Appendix E
Methods of Quantification

The Climate Action Plan used an overall analytical approach applied across the four greenhouse gas mitigation sectors. Key elements of the overall approach are described in the Quantification Methods Memorandum. The key elements are divided into the following three sections: Overall Approach, GHG Emissions and Emission Reductions, and Cost Analysis Methods. Separate memoranda, the "Common Assumptions Memos," focus on key analytical methods that are specific to each of the four Technical Work Group areas, and follow the Quantification Methods Memorandum.

Draft Quantification Methods Memorandum

New York State Climate Action Plan

Prepared for:

The New York State Energy Research and Development Authority
and
The New York State Department of Environmental Conservation
Albany, NY

Prepared by:

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INTRODUCTION

The purpose of the Quantification Memorandum is to explain the methodologies and identify key assumptions for developing sector-specific estimates of greenhouse gas (GHG) emission reduction potential, incremental costs, and cost effectiveness for Climate Action Plan recommended policies for New York. This memorandum also addresses the data sources/types and methods that will be needed to support the analysis of sector-specific GHG mitigation policy options associated with statewide implementation of aggregated technologies and best practices.

The first part of this memorandum discusses key elements of the overall analytical approach that apply across all four Technical Work Group sectors. The key elements are divided into the following three sections: Overall Approach, GHG Emissions and Emission Reductions, and Cost Analysis Methods. Separate memoranda, the "Common Assumptions Memos," focus on key analytical methods that are specific to each of the four Technical Work Group areas.

Overall Approach

Emission Sources

The project was divided into four Technical Work Group sectors to analyze the emission reduction potential and associated costs of individual GHG mitigation policy options and reflect the relationship between reduction potentials and cost per metric ton of carbon dioxide equivalent (CO_2e) emissions avoided. The four sectors include:

(1) Residential, Commercial/Institutional, and Industrial (RCI);

(2) Power Supply and Delivery (PSD);

(3) Transportation and Land Use (TLU); and,

(4) Agriculture, Forestry, and Waste Management (AFW).

The analysis of policy options will focus on those that are or may be applicable in New York State. When relevant, and as allowed by the availability of data, budget and project time, the analysis will include geographic differences in the application and costs of mitigation policies (e.g., New York City versus the rest of the state). At a minimum, in-state emission reductions and costs will be estimated for technologies and best practices as applied in New York State.

Subject to review by the Integration Advisory Panel, emission reductions will also be estimated for technologies and best practices applied within the state that result in emission reductions outside of the state. For instance, a major benefit of recycling is the reduction in material extraction and processing (e.g., aluminum production). While a policy may increase recycling in New York, the reduction in emissions may occur where this material is produced. Where significant emissions impacts are likely to occur outside the state, this will be clearly indicated. However, for the purpose of counting emissions reductions against New York's goal, only in-state reductions will be included.

Fuel Cycle Coverage

For the purposes of this study, the full fuel cycle represents the range of activities associated with fuel extraction, processing, distribution, and consumption. For the PSD, RCI, AFW and TLU sectors, GHG reductions for each mitigation policy option will be based upon the full fuel cycle because information is available to support this type of analysis for these sectors. Tracking the full range of fuel use inputs is essential for accurately tracking fuel cycle carbon emissions for technology options displaying very different performance characteristics. The approach involves identifying all the possible stages of the fuel cycle and quantifying the fuel input per unit of energy produced (electricity or fossil fuel).

Fuel cycle impacts will be reported for each source for which information is available to support a fuel cycle analysis. Where fuel cycle emission reductions are captured, there will often be two sets of emission reductions estimated: the total fuel cycle reductions; and those estimated to occur within the state. For the purpose of counting emissions reductions against New York's goal, only in-state reductions will be included. In most cases, these will be difficult to separate based on available information. Therefore, by default, the in-state reductions will often be those associated with fuel combustion and known in-state processes. Emission reductions from in-state processes associated with non-combustion reduction sources include only those processes that are known to occur within New York State (e.g., landfill emission reductions, but not the upstream GHG emissions embedded in the waste component) and exclude processes where the geographic origin of the mitigated emissions is uncertain (e.g., emissions from extraction/processing/packaging of virgin materials into usable products).

Life Cycle Coverage

For the purposes of this quantification, life cycle represents the energy and materials used for manufacture, its energy use during useful life, and disposal and/or capacity to be recycled. As the Climate Action Plan Council has conveyed interest in reporting in-state GHG reductions – with fuel-cycle reductions considered as co-benefits – full life cycle analyses may not be performed. Should sufficient data and parameters become available to execute a full life cycle analysis, CCS will include life cycle analysis, listing life cycle GHG reductions as co-benefits.

Pollutant Coverage and Global Warming Potentials

The analysis will cover the following six GHGs: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Emissions of these gases will be presented using a common metric, CO_2e, which accounts for the relative contribution of each gas to global average radiative forcing by multiplying the emissions of each pollutant by its Global Warming Potential (GWP)—a unitless factor representing the ratio of the radiative forcing of each GHG to the radiative forcing of CO_2 (the GWP for CO_2 is 1). Table E-1 shows the 100-year GWPs published by the Intergovernmental Panel on Climate Change (IPCC) in its Second, Third, and Fourth Assessment Reports. To be consistent with the GHG emissions inventory and forecast for the state of New York, the 100-year GWP's published in the Second Assessment Report of the IIPCC will be used to convert mass emissions to a 100-year GWP basis. Use of the 100-year GWP's published in the IPCC's Second Assessment Report is also consistent with U.S. Environmental Protection Agency (EPA) and IPCC guidance for consistency with how U.S. national, state, and country-specific GHG emissions inventories have been developed in the past.

Qualitative information on the criteria air pollutants and toxic air pollutants will also be included when this information is identified for individual technologies and practices in order to support co-benefits analysis.

Table E-1. 100-Year Global Warming Potentials from the Second, Third and Fourth Assessment Reports of the IPCC

Gas	100-year GWP (2nd Assessment)[1]	100-year GWP (3rd Assessment)[2]	100-year GWP (4th Assessment)[3]
CO_2	1	1	1
CH_4	21	23	25
N_2O	310	296	298
HFC-23	11,700	12,000	14,800
HFC-125	2,800	3,400	3,500
HFC-134a	1,300	1,300	1,430
HFC-143a	3,800	4,300	4,470
HFC-152a	140	120	124
HFC-227ea	2,900	3,500	3,220
HFC-236fa	6,300	9,400	794
HFC-4310mee	1,300	1,500	1,640
CF_4	6,500	5,700	7,390
C_2F_6	9,200	11,900	12,200
C_4F_{10}	7,000	8,600	8,860
C_6F_{14}	7,400	9,000	9,300
SF_6	23,900	22,200	22,800

* The methane GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor.

An inventory for elemental (black) carbon (EC) and organic carbon (OC) will also be developed, so that potential co-benefits related to climate forcing and regional haze can be assessed, at least in a semi-quantitative fashion. CCS will use methods that it has used in several other states to develop a base year and projection year EC/OC inventory.

Time Period of Analysis

Fuel cycle emission reductions and incremental costs will be calculated relative to the characteristics of the baseline that would otherwise prevail in New York up through the end of the planning period, 2030.

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[1] Second Assessment: http://www.epa.gov/climatechange/emissions/downloads/ghg_gwp.pdf 1995. Because only a summary of the Second Assessment Report if available online, an EPA document is cited which has the table from the IPCC report.

[2] Third Assessment: http://www.ipcc.ch/ipccreports/tar/wg1/248.htm, 2001.

[3] Fourth Assessment: http://www.ipcc.ch/pdf/assessment-report/ar4/wg1/ar4-wg1-chapter2.pdf, 2007.

The analysis will report annual emission reductions for 2020 and 2030. The present value of the cumulative incremental costs, and undiscounted cumulative CO_2e emission reductions, will be reported for the period starting with the initial year of the phase-in of the policy, up through 2030. For example, if an RCI policy includes a complete phase-in over time of more efficient plug load technologies (i.e., computers, televisions, video machines, etc) the annual GHG reductions will be reported for the years 2020 and 2030. The present value of the cumulative incremental costs and the undiscounted cumulative emission reductions will be reported for the entire period from the beginning of the phase-in up through 2030.

Start and End Years for Analysis

The beginning of the analysis period for which GHG reduction benefits and incremental costs will be calculated is the year 2011, considered to be the earliest year for which GHG mitigation options could be introduced in NY. The end of the analysis period is 2030.

Transparency

Data sources, methods, implementation mechanisms, key assumptions, and key uncertainties will be documented and supported by references to provide transparency on how the key analytical outputs for each policy option were developed and applied. Information provided by the state agencies and project participants will be used to ensure best available data sources, methods, and key assumptions using their expertise and knowledge to address specific issues in New York State. Modifications will be made through facilitated discussions.

Key Analytical Outputs and Metrics

GHG emission reductions

Net GHG reduction potential in physical units of million metric tons (MMt) of carbon dioxide equivalent (CO_2e) will be estimated for each quantifiable policy for each target year, 2020 and 2030, and cumulative reductions through 2030. As noted earlier, full fuel cycle or life cycle analysis will be used to evaluate net energy (and emissions) performance of policy options, as appropriate. Net analysis of the effects of carbon sequestration will be conducted where applicable. (See the section on "GHG Emissions and Emission Reductions" for additional details.)

