflation.

> *These projected prices are below what most of the industry has experienced, though many higher cost estimates show reductions in the next few years towards the recent AE levels.*[4] *While costs have fallen rapidly in the past, there are reasons to believe this pace will slow or be reversed for a while, due to significant reductions in tax credits for renewable investment and output, anti-dumping restrictions on PV panels from China, and market adjustments to recent past excess production capacity.*

> *It is possible that AE will enjoy future cost reductions in solar resources that become materially below recent experience (and below AE's projections), if industry costs continue to fall as rapidly as in the past. If so, it will be prudent for AE to wait until then pursue more solar, rather than plunge in more aggressively now on that expectation (or hope), as waiting for those reductions will make the eventual service more economical.* [5]

Community-scale (at distribution voltages) and rooftop solar are typically about twice as expensive (or more) as utility solar, by virtue of being less flexible technology (e.g., not dual axis), requiring more interconnection and inversion per kW, and being located in regions (here, Austin) with less persistent sunshine than utility solar may be located (e.g., W. Texas). As a result, these local solar technologies are more expensive than conventional fossil generation, even after reflecting their carbon benefits.

> *Integration costs for local solar are not yet well understood for most of the utility industry. These can include having to provide low voltage circuit reinforcements to increase capacity and make re-routing more possible on otherwise mostly radial systems, new flow monitoring and control systems to understand the real-time state of the distribution system, smart flow and production controls, and new customer information systems and billing mechanisms. AE has not yet developed a rich view of these considerations as a factor in deciding where or how fast to adopt local renewable generation. In principle, storage technologies can mitigate some (but not all) of these concerns, but that technology is so far, expensive and not yet widely enough available to be presumed an economical solution.*

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[4] See, e.g., Lazard "Levelized Cost of Energy Analysis, version 8.0", Sept. 2014.

[5] Methods of real option analysis or decision analysis of multi-stage decisions can be applied to determine the optimal time/conditions to invest when there is potential for material changes in cost or risk in the future, and relatively low opportunity costs of deferring currently attractive investments.

In general, the output of renewables is both difficult to predict and unlikely to be reliably correlated with peak loads or peak prices (esp. for wind). AE's is well aware of this issue in drawing comparisons to conventional resources, and in assessing how renewables would complement (or replace parts of) an existing generation portfolio.

> *AE's projections of renewable resource performance are closely tied to actual experience and so reflect the levels and time patterns of output likely to be realized relative to load and relative to likely peak power price market conditions in ERCOT, as well as the uncertainty in those output patterns. One insight from this detailed analysis (also found at other utilities) is that the output of renewables must be backed up by a large and flexible portfolio of conventional generation (such as in the rest of ERCOT), or by new and potentially quite expensive storage technologies, as well as hedged against price spike risks (should it become unavailable during peak hours). AE's hedging methods and targets recognize this, but it is a complex problem that may merit increasing scrutiny as renewable use increases.*

<u>System modeling to project marginal costs, identify attractive resource additions, and predict likely rate impacts</u> – AE uses a system simulation tool called UPLAN to project how its load and fleet will interact with the ERCOT market. This is a widely used, commercially available planning tool that is advantageous to analyzing ERCOT, because it simultaneously assesses the lowest cost way of providing energy while also assessing how much of what kinds of backup and flow-control assets are needed to assure the feasibility of power deliveries to all locations and the ability to provide timely load-following for grid protection in ERCOT. Thus it reports both expected hourly nodal prices (locational marginal cost pricing, as has been in effect in ERCOT since 2010) and the associated ancillary service prices and requirements. The latter is especially important as more renewables are added to a portfolio, because they can increase short term uncertainty in net load levels.

These UPLAN simulations are conducted at least annually with a 10-20 year look-ahead (and monthly or more often with a 2-year look) using network inputs and resource addition (and retirement) expectations that are obtained from ERCOT (and then adjusted for any alternative AE plans of its own). The model price results are calibrated to the ERCOT forward prices for the first simulation year, then extended for 10 years into the future using detailed plant operational economics (for all of ERCOT). Economic conditions in the decade thereafter are obtained by extrapolating the last simulated year using inflation rates, to allow determination of 20-year NPVs (spanning most of the life of new assets). CO2 penalties are not directly included in the simulated market operations, because there is no such practice in place in ERCOT's actual scheduling, but measures of CO2 output by unit (and on the margin for the whole market) are tracked and used to add back cost and operating penalties (or revenues) under alternative CO2 scenarios. Among the reported outputs are how AE would be in compliance with the EPA 111(d) rate standards (which its projections show should be met by a wide margin). Alternative CO2 price levels, as well as alternative gas costs and load levels are also evaluated for each major resource plan.

AE then combines this energy market simulation data with associated fixed cost and financial information about the rest of its system (including the construction costs of new plants and their associated T&D expenditures) to evaluate alternative resource plans on a customer-impact basis, using many different metrics (such as total present value cost, or NPV, annual average rates, CO2 emissions, and others). Further, these metrics are simulated using Monte Carlo techniques across a wide range of uncertain external conditions (gas prices, load growth, etc.) to estimate their expected values as well as their potential extreme values under unlikely high cost conditions (the 95th percentile across the foreseen distribution of uncertain input factors).

> *This integrated approach to energy market simulation, system total cost and rate impact modeling, and risk assessment is quite sophisticated and in keeping with industry practices at well run utilities. If anything, applied parameters for environmental protection and other local policy goals are more favorable to such practices than many utilities utilize.*
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> *In the future, as environmental policy towards CO2 becomes clearer, and if/as the trajectory of costs for new technologies improves, it may become necessary to simulate the second decade of a 20-year period explicitly, rather than by inflationary escalation. This is because the structure of the market may shift away from strong reliance on high voltage wholesale generation towards more retail sources and end-use controls, and in so doing, the character of what assets are needed at wholesale (and resulting prices) may also change dramatically. It may also become necessary to simulate CO2 prices endogenously with market prices, assuming a price-based control mechanism is ultimately adopted.*
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> *The increasing use of renewable resources is making the prediction of wholesale price formation more difficult, as real time price spikes due to sudden changes in renewable performance can become as or more important than system coincident peak load. There are new system simulation models emerging that take into account the short-term forecasting error in renewable performance and that make corresponding adjustments in unit commitment and ancillary service pricing (which in turn affect energy prices). These new modeling techniques may be increasingly important to AE and other ERCOT members.*

<u>EE and DSM potential</u> – AE has retained consultants (DNV GL -- KEMA) to provide recent, detailed assessments of what incentives would be required to increase EE and DSM program targets from 800MW to 1,200MW or more by 2020.[6] Those studies found that it should nearly be feasible to achieve this large an increase with a high level of customer participation provided that significant cost-sharing incentives are paid to the EE and DSM adopters -- potentially up to 100% of the underlying equipment

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[6] The upper end of this range is substantially higher than the goal for the State of Texas, which plan on reducing electricity consumption by 5% per year for 10 years for a total reduction of about 30% by 2020. Source: Senate Bill 898 (82nd R), effective September 1, 2012 – August 31, 2021. Given AE's expected load of about 2700 MW (Resource Plan p. 33) in 2020 a goal of 1,200 MW corresponds to approximately 44%.

costs.[7] This would entail roughly a 5-fold increase in program costs (around $1.5 billion vs. $300 million under current program expenditures),[8] so the marginal benefit-cost ratios (TRC test) of the extra MWs would be lower than in the past, but still in excess of 1.0 (on average – marginal ratios for specific programs, if examined, were not reported in the materials Brattle reviewed).

It is important to recognize that the cost of obtaining EE becomes more and more expensive as over time. For example, obtaining 1,000 kW of savings in 2014-16 may be obtainable at $1,000 / kW whereas the price may approach $6,000 - $8,000 in 2020-2022 and a similar pattern for DSM.[9] This is especially important for AE as the utility already has been very active in this arena (hence has harvested some of the "low hanging fruit").