Costs

Net capital, operating and maintenance (O&M), and fuel costs will be estimated for each of the policy options that are determined quantifiable. Costs will be discounted as a multi-year stream of net costs to arrive at the "net present value cost" associated with implementing new technologies and best practices. It is proposed that costs be discounted for all options in constant 2005 dollars using a 5 percent annual real discount rate. The nominal discount rate will be calculated by adding the projected inflation rate over the analysis period.[4] Capital investments

[4]The inflation rate for the analysis period is assumed to be 2.2%, subject to approval by the Integration Advisory Panel and Climate Action Council. Capital and other costs reported in nominal dollars will be converted to 2005$ using the inflation rate for the NY state region as reported by the Bureau of Labor Statistics (http://www.bls.gov/ro2/news.htm)

will be represented in terms of annualized or amortized costs over the project period. Discounting will begin in this initial year of the analysis period (i.e., assumes investment occurs in the beginning of the year). Policies that result in energy savings relative to the baseline technology or practice may result in a cost savings (recorded as a negative value). As noted above, the discount rate will be kept constant for the evaluation of all GHG mitigation options - risk and uncertainly will be accounted for by calculating option-specific cash flows that account for policy, practice, or technology differences.

Cost-effectiveness

The cost effectiveness for each quantified policy will be calculated by dividing the present value cost by the cumulative (undiscounted) reduction in metric tons of GHG emissions. Because monetized dollar value of GHG reduction benefits are not available, physical benefits will be used instead, measured as dollars per metric ton of carbon dioxide equivalent (tCO_2e) or "cost effectiveness" evaluation. Both positive costs and cost savings (negative value) will be estimated as a part of compliance cost. When combined with GHG impact assessments, the results of these cost estimates will be aggregated into a sectoral summary table and sector and economy-wide stepwise marginal cost curves.

Direct vs. indirect effects

Socio economic impact of policy options and scenarios will include direct effects, but will not include indirect and distributional effects. Direct effects are those borne or created by the entities, households or populations subject to the policy or implementing the new policies; for example, a policy encouraging the purchase of advanced technology vehicles would include an evaluation of the incremental cost of the vehicles, and the savings on fuel cost and associated GHG emissions. Indirect effects are defined as those borne or created by the entities, households or populations other than those implementing the policy recommendation; in the above example, this could be the number of jobs created/lost by the alternative GHG mitigation investments, or the reduction in ambient air pollution concentrations. Distributional effects refer to the extent to which a GHG mitigation policy design may result in disproportionate impacts on different regions, sectors, communities, or households. Some examples of direct and indirect net costs and benefits metrics are included in Annex 1 at the end of this memo for purposes of illustration.

End effects

For GHG mitigation options whose lifetimes extend beyond the end of the analysis period (i.e., beyond 2030), only costs and benefits that fall within the analysis period will be fully included in the analytical results. For long-lived investments (e.g., public transport infrastructure, nuclear power plants) whose costs and benefits extend beyond 2030, GHG reductions up through 2050 will be quantified in order to be able to offer a direct comparison with the 80 by 50 goal. In order to make this comparison, sectoral business-as-usual GHG projections will be estimated for the 2031-2050 period using simple extrapolation techniques, except for technologies that mature at the end of the study period or decline in effectiveness discontinuously after 2030. Incremental costs in the 2031-2050 period will be accounted for qualitatively in the write-up of results.

Non-GHG (external) impacts and costs

Environmental co-benefits such as reductions in criteria air pollutants which in turn would lead to reduced public health impacts from productive activities in New York are to be analyzed separately. Qualitatively, CCS will document measures that are expected to have other non-GHG impacts, including water quality, water use, solid waste reduction, and environmental justice issues and will provide information as available and needed to support quantification of these impacts.

Biomass supply & demand

Within the AFW Common Assumptions memorandum, estimates of biomass supply will be prepared. Estimates are provided for all known feedstocks, including municipal solid waste fiber, in units of dry tons and million British Thermal Units (MMBtu). During the course of GHG quantification, CCS will maintain a spreadsheet to be used by the team to track demand by each mitigation approach (e.g., biomass to energy, liquid biofuels production).

Uncertainty / Sensitivity Analysis

Key uncertainties and feasibility issues will be identified and discussed qualitatively. For instance, the certainty of energy price forecasts and technology change rates may vary significantly across certain sectors and actions. Characterization of the source and potential magnitude of uncertainty will be useful to policymakers as they make future policy decisions. To the extent that data are available and time and resources allow, a quantitative assessment of uncertainty or certain parameter sensitivities will be included in the analysis of policy options by conducting sensitivity analysis.

GHG Emissions and Emission Reductions

New York State GHG Emissions Inventory and Forecast

To estimate statewide impacts associated with potential policies, information on current and future energy use and the extent of application (penetration) of both baseline and policy options will be needed. Working with CCS, NYSERDA has prepared a comprehensive GHG emissions inventory for 1990 through 2008 and a forecast to 2030 for all emission source sectors. The emissions inventory and forecast has been prepared at the state-level representing a planning inventory rather than a compliance inventory. Forecast data used to support the development of New York's 2009 State Energy Plan were used to revise the forecast of energy demand and emissions. Historical fuel use data used in preparing the inventory are provided in a separate publication; these data rely on data published by the U.S. Energy Information Administration.[5]

Calculation of Emission Reductions for Policy Options

Emission reductions for individual policies will be estimated incremental to baseline emissions based on the change (reduction) in emissions activity (e.g., physical energy units) or as a percentage reduction in emissions activity (e.g., physical energy units or emissions) depending

[5] Patterns and Trends, New York State Energy Profiles: 1993-2008, prepared by New York State Energy Research and Development Authority Energy Analysis Program.

on the availability of data. This information will be needed to support the cost-effectiveness calculation for each policy option.

Fuel- and pollutant-specific emission factors will be used to convert physical units of emissions activity to emissions. The emission factors will be based on those that NYSERDA uses to prepare the GHG emissions inventory and forecast for New York State, and are provided in the Sector-specific "Common Assumptions" memoranda. For fuel combustion sources, fuel-specific oxidation factors will be used with emission factors to estimate emissions. Fuel combustion oxidation factors refer to the percentage of fuel that is fully oxidized during the combustion process. Table E-2 provides the oxidation factors to be used for this analysis; these factors are based on those used in the EPA's most recent GHG inventory for the U.S.[6]

Table E-2. Fuel Combustion Oxidation Factors

Fuel	Oxidation Factor
Coal	0.990
Natural Gas and LPG	0.995
Distillate and Residual Oil	0.990
Municipal Solid Waste	0.980

Energy Conversion Factors

Energy conversion factors refer to the energy density of fuels used in New York. These factors are provided in the Sector-specific "Common Assumptions" memoranda. Energy conversion factors obtained from NYSERDA will be used for this project. Otherwise, default energy conversion factors will be taken from Table Y-2 (Conversion Factors to Energy Units (Heat Equivalents)) of Appendix Y in the EPA's most recent GHG Inventory for the U.S.[7]

Cost Analysis Methods

Cost Effectiveness

Because the monetized dollar value of GHG reduction benefits are not available, physical benefits are used instead, measured as dollars per tCO_2e (cost or savings per metric ton) or "cost effectiveness." Both positive costs and cost savings (negative values) are estimated as a part of mitigation cost. When combined with GHG impact assessments, the results of these cost estimates will be aggregated into a stepwise marginal cost curve that can be broken down by sector or subsector as needed, as well as sub state region for key measures.

The net cost of saved carbon of a proposed policy option is calculated by dividing the cumulative future streams of incremental costs, discounted back to the present time, by the cumulative

[6] U.S. EPA, April 2010. Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2008. Available at: http://epa.gov/climatechange/emissions/usinventoryreport.html.

[7] Available at: http:/yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/LHOD5MJTCL/$File/2003-final-inventory_annex_y.pdf.

undiscounted net CO_2e reductions achieved by the technology or best practice. Mathematically, the equation to be used is as follows:

$$\mathrm{CSC} = \frac{\displaystyle\sum_{t=0}^{n}\left\{\frac{((LC_m - LC_r) * A_t)}{(1+D_r)^t}\right\}}{\displaystyle\sum_{t=0}^{n}(CO_2e_r - CO_2e_m)}$$

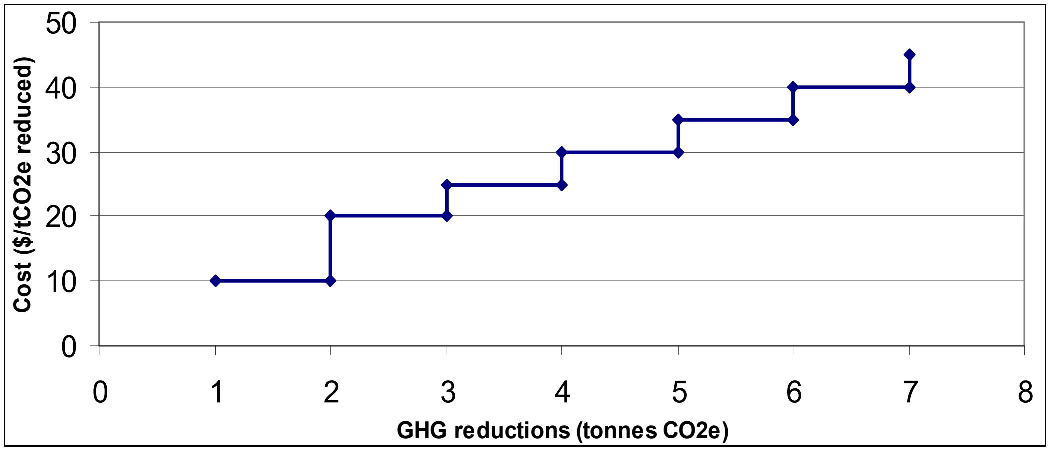
where:

CSC	=	Cost of saved carbon (or cost-effectiveness) of a technology or best practice, $/tCO_2e$ avoided
LCm	=	Levelized cost of a technology or best practice, $/activity unit
LCr	=	Levelized cost of the baseline or reference technology or best practice, $/activity unit
A	=	Amount of activity affected by the technology or best practice in year t, activity unit
Dr	=	Real discount rate, dimensionless
CO_2er	=	CO_2e emissions associated with the baseline or reference technology or best practice in year t, metric tons CO_2e
CO_2em	=	CO_2e emissions associated with a technology or best practice in year t, metric tons CO_2e
t	=	year in the evaluation period ($0 \leq t \leq 40$)

Activity units refer to a unit indicator of GHG emissions activity for a policy option. The activity units will vary depending on the Sector and within each sector the individual option. The activity units are used to normalize data for comparison of the policy option to the baseline. For example, for the Power Supply and Delivery sector, MWh of gross electricity generation could be used as the activity unit such that dollars per megawatt-hour ($/MWh) would be used as the activity unit for the “LCm” and “LCr” terms and MWh would be used as the activity unit for the cost terms in the equation.

The results of the analyses will be used to develop a GHG abatement cost curve which will rank each technology or best practice in the order of its cost effectiveness for reducing a metric ton of CO_2e emissions. This ranking will be represented in the form of a curve that is similar conceptually to Figure E-1. Each point on this curve represents the cost-effectiveness of a given policy option relative to its contribution to reductions from the baseline, expressed as a percentage. The points on the curve appear sequentially, from most cost-effective in the lower left area of the curve, to the least cost-effective options located higher in the cost curve in the upper right area.

Figure E-1. Example Cost Curve



The costs of each policy option that will be evaluated will be levelized and converted into dollars per activity unit. The cost components to be considered include capital, fixed O&M, variable O&M, and fuel costs. Other sector-specific costs (e.g., transmission of electricity) will be included as applicable to each sector.

The levelization calculation is similar to amortization and its purpose is to develop a level stream of equal dollar payments that lasts for a fixed period of time. The levelization formula to be used in the analysis is as follows:

$$LC = \frac{[PV * D_r * (1 + D_r)^t]}{((1 + D_r)^t) - 1}$$

where:

LC	=	Levelized cost of the a technology or best practice, $/activity unit
PV	=	Present value of discounted cost stream
D_r	=	Real discount rate, dimensionless
t	=	Levelization period, or number of years over which payments are to be made

There are several parameters that will be used in the levelization process. Some are technology-specific (e.g., plant lifetime, capacity factor), others are state-specific (e.g., state income tax rate), others are market-driven (cost of capital), while others are a matter of policy (e.g., real discount rate).

Capital Costs

Capital costs represent the material, equipment, labor, and other costs associated with the implementation of a policy option relative to the baseline or reference technology or practice. For policy options that require a capital investment, these costs will be annualized using a fixed charge rate (FCR), a factor that is the sum of the cost of capital (equals the cost of debt plus the cost of equity), taxes, and depreciation. Differences between public/private financing costs will be captured through sector-specific assumptions regarding equity/debt fractions and depreciation schedules. For long-term capital investments that extend beyond 2030, the investment will be annualized over its operational lifetime; only costs incurred within the 2011-2030 analysis period will be fully included in the presentation of quantitative results.

Annual O&M Costs

O&M costs refer to labor, equipment, and fuel costs related to annual operation and maintenance of policy measures and are differentiated into annual expenditures (i.e., variable O&M) and fixed expenditures (i.e., fixed O&M). Variable O&M estimates are provided in activity units over the full period of operation of the technology. O&M costs are described and included in the LCC when there is a differential between the baseline technology and the GHG-reducing alternative.

Forecast of Fuel Demand, Prices, and Costs

Fuel demand and price forecasts will be based on the information developed for New York's State Energy Plan. This information will include fuel demand and price forecasts for 2011 through 2030 by sector and fuel type in both physical (e.g., gallons, cubic feet, barrels) and energy (e.g., British thermal units [Btu]) units. The sectors covered include electricity generation; residential, commercial/institutional, and industrial; and transportation. The fuels covered include natural gas, petroleum (motor gasoline, kerosene, liquefied petroleum gas, distillate and residual oil), and coal, nuclear fuel, and renewable fuels (biomass and landfill gas). For the purpose of developing abatement cost curves, the fuel demand and price forecasts developed by NYSERDA, NYISO, and other sources will be used for all sectors. Fuel costs (including avoided fuel costs) will be calculated using this information along with fuel consumption estimates developed for each technology or best practice.

Avoided Electricity Generation Costs

For policy options in the RCI, agriculture, and waste sectors that reduce electricity demand, the amount and cost of electricity avoided will be estimated. Information on avoided electricity costs will reflect the consensus of the project research team, NYSERDA, and the Climate Action Council.

Interactions with the Regional Greenhouse Gas Initiative (RGGI)

RGGI is a ten-state agreement to reduce GHG emissions through a cap and trade system focused only on the supply of electric power. States within RGGI have negotiated a regional CO_2 emission cap for the power sector of 188 million short tons per year through 2014 (cap of 64 million short tons for NY), with the cap being strengthened by 2.5 percent per year over the period 2015 through 2018. The energy modeling undertaken to develop New York's State Energy Plan fully incorporates the RGGI program in the reference case forecast. Hence, all power sector GHG mitigation policies to be analyzed are considered incremental to the RGGI program since they will achieve greater GHG emissions than the RGGI program. In addition, a more stringent RGGI program itself will be analyzed as part of the PSD-6 option.

Documentation

Documentation of the work completed for each policy option for each sector will be completed in a template format that addresses the items listed below (among others) to ensure consistency for comparison of information and also assist with identifying data gaps that will be addressed.

Work Group Sector

Name of policy option

Policy Description

Policy Design (Goals and Timing for implementation and parties involved or affected by implementation of the policy.)

Implementation Mechanisms

Quantification: Estimated GHG Savings and Costs per $MtCO_2e$ (GHG reduction potential in 2020 and 2030, Cumulative GHG reduction potential, net cost, data sources, and quantification methods)

Key Assumptions and Uncertainties

Co-Benefits and External Costs (qualitative discussion)

Annex 1: Examples of Direct/Indirect Net Cost and Benefit Metrics

Note: These examples are meant to be illustrative and are not necessarily comprehensive.

A. Direct Costs and/or Savings

Transportation and Land Use (TLU) Sector

- Incremental cost of more efficient vehicles net of fuel savings, net of fuel savings.
- Incremental cost of implementing Smart Growth programs, net of saved infrastructure and service costs plus fuel savings and reduced consumption.
- Incremental cost of mass transit investment and operating expenses, net of any saved infrastructure and service costs (e.g., roads)
- Incremental cost of alternative fuel, net of any change in maintenance costs
- Net effects of carbon sequestration from land use measures

Residential, Commercial, and Industrial (RCI) Sectors

- Net capital costs or savings (or incremental costs or savings relative to standard practice) of improved buildings, appliances, equipment (cost of higher-efficiency refrigerator versus refrigerator of similar features that meets standards)
- Net operation and maintenance (O&M) costs or savings (relative to standard practice) of improved buildings, appliances, equipment, including avoided/extra labor costs for maintenance (less changing of compact fluorescent light (CFL) or light-emitting diode (LED) bulbs in lamps relative to incandescent)
- Net fuel (gas, electricity, biomass, etc.) costs (typically as avoided costs from a societal perspective)
- Cost/value of net water use/savings
- Cost/value of net materials use/savings (for example, raw materials savings via recycling, or lower/higher cost of low-global warming potential (GWP) refrigerants)
- Direct improved productivity as a result of industrial measures (measured as change in cost per unit output, for example, for an energy/GHG-saving improvement that also speeds up a production line or results in higher product yield)

Energy Supply (ES) Sector

- Net capital costs or savings (or incremental costs or savings relative to reference case technologies) of renewables or other advanced technologies resulting from policies
- Net O&M costs or savings (relative to reference case technologies) renewables or other advanced technologies resulting from policies
- Avoided or net fuel savings (gas, coal, biomass, etc.) of renewables or other advanced technologies relative to reference case technologies resulting from policies
- Total system costs (net capital + net O&M + avoided/net fuel savings + net imports/exports + net transmission and distribution (T&D) costs) relative to reference case total system costs

Agriculture, Forestry, and Waste Management (AFW) Sectors

- Net capital costs or savings (or incremental costs relative to standard practice) of facilities or equipment (e.g., manure digesters and associated infrastructure, generator; ethanol production facility)
- Net O&M costs or savings (relative to standard practice) of equipment or facilities
- Net fuel (gas, electricity, biomass, etc.) costs or avoided costs
- Cost/value of net water use/savings
- Cost/value of carbon sequestration from land use measures
- Reduced VMT and fuel consumption associated with land use conversions (e.g., as a result of forest/rangeland/cropland protection policies)

B. Indirect Costs and/or Savings across All Sectors

- Net value of employment and income impacts, including differential impacts by socio economic category
- Re-spending effects on the economy from financial savings
- Net changes in the prices of goods and services in the region
- Health benefits of reduced air and water pollution
- Ecosystem benefits of reduced air and water pollution
- Value of quality-of-life improvements
- Value of improved road and community safety
- Energy security
- Net embodied energy of materials used in buildings, appliances, equipment, relative to standard practice
- Improved productivity as a result of an improved working environment, such as improved office productivity through improved lighting (though the inclusion of this as indirect might be argued in some cases)
- Higher cost of electricity in the region

AFW Common Assumptions Memorandum - Draft

To:	NYS Climate Action Plan Agriculture, Forestry, and Waste Management Technical Workgroup
From:	Steve Roe and Brad Strode
CC:	Tom Peterson, Jeff Wennberg, Randy Strait, Sandra Meier
Subject:	Assumptions used in the quantification of options for the AFW Technical Work Group
Date:	July 12, 2010

This memorandum summarizes methods, data sources, and key assumptions to be used to estimate the GHG reductions and costs for AFW sector mitigation options. The information presented here builds on the general approaches and data sources laid out in the overview quantification memorandum covering all sectors (including common emission factors, cost assumptions, etc.).