> *This increased DSM goal seems to be both well understood/analyzed by AE, as well as appearing to be feasible and potentially attractive. But, its impacts on non-participants or its interaction with the attractiveness of other system adjustments was not evaluated. (For instance, significant new solar technology may reduce the EE benefits, or v.v.). It may also not be the optimal approach to avoiding future carbon emissions, if the marginal costs of attracting reliable DSM increase faster than the improving costs of clean generation technologies.*
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> *Notwithstanding the technical potential or economic feasibility of achieving nearly 1,200 MW of demand reductions by EE and Demand Response, this is an ambitious target, representing much of the growth AE would otherwise experience and perhaps becoming a material component of the reliability of AE's system. The more such programs are pursued, the slower the AE load growth (as intended), which can make it more difficult to add the direct and integration costs of new resources into the AE mix without requiring rate increases.*

<u>In summary</u>, we find AE's methods to be well-suited to the initiatives it is considering and the goals and targets the Austin Task Force has proposed (discussed below), but various enhancements may prove useful in the future. These relate to: using a wider range of gas prices for risk analysis, making CO2 prices endogenous to system models, not extrapolating the second decade of system simulations, incorporating real time renewable performance uncertainty into planning tools, using real options or decision analytic methods to determine whether to wait for emerging technologies to improve, assessing integration costs at low voltage for large scale use of renewables, and more analysis of rate impacts generally and non-participant impacts specifically.

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7 KEMA, "Austin Energy DSM Market Potential Assessment", (KEMA Report), and "Discussion Paper on DSM Savings Potential and Costs Over Time" (GNV-DL). Estimated demand savings were estimated at 861 MW by 2020 (p. 21)

8 DNV-GL Paper p. 4.

9 *Ibid*, p. 7 and 11.

Key Goals and Critical Factors of Recommendations in the Task Force Report

The Austin City Council's Energy Task Force (TF) has put forward an ambitious agenda for accelerating the decarbonization of AE's services, largely by encouraging early retirement of some fossil generation (Fayette, Decker) and replacing them with renewables, conservation and demand management, and distributed resources. Several of these have been codified in Council resolutions that adhere generally, but not entirely, to the TF proposal. More specifically the Council's plan calls for:

- No CO2 emissions from AE generation by 2030
- Early retirement of Decker and Fayette generating stations, to be replaced largely with solar (600MW utility scale, 200MW customer premises) as the default future expansion resource
- Evaluation of increasing DSM goals from 800MW to 1,200MW by 2024
- Adding storage (200MW by 2024) to backup and integrate renewables
- Transforming AE into an integrated utility that goes beyond selling MW

The Task Force also stated the qualitative but important recommendations that AE develop its resource plan using data on new generation costs rather than on the basis of ERCOT data and market forecasts, and that solar resources become the default new generation technology for AE.[10] While directing AE to achieve these significant system transformations, it is also hoped or expected that these can be pursued with little or no increases in the cost of service relative to goals of staying below the median cost of energy in Texas and avoiding greater than 2%/year average increases in nominal rates.[11]

These TF recommendations were developed without the benefit of system analysis to evaluate whether they are economically optimal or even jointly feasible. Implicitly, there are several assumptions or conditions that would have to obtain for them to be all achieved and pursued as unconditionally and successfully as the TF report suggests:

- That solar and other renewables are, or soon will be, more economical than the resources they replace (either because fossil generation prices will soon increase (gas, CO2) and/or renewable costs will fall significantly) and that renewables can be (nearly) sufficient by themselves to follow load and meet demands reliably.
- That it is feasible to fully shift away from conventional generation resources to renewables and storage, and that there are few or only low incremental costs that would arise from pursuing an aggressive distributed generation and renewables policy, such as increased system costs for integration and information management.

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[10] The Report of the Austin Generation Task Force, p. 27 suggests alternatives to ERCOT grid stability.

[11] Austin Energy, "FY 2014 – 2018 Financial Forecast," p. 5.

- That a fast-paced adoption of new technologies is economically and environmentally optimal, regardless of whether the costs of those technologies may fall in the future or their performance capabilities may improve.
- That there are few or no material transaction costs associated with premature shutdown of viable fossil units, such as defeasement of associated debt, accelerated decommissioning expenses, transmission reinforcements to offset services lost from the shutdown plants (e.g., voltage support) or stranded contracting and financial costs.

While there are circumstances under which many of the above might obtain, it is also possible that many of these are difficult or unlikely to hold.