Quantifying reductions of GHG (particularly future reductions) is an inherently complex process and assumptions are important inputs into the quantification methodologies and models used to estimate mitigation costs and benefits. Models are representations of reality, and require the best available data on likely futures. An emphasis should be placed on using assumptions that are based on the best available data using local or regional data (when available) rather than national level data.

CCS has developed estimates of GHG emissions and forecasts for the AFW sector to supplement the inventory prepared by DEC (which primarily covered combustion sources). These inventory and forecast data are needed to support the development of mitigation cost curves and to provide context to the selection of mitigation priorities. For emission inventories previously developed by CCS, the only sector for which consumption-based emissions data are provided is the electricity consumption sector. Other sectors of the inventory tend to only include GHG emissions that occur within the state as a result of energy consumption or other GHG emission process (e.g., methane from landfilled waste). For example, for fuel combustion in the RCI and Transportation sectors, only the emissions associated with fuel combustion are provided, not those associated with the extraction, transport, processing, and distribution of each fuel. Similarly, for waste management, only emissions associated with waste management processes in New York would be included in the inventory (e.g., landfilling, waste combustion), not those associated with production and transportation of the initial packaging or product that became a component of the solid waste stream. In addition, emissions from the management of New York waste that is exported out of state are not included.

For some mitigation options, fuel cycle emission reductions can be estimated, and it should be recognized that there are likely to be at least a portion of emission reductions that occur out-of-state as a result of in-state mitigation actions:

- Fossil fuel consumption: inventory estimates are based only on the GHG emissions associated with the combustion of each fuel; fuel cycle emission reductions are estimated using GHGs from combustion plus the embedded GHGs from extraction, transportation, processing, and distribution;
- Solid waste management: landfill methane emissions or total GHG emissions are associated only with waste combustion and decomposition for in-state managed waste; fuel cycle emission reductions include the landfill/waste combustion emissions plus those associated with production and distribution of the initial packaging or product (e.g., net difference of use of virgin materials versus recycled materials). Also, emission reductions that occur out of state from reductions in exported waste should be captured in the analysis; and,
- Biofuels consumption: for fossil fuel displacement benefits, the inventory includes only GHGs from fossil fuel combustion; fuel cycle emission reductions are estimated using the fuel cycle gasoline/diesel emission factors compared to fuel cycle biofuel emission factors (captures total GHGs from fuel production, processing, and distribution).

For the AFW Technical Work Group, CCS will estimate the in-state GHG reductions for each mitigation option selected for analysis. Where data and methods are available to do so, CCS will also specify the fuel cycle emission reductions, reporting these reductions as co-benefits. This method is based on the most recent guidance from Climate Action Plan project leaders. CCS also strives to estimate fuel cycle reductions for GHG mitigation in the other work group areas (Areas); so, it is important for the Climate Action Council to understand the ramifications of this (e.g., measurement of fuel cycle GHG reductions against a GHG forecast that is not based on fuel cycle emission estimates).

Common assumptions used in the development of mitigation options in other sectors (especially energy supply and transportation) are also used for the quantification of many AFW mitigation policy options. These could include future costs of fossil fuels, electricity consumption-based emission factors, costs for new electricity generation, and future gasoline and diesel consumption. In the discussion of common assumptions for the AFW sector in the sections below, CCS also notes instances where the AFW analysis will borrow common assumptions from other sectors. These common assumptions have been documented in the overview quantification memorandum, as well as the Area-specific memos (e.g., Power Supply and Delivery (PSD), Transportation and Land Use (TLU)).

Quantification Process

The analysis includes spreadsheet modeling techniques in which assumptions are transparent and readily accessible for review. The assumptions delineated in the following document are for the quantification of the policy options developed by the AFW Technical Work Group. This quantification of costs and CO_2 reductions entails the following steps:

- Develop <u>stand-alone</u> GHG reduction and cost estimates for each quantifiable option;
- Once completed, the stand alone options will be adjusted to reflect existing actions;
- To assess the AFW emission reductions without double-counting, it is necessary to consider overlaps and interactions within the AFW policies and measures;

- Options will be also be modified to reflect overlaps between AFW options and other Technical Work Group options. Potential interactions occur between AFW policies and measures that deploy renewable energy with PSD; Residential, Commercial, and Industrial (RCI); and TLU mitigation measures.

Common Methods, Assumptions, and Data Sources for GHG Mitigation

Forestry - Afforestation/Reforestation: Assumed Sequestration Rates and Costs

Carbon sequestered by afforestation activities is assumed to occur at the same rate as carbon sequestration in average New York state forests. Average carbon storage rates were determined based on USFS GTR-NE-343,[8] assuming afforestation activity with a forest type distribution of 70% maple-beech-birch, 15% oak-hickory, and 15% white-red-jack pine. This distribution is reflective of the average forest composition in New York and is based on the major forest types identified by USFS.[9] A 45-year project period is assumed, such that the rate of forest carbon sequestration under afforestation projects for an average acre in New York was estimated at 1.1 metric tons of carbon (tC)/acre/year (see Table E-3).

Table E-3. Average carbon sequestration rate for afforestation projects

Forest type	Assumed Distribution	tC/acre (0 year)	tC/acre (45 year)	tC/acre/year
Maple-beech-birch	70%	0.8	50.6	1.1
Oak-hickory	15%	0.8	56.2	1.2
White-red-jack pine	15%	0.8	37.1	0.8
Weighted Average				**1.1**

tC/acre = metric tons of carbon per acre. Excludes soil organic carbon pool due to the uncertainty in those estimates.

For reforestation projects, CCS would also use data from the same publication to derive an average sequestration rate. Reforestation refers to projects occurring on lands that had recently been under forest cover (such as planting projects following clear-cut harvesting).

Estimated per acre costs for afforestation in New York were obtained from Walker et al. 2007,[10] who surveyed state foresters, regional foresters, or other foresters and related specialists in the USFS, universities, and forest companies, and reported the results on a state-by-state basis. Costs include site preparation, labor, seedlings, and herbivore protection (Walker et al. 2007). Average per-acre afforestation costs in New York were estimated to be $550 for both hardwoods and softwoods. This is a one-time cost incurred in the year of planting.

[8] J.E. Smith, L.S. Heath, K.E. Skog, and R.A. Birdsey. 2006. Methods for calculating forest ecosystem and harvested carbon with standard estimates for forest types of the United States. USDA USFS Northeastern Research Station. General Technical Report GTR-NE-343. (This document is also published as part of the US DOE 1605(b) Voluntary GHG Reporting Program). See http://nrs.fs.fed.us/pubs/gtr/ne_gtr343.pdf.

[9] Carbon in United States Forests and Wood Products, 1987-1997: State-by-State Estimatesby Richard A. Birdsey & George M. Lewis. (available at http://www.fs.fed.us/ne/global/pubs/books/epa/states/NY.htm)

[10] S. Walker, S. Grimland, J. Winsten, and S. Brown. 2007. Terrestrial carbon sequestration in the Northeast: opportunities and costs part 3A: opportunities for improving carbon storage through afforestation of agricultural lands. Report to The Nature Conservancy Conservation Partnership Agreement by Winrock International, prepared with the support of the US DOE under Award No. DE-FC26-01NT41151.

Agriculture - Land Value and Conservation Easement Costs

If better information on conservation easement costs is not available for agricultural lands (e.g., historical in-state costs paid for conservation easements), the mitigation cost quantification will assume Conservation Reserve Program (CRP) annual payments as a proxy for easement costs.

CRP land annual payments for New York were projected across the mitigation period based on historical payments (see Table E-4), and is escalated to account for increased land value across the period.[11]

Table E-4. 2007 and projected CRP payments[12]

Year	CRP Enrollment (Acres)	Annual Payment (Thousand$)	Annual Payment ($/acre)	Annual Payment (revised to 2005$/acre)
2007	66,544	$4,863	$73.08	$66.29
2008	67,832	$5,040	$74.30	$67.39
2009	69,144	$5,223	$75.54	$68.52
2010	70,482	$5,414	$76.81	$69.67
2011	71,846	$5,611	$78.09	$70.83
2012	73,236	$5,815	$79.40	$72.02
2013	74,654	$6,027	$80.73	$73.22
2014	76,098	$6,246	$82.08	$74.45
2015	77,571	$6,473	$83.45	$75.69
2016	79,072	$6,709	$84.85	$76.96
2017	80,602	$6,953	$86.27	$78.25
2018	82,162	$7,206	$87.71	$79.56
2019	83,752	$7,469	$89.18	$80.89
2020	85,372	$7,741	$90.67	$82.24
2021	87,024	$8,022	$92.19	$83.61
2022	88,708	$8,314	$93.73	$85.01
2023	90,425	$8,617	$95.30	$86.44
2024	92,175	$8,931	$96.89	$87.88
2025	93,959	$9,256	$98.51	$89.35
2026	95,777	$9,593	$100.16	$90.85
2027	97,630	$9,942	$101.83	$92.37
2028	99,519	$10,304	$103.54	$93.91
2029	101,445	$10,679	$105.27	$95.48
2030	103,408	$11,068	$107.03	$97.08

[11] Under the Conservation Reserve Program (CRP), the USDA establishes contracts with agricultural producers to retire environmentally sensitive land. During the 10- to 15-year CRP contract period, farmland is converted to grass, trees, wildlife cover, or other conservation uses providing environmental benefits, including improvement of surface water quality, creation of wildlife habitat, preservation of soil productivity, protection of groundwater quality, and reduction of offsite wind erosion damages. The program also assists farmers by providing a dependable source of income. See http://www.fsa.usda.gov/Internet/FSA_File/annual_consv_2007.pdf.

[12] See http://www.fsa.usda.gov/Internet/FSA_File/annual_consv_2007.pdf

Agriculture - Tilling Practices

The reduction in fossil diesel fuel use associated with changing land use from intensive agriculture to alternative land use or practices is estimated at 3.5 gallons/acre.[13] The fuel cycle fossil diesel GHG emission factor is 12.3 tCO_2e/1,000 gallons.[14] This will be revised as needed to reflect the value assumed in the TLU section of this memorandum (i.e., based on the NYGREET model).

Agriculture – Fertilizer Application GHG Emissions and Costs

The fertilizer cost information provided in Table E-5 is taken from U.S. Department of Agriculture, Economic Research Service's U.S. fertilizer use and price information (see http://www.ers.usda.gov/Data/fertilizeruse/). A weighted price of applied nitrogen was derived from this information using the most recent data available from United States Department of Agriculture (USDA).

Table E-5. Average US price of common nitrogen fertilizers

Month/Year	Average U.S. farm prices of selected fertilizers				
	Anhydrous ammonia	**Nitrogen solutions 30%**	**Urea 45-46% nitrogen**	**Ammonium nitrate**	**Ammonium Sulfate**
Apr 2007	*$/short ton*				
	523	277	453	382	288
	N content (%)				
	82	30	46	34	21
	$/short ton nitrogen				
	638	923	985	1,124	1,371
2006	*US Consumption*				
	3,821,891	10,104,319	5,369,913	963,710	1,218,964
2006-2007	***Weighted $/short ton nitrogen***				
	862				

To predict fertilizer prices in the future, the historical growth rate for fertilizer prices was used. Nominal (unadjusted for inflation) growth in fertilizer prices between 1990 and 2007 averaged 7.96% growth.[15] However, when this figure is adjusted for inflation, this growth rate is significantly less dramatic. A growth rate for fertilizer price was used because fertilizer prices can fluctuate dramatically, and therefore holding these prices constant (in real dollars) did not

[13] Reduction associated with less intensive land use (e.g., fewer passes). The estimate is based on conservation tillage compared with conventional tillage, at http://www.conservationinformation.org/Core4Brochures/CTBrochure.pdf, accessed May 2008.

[14] Fuel-cycle emissions factor for fossil diesel from J. Hill et al., "Environmental, Economic, and Energetic Costs and Benefits of Biodiesel and Ethanol Biofuels," Proceedings of the National Academy of Sciences, 103(30):11206–11210. From the assessment used to evaluate U.S. soybean-based biodiesel life-cycle impacts. See http://www.pnas.org/cgi/content/full/103/30/11099.

[15] USDA ERS. Table 7. "Average U.S. farm prices of selected fertilizers." http://www.ers.usda.gov/Data/FertilizerUse/ Accessed 10/7/08.

seem an accurate estimate. Another option would be to tie fertilizer prices to natural gas prices, because natural gas costs make up 70 percent of all fertilizer production costs.[16] However, given the uncertainty involved in estimating natural gas prices, as well as the potential impact of price fluctuations (which will cause fertilizer prices to rise in the face of uncertainty), this method was not used.

The avoided fuel cycle GHG emissions (i.e., emissions associated with the production, transport, and energy consumption during application) were taken from Wood and Cowie.[17] The estimate provided for the U.S. (taken from West and Marland, 2001[18]) was 858 grams (g) CO_2e per kilogram of nitrogen (kgN).[19] In addition to the avoided fuel cycle emissions, land application nitrous oxide emissions also need to be accounted for. Traditionally, CCS has used information generated by the U.S. EPA's State Inventory Tool. In the absence of alternative data, CCS will use this tool to determine nitrous oxide emission estimates and the assumed emissions factor for nitrogen applied (i.e., X kg CO_2e / kgN applied). Combining these two emission factors provides a total emissions factor per kilogram of nitrogen applied.

Waste Management - Recycling Capital Costs

For other states, CCS has used a value of $129/household for recycling program capital costs, based on an analysis in Vermont.[20] CCS will research the availability of capital cost data specific to New York City and the rest of the state to determine whether more state-specific data are available.

Waste Management – Landfill and Compost Tipping Fees and Transportation Cost

Diverting waste from landfills can reduce costs by avoiding tipping fees. The average landfill tipping fee assumed to represent New York State is $45/ton.[21] Additional transportation and transfer costs are assumed to add $55 per ton to the total disposal cost. CCS will consult the AFW Technical Work Group regarding the potential growth rate of tipping fees. Tipping fees for composting facilities and recycling haulers must also be considered. Tipping fees for composting facilities can range from $15/ton to $50/ton depending on location and type of material being received. For other states, CCS has assumed a tip fee to recycling haulers of $10/ton.[22] It is to be

[16] Huang, Wen-yuan. "Impact of Rising Natural Gas Prices on U.S. Ammonia Supply." USDA. August 2007. http://www.ers.usda.gov/Publications/WRS0702/ Accessed 10/7/08.

[17] Sam Wood and Annette Cowie (2004) *A Review of Greenhouse Gas Emission Factors for Fertilizer Production* Research and Development Division, State Forests of New South Wales, Cooperative Research Centre for Greenhouse Accounting.

[18] West, T. O. and Marland, G. 2001. A Synthesis of Carbon Sequestration, Carbon Emissions and Net Carbon Flux in Agriculture: Comparing Tillage Practices in the United States. Agriculture, Ecosystems and Environment 1812, 1-16.

[19] These emission factors provide an estimate of the typical fuel cycle GHG emissions (including resource extraction, the transport of raw materials and products, and the fertilizer production processes) per unit weight of fertilizer produced (i.e., gCO_2e/kg fertilizer).

[20] P. Calabrese, Cassella Waste Management, personal communication, S. Roe, CCS, 2007.

[21] Personal communication from Resa Dimino of NYS DEC. Provided to B. Strode (CCS) via e-mail.

[22] J. Ketchum, Waste Management, personal communication with S. Roe, CCS, November 20, 2007.

assumed that recycling and composting facilities are closer to the point of generation and an incremental increase in these activities will not lead to a change in transportation costs.

Waste Management - Value of Recycled Materials

Current US market prices for recycled materials are available from the RecycleNet.[23] This service reports current prices for materials such as scrap metal and scrap plastic, as well as, curbside recyclables, including newspapers, office paper, loose waste paper, polyethylene terephthalate (PET), high-density polyethylene (HDPE), aluminum, steel cans, and glass. However, due to the large scale of variability in market prices for recycled material seen in recent years, the value of recycled materials is uncertain. DEC has indicated that NYC estimates total recycling revenues at $7 to $12 million per year.

Waste Management - EPA Waste Management Software Tools

EPA has several models that may be used to estimate GHG impacts or costs of waste management mitigation options.[24] The Landfill Gas Energy Cost Model (LFGcost-Web) estimates costs for landfill gas energy projects. The Waste Reduction Model (WARM) estimates GHG emission reductions from different waste management practices. The Landfill Gas Emissions Model (LandGEM) is a tool for estimating emissions from MSW landfills.

All AFW Sectors - Energy Consumption Emission Factors

Both fuel cycle and standard (fuel combustion) emission factors for energy consumption will be taken from the PSD and TLU quantification methods memoranda, as applicable (e.g., transportation fuels will be taken from the TLU section).

All AFW Sectors - Fuel Prices

As with emission factors above, assumptions for fuel prices will be taken from the applicable ES or TLU quantification methods memoranda.

All AFW Sectors - Electricity Capital Costs and Capacity Factors

Where these estimates are needed, they will also be taken from the PSD quantification methods memorandum.

All AFW Sectors - Renewable Incentives

Inclusion of the federal production tax credit (PTC) in the levelized cost estimates for renewables in the mitigation options analyzed needs to be considered. The federal Renewable Electricity Production Tax Credit has been around in some form since 1992 but seems to always be about to expire (currently December, 2012 for wind and December, 2013 for other renewable sources). The existing incentive for closed-loop biomass is 2.0¢/kWh. Electricity from open-loop biomass, landfill gas, and municipal solid waste resources receives a 1.0¢/kWh credit.

[23] RecycleNet Spot Market Pricing, http://www.scrapindex.com/index.html.

[24] EPA Waste Management Tools, http://www.epa.gov/cleanenergy/energy-programs/state-and-local/by-topic/waste.html.

PSD Common Assumptions Memorandum - Draft

To: NYS Power Supply and Delivery Technical Workgroup

From: Bill Dougherty and Jeff Wennberg

CC: Tom Peterson, Randy Strait, Jared Snyder, Carl Mas

Subject: Assumptions used in the quantification of options for the PSD Technical Work Group

Date: August 4, 2010

This memo outlines proposed data sources used to quantify the greenhouse gas (GHG) impacts and costs for those PSD Technical Work Group policy options that are considered amenable to quantification. The memo will be reviewed in an upcoming Technical Work Group call so that comments on the assumptions may be made and alternative data sources recommended for Technical Work Group approval. Any changes to this memo will be incorporated and the revised memo will be used as documentation for the modeling results.

The scope of this memo only covers the major assumptions directly related to the quantification of the PSD policy options. Recall that the emissions reductions and costs in the quantification of the policy options occur against the backdrop of the GHG forecast that includes recent state actions. The effects of the policy options are therefore incremental to the activity projected under the forecast. The assumptions embedded in the New York Inventory and Forecast were reviewed during a PSD Technical Work Group call held early in the process.

Quantification Process

The analysis includes spreadsheet modeling techniques in which assumptions are transparent and readily accessible for review. The assumptions delineated in the following document are for the quantification of the priority policy options developed by the PSD Technical Work Group.