> *Given the dramatic, system transforming goals of the TF report, we believe it would be prudent for the City of Austin to thoroughly assess the potential costs and risks of the TF recommendations and initiatives, to determine if they are likely enough to be net beneficial in a variety of circumstances compared to alternative schedules and approaches AE might pursue for achieving very similar goals. This would be normal regulatory and public policy practice in most jurisdictions for programs of this scope and complexity.*

Review of Assumptions in the Task Force Report

A strong assertion or assumption of the Task Force is that it is possible and advantageous for AE to make its resource plans essentially independent from what conditions it expects to find in ERCOT.

> "Austin Energy should return to a planning methodology that compares generation alternatives to actual generation costs, not nodal market income alone."[12]

> "[I]n modeling the value of new generation, it should be compared with the cost of other new generation, not the value in the nodal market."[13]

The implicit motivation for this view may be the belief that ERCOT is designed to satisfy a different, narrower set of economic goals and priorities than are the current concern of the City of Austin, and therefore ERCOT may be irrelevant or even counterproductive to AE moving forward in the directions desired by the Task Force. It may also be the view that there are large negative social externalities to conventional utility resource planning and operations which increased use of renewables and less reliance on the market would mitigate. This may be partly true, but it is also the case that rapid shifting

[12] Austin Generation Task Force Report, p. 26.

[13] Austin Generation Task Force Report, p. 25. For AE's perspective, see Austin Energy, "Initial Response to the Report of the Austin Generation Resource Planning Task Force," August 22, 2014, p.2.

to reliance on renewables may come with its own complexities and indirect costs. In particular, basing resource plans on external costs that are not directly avoided by the utility could result in significant unintended and possibly inequitable rate increases, especially if participants in the new technologies are cross-subsidized by non-participants.

Reliance on ERCOT Market Outlooks in Resource Planning

We believe this suggestion to ignore the market is mistaken on a number of levels that are important to clarify so that there is as better chance of accomplishing the types of goals the Task Force and Council seek to achieve with minimal additional, unnecessary costs (or undue rate increases). Perhaps most importantly, participation in ERCOT is not optional for AE, and adapting to its rules and policies will intrinsically affect AE's costs. Hence they must be forecasted and considered, in order to determine whether and when it is advantageous to add new specific resources that might mitigate ERCOT costs or risks and reduce customer bills. More positively, there are numerous advantages to ERCOT participation that AE enjoys and which would be more costly to obtain without that involvement. These include:

- <u>Better ability to utilize all the output of a large fleet of renewable resources</u> – This is facilitated by ERCOT because the typical time pattern of renewable output does not closely match AE (or any other TX utility's) load shape. However, if renewables are used as a modest percentage of supply to a much larger system, they can be more fully utilized without hitting demand balance limits that would otherwise require curtailing their output.
- <u>More economic backup and integration of renewables to offset their output uncertainty</u> – Since unforeseen sudden shifts in weather (less/more wind or sun) will rapidly alter renewable output, they require backup resources capable of a fast response to these shifts. The exposure to those shifts is much smaller per average MW when there is a large pool of geographically dispersed renewables than when responding to a more local fleet. And with a pool of many conventional units on hand that can be directly scheduled by the RTO, it is not necessary for each renewable fleet owner to self-insure via its own peakers or partially used fossil plants.
- <u>Opportunity to optimize fossil generation within a large fleet scheduled for overall least operating cost</u> – Within ERCOT's pool, AE generation can sometimes be avoided by using lower cost generation elsewhere that is then not needed for that owner's local load, and conversely, when AE has more economic generation than its neighbors, it can sell more output than it otherwise needs for its own load for an operating profit that offsets fixed system costs.
- <u>Ability to hedge operating cost uncertainty</u> – The depth of suppliers, buyers and traders in ERCOT enables them to offer each other various forward contracts for power at prices set days, months, or seasons ahead of actual deliveries. Those hedges are essentially price insurance, which like all insurance is offered against the expected prices that would obtain absent the insurance. That is, they are priced based on traders' expectations of future spot prices for ERCOT power. Such hedges become more important the greater the reliance on non-dispatchable power sources. If those hedge products are cheaper than the fixed and operating costs of physically providing its own backup power, AE can save money for its customers and have the added certainty of what their costs will be.