This quantification of incremental costs from the introduction of GHG mitigation options and their corresponding CO_2e reductions entails the following steps:

- Establish the levelized cost and GHG emission characteristics of the appropriate power supply resource(s) in the Baseline GHG forecast that would be displaced by the technologies in each priority GHG mitigation policy.
- Develop stand-alone levelized cost estimates for each technology included as part of a quantifiable policy option. Some policies might require that CCS evaluate different scenarios (e.g., renewable resource mix). This will be approached on a case-by-case basis through Technical Work Group-generated design of sensitivity analyses.
- Estimate the incremental costs and GHG reductions for each stand-alone policy.

- After the stand-alone analysis is complete, perform an integrated supply/demand analysis for the PSD sector that accounts for overlaps and any potential double counting among PSD, RCI, TLU, and AFW policies. To account for the issue of credit associated with emission reductions, we propose to start with the Mitigation Case demand forecast, then develop a GHG Mitigation Case capacity expansion plan to meet that demand. This implies a RCI-PSD option analysis sequence and seems most consistent with the way expansion plans would be developed, given demand foresight.

PSD Baseline

An understanding of the Baseline capacity expansion plan, annual electricity generation and associated GHG emissions will be based on the New York State GHG Emissions Forecast developed by NYSERDA (2009). Electricity transmission and distribution losses are estimated at 9 percent on average, based on modeling work done by NYSERDA and the New York Independent System Operator[25], and are assumed to be constant across all regions. As the Baseline forecast is only available through 2018, a linear extrapolation will be made out to the end of the analysis period (i.e., 2030) consistent with an assumption that the system emissions intensity rate (i.e., tCO_2e/MWh) for the 2019-2030 period is the same as the 2018 level. Technical supporting documents for the Baseline forecast (i.e., technology performance assumptions, fuel prices, capacity additions, etc) have been provided by NYSERDA and will be used to better understand the Baseline modeling outputs.

PSD Mitigation

Electricity generation from GHG mitigation technologies are calculated at the technology level and aggregated up based on the policy design. For instance, the electricity produced by renewable sources in the Renewable Portfolio Standard are estimated based on the stipulated resource mix relative to the mix of fossil resources that would be displaced in the Baseline. An assessment of the mix of fossil resources displaced in the Baseline will be made on a policy-by-policy basis in consultation with NYSERDA and the Technical Work Group.

Cost Assumptions

The incremental costs to implement the PSD options are the difference between the levelized costs of GHG mitigation options and the levelized costs of the resources displaced in the Baseline. The assumptions associated with costs calculations are:

- Forecasted fossil fuel prices for the PSD sector and well as technology cost and performance assumptions will be consistent with those used to develop the Baseline power supply forecast.
- Forecasted technology cost and performance assumptions for GHG mitigation options will be consistent with those used to develop the NYSERDA Cost Curve study. These will be augmented/adjusted as needed in consultation with NYSERDA and the Technical Work Group.

[25] Personal communication with Ted Lawrence at NYSERDA on November, 12, 2008.

Electricity Imports

The GHG emissions associated with electricity imports assumes that the emissions intensity over the analysis period is a constant 0.36 metric tons CO_2/MWh on a consumption basis. This is based the State Energy Plan "starting point" generation, demand, and GHG forecasts. It is assumed that cost impacts associated with changes in electricity imports are based on the annual wholesale electricity prices.

Effects of Recent Actions

Relevant recent actions that are not included in the NYSERDA forecast will be accounted for to the extent possible. We assume that the effects of the Renewable Portfolio Standard are included in the NYSERDA electricity and fuel forecasts. It is important to note that the 'Starting Point' only includes the 25 percent RPS. The 45 by15 policy is a bit complicated in that the new 30% RPS is linked to a reduction in load leading to an output where new renewable generation is not much larger. The existing Integrated Planning Model (IPM) runs for the different cases will be reviewed to assess the prospects for a parameterized analysis (i.e., no new IPM runs). In any event, this issue will be further discussed with NYSERDA as the quantification gets underway.

Other Assumptions

The following assumptions are generic to all options:

- Real discount rate: costs and benefits from each option are discounted at a 5 percent real discount over the 2011-2030 period as specified by the Climate Action Plan Quantification Methods Memorandum.
- GHG emission factors: Fuel-based emissions factors are as specified by the Climate Action Plan Quantification Methods Memorandum.
- Technological Change: The impacts of technology learning on capital costs of PSD technologies will be folded into the levelized cost calculations consistent with assumptions developed in the NYSERDA Cost Curve study. The ongoing NYSERDA review of solar-PV price forecasts should be completed by the time the quantification gets underway. In addition, we will aim to incorporate any recommended assumptions from the EPRI review of the Cost Curve study.

Moreover, the quantification of each of the PSD policy options requires additional assumptions that are germane to each option. These are identified in the design for each option and will be incorporated into the analysis in consultation with NYSERDA and the Technical Work Group.

RCI Common Assumptions Memorandum - Draft

To: NYS Climate Action Plan Residential, Commercial/Institutional and Industrial Technical Workgroup

From: Hal Nelson and Steve Bower

CC: Tom Peterson, Jeff Wennberg, Randy Strait, Karen Villeneuve, Jodi Smits-Anderson

Subject: Assumptions used in the quantification of options for the RCI Technical Work Group

Date: July 26, 2010

This memo outlines proposed data sources used to quantify the greenhouse gas (GHG) impacts and costs for those RCI Technical Work Group policy options that are considered amenable to quantification. The memo will be reviewed in an upcoming Technical Work Group call so that comments on the assumptions may be made and alternative data sources recommended for Technical Work Group approval. Any changes to this memo will be incorporated and the revised memo will be used as documentation for the modeling results.

The scope of this memo only covers the major assumptions directly related to the quantification of the RCI policy options. Recall that the emissions reductions and costs in the quantification of the policy options occur against the backdrop of the inventory and forecast. The effects of the policy options are therefore incremental to the activity projected under the inventory and forecast. The assumptions embedded in the New York Inventory and Forecast were reviewed at during the February 5th, 2010 RCI Technical Work Group call.

Quantification Process

The analysis includes spreadsheet modeling techniques in which assumptions are transparent and readily accessible for review. The assumptions delineated in the following document are for the quantification of the policy options developed by the RCI Technical Work Group. This quantification of costs and CO_2 reductions entails the following steps:

- Develop <u>stand-alone</u> cost estimates for each quantifiable option
- Once completed, the stand alone options will be adjusted to reflect <u>existing actions</u> such as the NYS energy efficiency portfolio standard and the April, 2010 customer sited renewable portfolio standard. These are actions that are not in the reference case forecast, but are likely to occur. Adjusting for existing actions eliminates potential "double counting" of greenhouse gas reductions.

- To assess the RCI emission reductions without double-counting, it is necessary to consider overlaps and interactions within the RCI policies and measures as they affect similar types of energy use.
- Options will be also be modified to reflect overlaps between RCI options and other Technical Work Group options. Potential interactions occur between RCI policies and measures that deploy renewable energy with Power Supply and Delivery (PSD) and Agriculture, Forestry and Waste (AFW) mitigation measures. One interaction that could be modeled is the effect of New York's renewable portfolio standard (RPS) and the Power Supply and Delivery policy options on the assumed carbon intensity of electricity delivered to the RCI sectors.

RCI Energy Reductions

Energy savings from efficient technologies and best practices are calculated at the technology level and aggregated up based on energy consumption at the relevant end use. For instance, the electricity savings from light emitting diode (LED) technologies are estimated based on the incremental energy efficiency of LED lighting over the assumed reference technology. These energy savings are then adjusted for lighting energy use as a percent of the RCI sectoral sales, less business as usual LED penetration. Electricity savings are also adjusted for transmission and distribution (T&D) losses according to the formula:

> *Eq 1). Annual energy efficiency deployment: [(technology or practice electricity savings) / (1-T&D losses)]*

Annual baseline energy consumption and GHG emissions will be derived from the most recent NYSERDA NYS GHG Emissions Inventory.

- The baseline electricity demand comes from the "starting point" forecast for RCI sectors through 2030.
- The fuel consumption forecast comes from most recent NYSERDA forecast.

Electricity T&D losses are estimated at 9 percent based on modeling work done by NYSERDA and the NY Independent System Operator[26]. Electricity T&D losses are assumed to be constant across all regions and load periods even though peak electricity T&D losses are higher than baseload T&D losses. Natural gas T&D losses are not initially accounted for as energy savings from avoided natural gas transmission and distribution usage are assumed to be modest. The GHG benefits from reduced gas demand will be discussed qualitatively, but if quantification of policies to conserve natural gas show significant reductions, then avoided fugitive methane emissions might be estimated.

Methodology for Avoided Carbon Dioxide (CO_2) Calculations

Energy reductions for fuel in physical units (Btu) will be converted into GHG emissions reductions according to their relevant emissions factors presented in the quantification methods memorandum. For electricity reductions, the GHG impacts for grid connected RCI policy options are quantified according to the following formula:

[26] Personal communication with Ted Lawrence at NYSERDA on November, 12, 2008.