Zero CO2 Output from AE Generation

While it is very attractive to envision a zero-carbon output situation for AE, in fact that may be impractical and uneconomic, and perhaps unnecessary and ineffective in reducing aggregate CO2 emissions. At this stage of technology development, the costs of abandoning fossil generation entirely would be quite prohibitive, as most renewables only produce power between 20-50% of the time and they are not sufficiently controllable to make that power available in perfect synchrony with demand (which power system stability requires). Some of those limitations are inherent to dependence on the weather, no matter how much technology improves in cost or efficiency in the future. The only currently foreseeable way to economically adjust for renewable resources' scheduling limitations is to use fast-response fossil generation (and hydro, where available) plus storage (though this also tends to be quite expensive). Further, by operating in ERCOT, AE will inherently rely on the use of fossil generation owned by others suppliers to balance its system (so it will still require and be using fossil generation, even if its own fleet were to become entirely non-fossil). If AE retires a fossil unit that otherwise is valuable in ERCOT, it may simply be replaced by another owner developing a replacement plant, possibly with little or no net CO2 emission reductions.

A more practical goal might be to seek zero <u>net</u> CO2 generation on behalf of AE's load. This approach would involve procuring offsets for any carbon emissions, ideally at a lower marginal cost than trying to configure the system for absolutely no CO2 emissions. The net effect on the environment would be the same as avoiding the local CO2, because CO2 is a very persistent pollutant (lasting up to 200 years in the atmosphere) and its undesirable effects are global, not local. In any case, evaluating a net zero strategy would inject some cost discipline into the pace and approach to an overall zero emissions goal.

Optimal Timing to Adopt New Technologies

As was discussed in the section on AE's planning methods, whenever there is significant uncertainty surrounding the future cost or value of a possible investment, it generally is not optimal to procure it at the first moment in time when it begins to show net benefits. If there is not too great an interim, incremental cost to the next best alternative, and if investing now will satisfy a long term need (hence preclude making a similar investment in the near future if/when costs become lower, the new technology performance is better, or market and regulatory risk conditions are more auspicious), it will be better to wait. Importantly, this does not involve waiting arbitrarily until some never-occurring point in the future when risk might be hoped to be fully resolved or the technology fully proven and stabilized. Instead, the lowest cost solution is found by finding the time of investment that balances the cost of further waiting against the expected rate of improvement in the value of the investment asset. This is a well-established result of "real option" valuation and decision analysis multi-stage planning.

The current situation is rife with such conditions, in that renewable technologies are improving rapidly, the cost of natural gas as a fuel to displace CO2 from coal generation is low, and there is material likelihood of market conditions becoming more auspicious and regulatory conditions more clear as to the value of renewables (esp. if a national CO2 policy is pursued). In addition, the costs and best practices for integrating large amounts of renewables into utility systems, esp. at low voltages, is not yet well understood or standardized, but progress is likely due to extensive exploration of these technologies in other venues (such as California, New York, and most of New England, among other regions).

Efficient Rate Design and New Service Specifications

An important factor in efficiently adopting new technologies that involve more distributed supply, storage, and load control near or behind customer meters will be the adjustment of tariffs and service terms to better reflect the actual cost structure of utility services. This is likely involving more fixed demand and customer charges and fewer per kWh charges, as well as the assessment and costing of incremental integration needs for different types, scales, and locations of new, distributed resources. This is a complex task both analytically and politically, in that it will require lots of customer interaction to reach a common understanding of why new charges may arise even as customers take less net power from the utility than in the past. A plan to develop these kinds of updated terms and conditions of service should be put in place in parallel to pursuing the new resource goals. This will also help to assure that there are not significant cross-subsidies from non-participants to participants who are deploying the new technologies and incentive programs.

Summary of Suggestions for TF and Council Initiatives

The goals and programs put forward by the TF and embodied in the recent Council Resolutions would continue to put Austin on the forefront of adopting innovative and environmentally attractive technologies and programs. However, those goals were articulated without the benefit of various kinds of system analysis that could readily be applied to help sharpen the pace and identify beneficial tradeoffs for how to achieve those goals most economically and fairly for the customers of AE. Further study and public review would be useful and normal for such significant policy recommendations.