*Eq 2). CO_2 Reductions in year$_t$: Electric efficiency deployment (GWh) in year$_t$ * CO_2 intensity in tons per GWh in year$_t$*

To estimate emissions reductions from policy options that are expected to displace conventional grid-supplied electricity (i.e., energy efficiency) a straightforward approach is employed based on input from NYSERDA and other stakeholders. Consumption-based emission intensity has been developed that accounts for emissions from imported power, instate generation as well as CO_2 emissions from transmission and distribution losses. A weighted average approach to instate generation and imports was employed based on the State Energy Plan "starting point" generation, demand, and GHG forecasts. Imports over the period were credited at 0.36 metric tons CO_2 / MWh for all periods. The consumption based intensity divides CO_2 emissions from the power sector by electricity demand (instead of generation).[27] Due to reductions in forecasted T&D losses as well as increased penetration of renewables and other lower carbon fuels, the forecasted emissions intensity in metric tons CO_2/MWh is forecasted to decline dramatically in NY in the near term. The following table shows the electricity emissions intensity assumptions employed:

Table E-6: Consumption-Based Electricity Emissions Intensity [2009 PLACEHOLDER]

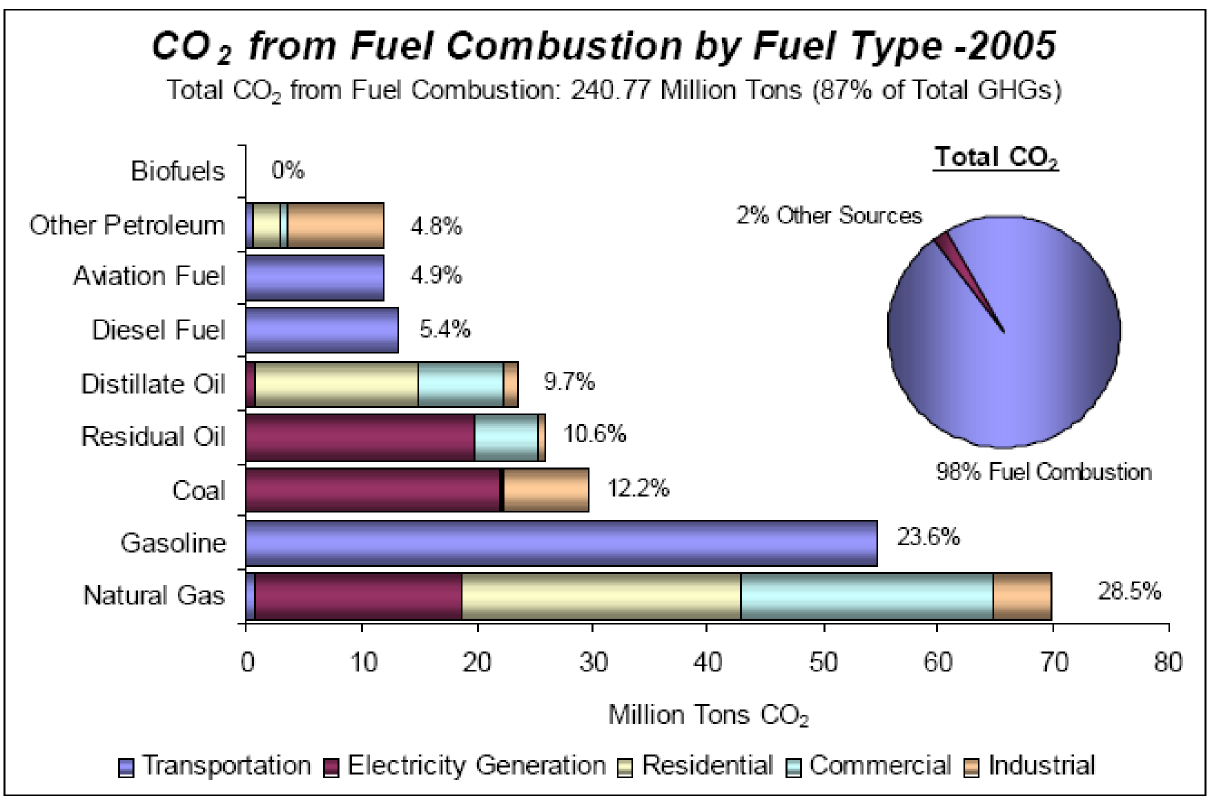
Year	Tonnes CO_2 / MWh
2006	0.42
2007	0.38
2008	0.35
2009	0.33
2010	0.31
2011	0.31
2012	0.30
2013	0.30
2014	0.30
2015	0.29
2016	0.29
2017	0.29
2018	0.29
2019	0.29
2020	0.29
2021	0.29
2022	0.29
2023	0.29
2024	0.29
2025	0.29

[27] The consumption based approach is slightly higher than the production based intensity. The consumption based approach makes more sense from a theoretical standpoint as emissions from T&D losses are mitigated from RCI end user activities.

Year	Tonnes CO_2 / MWh
2026	0.29
2027	0.29
2028	0.29
2029	0.29
2030	0.29

Current electricity load forecasts are available through 2030.
This approach provides a transparent way to estimate emissions reductions and to avoid double counting (by ensuring that the same megawatt hours (MWh) from a fossil fuel source is not "avoided" more than once). It can be considered a "first-order" approach; it does not attempt to capture a number of factors such as the distinction between peak, intermediate, and baseload generation; issues in system dispatch and control; impacts of nondispatchable and intermittent sources such as wind and solar; or the dynamics of regional electricity markets. These relationships are complex and could mean that policy options affect generation and emissions (as well as costs) in a manner somewhat different than estimated here. Nonetheless, this approach provides reasonable first-order approximations of emissions impacts and offers the advantages of simplicity and transparency that are important for stakeholder processes.

Figure E-2. 2005 CO_2 Emissions in New York State



Cost Assumptions

The cost to implement the RCI options are the net difference between the avoided costs of energy and the cost of the energy efficiency measures where:

*Net costs (benefits): Energy efficiency deployment * (avoided cost of energy – levelized cost of measures including administrative costs)*

The assumptions associated with costs calculations are:

- Forecasted fuel prices for the RCI sectors come from the most recent NYSERDA price forecast.
- Avoided electricity prices from Optimal (2010) for the RCI sectors are used for avoided costs and are estimated in the following manner:
    - For each year following the end of the available forecast period, the prices are changed by the annual forecasted change in price of electricity from table 67 of the detailed outputs to the AEO 2010 for the NERC region.[28]

Effects of Recent Actions

Relevant recent actions that are not included in the NYSERDA forecast will be accounted for to the extent possible. The federal Energy Independence and Security Act (EISA) of 2007 was signed into law in December 2007. This law contains several requirements that will reduce GHG emissions as they are implemented over the next few years. We assume that the effects of the EISA are included in the NYSERDA electricity and fuel forecasts.

Relevant updates to New York's mandatory building energy codes are also identified in the analysis. NYS' residential code is based on the 2004 International Code Council's International Energy Conservation Code (IECC). For commercial buildings New York references the 2003 IECC code and American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) 90.1 standards.

Planned activities such as the NYS Energy Efficiency Portfolio Standard (EEPS) 15% efficiency target by 2015 (45 by 15), as part of the Governor's proposal to have 45% of electricity come from renewables and energy efficiency, will be explicitly modeled as appropriate.[29] The April 2nd, 2010 RPS order will be included as a recent action "wedge" between what would have happened in the baseline through 2015 and the Climate Action Plan policies.

Evolving policies with market-driving effects such as the governor's Executive Order 111 for state buildings, which ends in 2010, New York City legislation in response to the Mayor's PlaNYC2030, and other currently planned energy efficiency interventions by NYSERDA, Long Island Power Authority (LIPA), and New York Power Authority (NYPA) will be analyzed, as

[28] http://www.eia.doe.gov/oiaf/archive/aeo08/index.html

[29] A scenario with the effects of the 15% energy efficiency savings by 2015 is estimated as the difference between the "starting point" load forecast and the 15x15 in the most recent forecast file.

budget and project time allow, to assess baseline penetration rates of selected efficiency measures.

Other Assumptions

The quantification of each of the policy options requires additional assumptions that are germane to each option and are described in detail in the policy option document. For instance, there are many building code assumptions in that policy option. However, the following assumptions are generic to nearly all options:

- Real discount rate: costs and benefits from each option is discounted at a 5 percent real discount over the 2010-2030 period as specified by the NY Climate Action Plan Quantification Methods Memorandum.
- Technological Change
    - An examination of historical energy efficiency equipment, including compact florescent lights, solar PV, heat pump water heaters, and other measures shows learning curves that result in capital cost reductions over time. The installed costs and value of energy savings are sensitive to future conditions. Learning curves will be used for selected measures to account for economies of scale in production which result in cost reductions over time. Learning curves will come from the most recent, reliable data sources.

TLU Common Assumptions Memorandum - Draft

To:	New York Climate Action Council
From:	Hillel Hammer
cc:	Tom Peterson, Jeff Wennberg, Randy Strait, Sandi Meier, Ernest Tollerson and Paul Beyer
Subject:	Analysis and Assumptions for Transportation and Land Use Policy Options
Date:	July 12, 2010

This memo summarizes key elements of methods of analysis aimed at estimating potential greenhouse gas (GHG) emission reductions and cost effectiveness of Transportation and Land Use (TLU) policy options in the New York State Climate Action Plan process. The process of policy analysis is intended to support state-specific design and analysis of draft policy options, while providing for both consistency and flexibility.

Key general guidelines for policy analysis as conducted by Center for Climate Strategies' consultants are presented first, followed by specific elements of policy analysis methods and assumptions for Transportation and Land Use issues.

1. GENERAL GUIDELINES FOR POLICY ANALYSES

The following outlines the central guidelines for policy analysis. For a complete description of all general guidelines for policy analysis, see *Draft Quantification Methods Memorandum—New York State Climate Action Plan*, July 2010 ('Quantification Memo').

Fuel Cycle Coverage

GHG reductions for each mitigation option in TLU will be based upon the full fuel cycle because information is available to support this type of analysis for this sector (see more in Section 2 below).

Life Cycle Coverage

As mentioned above, there are other mitigation policy options that will also have important life cycle impacts. These include those associated with reducing non-fuel consumables, such as concrete and steel. Life cycle impacts will be reported for each source for which information is available to support a life cycle analysis. For TLU, this will focus mostly on construction materials, where possible. It will not be possible to identify in-State versus out-of-state sources for these construction materials.

Pollutant Coverage and Global Warming Potentials

The analysis will cover the six Kyoto GHGs, presented as carbon dioxide equivalent (CO_2e), which indicates the relative contribution of each gas to global average radiative forcing. This will be based on the approach outlined by the Intergovernmental Panel on Climate Change (IPCC) in its Second Assessment Report, consistent with the draft GHG emissions inventory and forecast for the state of New York and with the U.S. Environmental Protection Agency (EPA) and IPCC guidance.

Time Period of Analysis

For each sector, life cycle emission reductions and incremental life cycle costs will be calculated relative to the characteristics of the Baseline that would otherwise prevail in New York up through the end of the planning period, 2030.

The analysis will report annual emission reductions for 2020 and 2030. The net present value of the cumulative costs, and cumulative emission reductions, will be reported for the period starting with the initial year of the phase-in of the policy, up through 2030. For long-term capital investments, the investment will be annualized over the lifetime of the project operation, and the portion included in the analysis period will be included.

Transparency

Analyses will be performed in spreadsheet format to the extent practicable, to enable maximum transparency and facilitate review. Exceptions to this will be only in cases where external models such as GREET are required (see details on the model in Section 2).

Data sources, methods, implementation mechanisms, key assumptions, and key uncertainties will be documented and supported by references to provide transparency on how the key analytical outputs for each policy option were developed and applied. Information provided by the state agencies and project participants will be used to ensure best available data sources, methods, and key assumptions using their expertise and knowledge to address specific issues in New York State. Modifications will be made through facilitated discussions.

Key Analytical Outputs and Metrics

GHG Emission Reductions

Net GHG reduction potential in physical units of million metric tons (million metric tons or MMt) of carbon dioxide equivalent (CO_2e) will be estimated for each quantifiable policy for target years 2020 and 2030, as well as the total for the entire analysis period.

Costs

Net capital, operating and maintenance (O&M), and fuel costs will be estimated for each of the policies that are determined quantifiable. Costs will be discounted as a multi-year stream of net costs to arrive at the "net present value cost" associated with implementing new technologies and best practices. It is proposed that costs be discounted in constant 2005 dollars using a 5 percent annual real discount rate. The nominal discount rate will be calculated by adding the projected inflation rate over the analysis period. Capital investments will be represented in terms of annualized or amortized costs over the project period. (See the section on "Cost Analysis Methods" for additional details.)

Cost savings (e.g., fuel savings) will be included, represented as a negative cost. If significant financing costs or split incentives (cases where the benefits are not reaped by the investor) are expected, these will be identified.

Cost-effectiveness

The cost effectiveness—cost or savings per tone—for each quantified policy, represented as dollars per MMt CO_2e (\$/MMtCO_2e), will be calculated by dividing the present value cost by the cumulative (undiscounted) reduction in GHG emissions. When combined with GHG impact assessments, the results of these cost estimates will be aggregated into a sectoral summary table and sector and economy-wide stepwise marginal cost curves.

Direct vs. Indirect Effects

"Direct effects" are those borne by the entities subject to or directly affected by the policy or entities implementing the new policies. For example, direct costs are net of any financial benefits or savings to the entity. Direct effects will be quantified.

"Indirect effects" are those borne by entities other than those defined for "direct effects". Indirect effects will not be quantified.

Non-GHG (External) Impacts and Costs

Environmental co-benefits such as reductions in criteria air pollutants, which in turn would lead to reduced public health impacts from productive activities in New York, will not be quantified. Qualitatively, CCS will document measures that are expected to have other non-GHG impacts, including, but the physical and monetary costs or savings associated with these external impacts will not be included explicitly in this analysis.

Uncertainty / Sensitivity Analysis

Key uncertainties and feasibility issues will be identified and discussed qualitatively.

Calculation of Emissions

Emission reductions will be estimated incremental to baseline emissions based on the change (reduction) in emissions activity (e.g., reduced vehicle miles traveled—VMT), calculated either directly, by using the same factors applied in the baseline inventory (e.g., reduction in fuel consumed and fuel-based emission factors), or as a fraction of the baseline inventory (e.g., fraction of baseline VMT and associated emissions reduced).

Emissions associated with electricity consumption will be calculated based on the procedures outlined for the PSD sector. Electric demand by vehicles may be calculated using the NY-GREET model (see Section 2 below).

Calculation of Costs

Net capital, operating and maintenance (O&M), and fuel costs will be estimated for each of the policies that are determined quantifiable. Costs will be discounted as a multi-year stream of net costs to arrive at the "net present value cost" associated with implementing new technologies and best practices. It is proposed that costs be discounted for all options in constant 2005 dollars using a 5 percent annual real discount rate. The nominal discount rate will be calculated by adding the projected inflation rate over the analysis period.[30] For full details on cost calculation, see the Quantification Memo.

Documentation

Documentation of the work will be completed in a template format that addresses the following items (among others):

Work Group Sector

Name of policy option

Policy Description

Policy Design (Goals and Timing for implementation and parties involved or affected by implementation of the policy.)

Implementation Mechanisms

Quantification: Estimated GHG Savings and Costs per MtCO2e (GHG reduction potential in 2020 and 2030, Cumulative GHG reduction potential, net cost, data sources, and quantification methods)

Key Assumptions and Uncertainties

Co-Benefits and External Costs (qualitative discussion)

POLICY ANALYSIS METHODS AND ASSUMPTIONS SPECIFIC TO TRANSPORTATION AND LAND USE ISSUES

Policy analysis of transportation and land use issues is inherently complex, given the inter-relationships between transportation systems, land use, and other important aspects of societal well-being. Policy analysis methods for transportation and land use as conducted by consultants for CCS is based upon many years of well-established professional practice and methods that are widely accepted in the fields of public policy analysis, urban and transportation planning, transportation engineering, and environmental sciences. The information provided here provides information about analyses relating to the potential changes in GHG emissions in the transportation sector resulting from the combustion of transportation fuels and use of electric power. In addition, GHG emissions associated with the production and transport of standard and alternative fuels ('fuel-cycle emissions') and with construction activity and materials are included where information and methods are readily available.

There are four general categories of factors that impact upon the emission from the transportation sector: vehicles, fuels, systems, and travel activity. These four factors interact in a complex

[30] The inflation rate for the analysis period is assumed to be 2.2%, subject to approval by the Integration Advisory Panel and Climate Action Council. Capital and other costs reported in nominal dollars will be converted to 2005$ using the inflation rate for the NY state region as reported by the Bureau of Labor Statistics (http://www.bls.gov/ro2/news.htm)

fashion to affect GHG emission. In addition, direct and indirect emissions may be associated with construction and infrastructure.

Underlying Premises and Methodology

Simple spreadsheet modeling techniques in which assumptions are transparent will be used for the analyses as much as possible. To ensure consistent results across options, common factors and assumptions will be used for the following items:

Independent and integrated analyses: Each option will first be analyzed individually and then addressed as part of an overall integrated analysis.

Fuel Costs and Projected Escalation: Fuel cost estimates will be based on common sources wherever possible. For example, fossil fuel price escalation will be indexed to the U.S. Department of Energy (DOE) projections as indicated in their most recent Annual Energy Outlook (AEO).

Consumption–Based Approach: The analysis uses a consumption-based approach where emissions are calculated on the basis of the consumption of transportation fuels (represented as direct fuel consumption or as vehicle miles traveled) to provide energy to New York consumers, as opposed to a production-based approach, which considers the emissions from in-state production of transportation fuels.

Life cycle Emissions: Life cycle greenhouse gas emissions are considered on a case-by-case basis. The primary focus of the analysis of Transportation and Land Use issues is upon the direct combustion of transportation fuels to provide energy. Energy cycle of fuels will be included, and construction impacts will be included where practicable.

Overlap with Other Sectors: Where TLU options overlap with options being considered in other Technical Work Groups, the analysis for these options will be conducted in close coordination with the assumptions and other inputs used in other CCS analyses.

Data Sources

TWG members are often in a good position to obtain and provide data sources that are specific to New York, and these will be used as much as possible, including data already provided by NYSDOT, MTA, and others. Where New York-specific information cannot be readily obtained from the Technical Work Group, the analysis relies on other local data available to the consultants, and on published data from the DOE, EPA, national laboratories, other federal agencies, and other state climate change processes.

The analysis of renewable fuels and the use of electricity for vehicles will be based on output from the New York-specific application of the Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model (NYGREET), prepared for this effort (also used in the baseline inventory).

General data sources will include:

Baseline Historical Energy Consumption by Sector

Historical energy consumption in the state, by sector, is from the DOE Energy Information Administration (EIA) State Energy Data available at http://www.eia.doe.gov/emeu/states/seds.html.

Baseline Historical Vehicle Fleet, Fuel Use, and Travel Activity Data

Baseline data on the state vehicle fleet, fuel use, and travel activity data is obtained from the latest inventory and forecast provided by NYSERDA. (Data sources, and methods of analyses for the baseline and forecast are described in the inventory and forecast.)

Baseline Forecast GHG Emissions

Baseline forecasts of future GHG emissions for the transportation and land use sector is obtained from the inventory and forecast report.

Energy Price Projections through 2030

Energy prices by region are from the EIA Supplemental Tables to the AEO 2010, with projections through 2030. Adjustments to the EIA projections are made on a case-by-case basis.

Cost Inclusion

The analytical methods being used can incorporate a wide variety of costs, depending on the availability of cost data. Fuel costs are incorporated into all analyses where relevant. Other types of costs will be explicitly considered in the analysis if they can be readily estimated. Types of costs that may be incorporated include:

Annualized Capital costs levelized (amortized);

Operations and maintenance cost; and

Administrative costs.

Types of costs that will not be incorporated include

External costs, such as the monetized environmental or social benefits and impacts (e.g., the cost of damage by air pollutants on structures and crops), quality-of-life improvements, and health impacts and benefits (e.g., improved road safety);

Energy security benefits; and

Macroeconomic impacts related to reduced or increased consumer spending, and shifting of cost and benefits among different sectors of the economy.