NYS SmartGrid Consortium

NYS Smart Grid Roadmap

Prepared for the New York State Smart Grid Consortium

Presented at NYS Smart Grid Consortium
Board of Directors Meeting
August 5, 2010

Our Objective

To assess broad economic, customer and social impacts to NYS from the aggressive deployment of "Smart Grid" Technologies

This unique statewide analysis factors in all practical Smart Grid technologies and applications, and considers all the potential consequences over the next decade.

Contents

Background

- This report is a roadmap for Smart Grid deployment in New York State. It attempts to analyze the relative costs, benefits, and priorities of the various Smart Grid technologies, business models, and policies in some detail including how different types of customers and geographic regions benefit. The report describes all of the assumptions and calculations in the analysis of full statewide costs and benefits of a New York Smart Grid, including the use of an interactive model to assess the relationships between investments and savings.

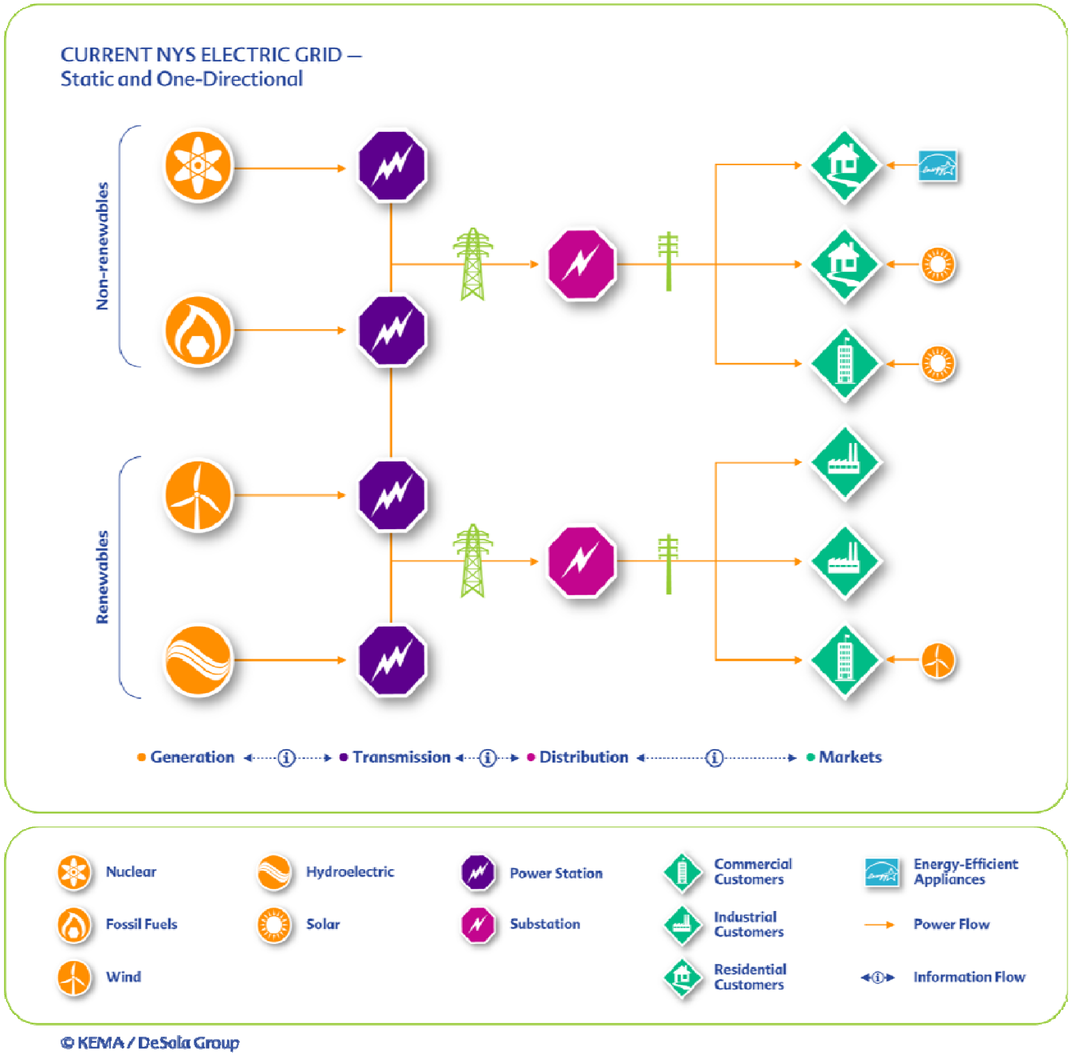
- It analyzes savings to consumers that will accrue from direct impacts on T&D rates; on energy usage and on energy market peak prices; and from other economic benefits that directly flow to consumers. It also identifies less direct benefits such as environmental impacts and economic development.

- Initial estimates of NY Benefits and Costs were presented to the Consortium in a Whitepaper, and updated data and calculations are included as an Addendum to this report. Comments and questions from members on the Whitepaper are addressed in the Addendum.

- Following the presentation of the initial Benefits and Costs, work began on the development of a Road Map for NY Smart Grid strategies. Alternative Scenarios are presented which reflect various policy decisions, levels and timing of technology deployments, in order to establish priorities for investments and to demonstrate the overall impact of different incremental choices. Some sensitivity analyses are also presented.

Current State

- The electric grid, as we currently know it, has remained relatively unchanged for the last 50+ years.
- It transports electricity from centralized points of large-scale generation sources over delivery transmission and distribution networks to consumers.
- The transmission system delivers electricity from power plants to distribution substations, while the distribution system delivers electricity from those substations to consumers.
- The flow of energy and information
is predominately static and one directional – from generators to the consumer, limiting the proactive participation of consumers.



The Vision

- "Smart Grid" means many things to many people today. It is not a "one size fits all" technology and must be adapted and configured for each region, state, and power utility.

- The Smart Grid envisions an entirely transformed electrical infrastructure. It will embody a network of devices as vast, interconnected, automated, and interactive as the Internet.

A great many diagrams and graphics portraying the Smart Grid have been published and adopted by entities such as DOE or the Grid Wise Alliance. These graphics are designed uniquely for New York by the Consortium.

The Vision *(cont'd)*

- The Smart Grid is a vision for the electric delivery system of the future.
- Smart Grid will ultimately change the nature of the relationship between consumers, state regulators and utilities for the better.

20th Century Grid	*21st Century Smart Grid*
Electromechanical	**Digital**
Very limited or one-way communications	**Two-way communications every where**
Few, if any, sensors – "Blind" Operation	**Monitors and sensors throughout – usage, system status, equipment condition**
Limited control over power flows	**Pervasive control systems – substation, distribution & feeder automation**
Reliability concerns – Manual restoration	**Adaptive protection, Semi-automated restoration and, eventually, self-healing**
Sub-optimal asset utilization	**Asset life and system capacity extension through condition monitoring and dynamic limits**
Stand-alone information systems and applications	**Enterprise Level Information, integration, inter-operability and coordinated automation**
Very limited, if any, distributed resources	**Large penetrations of distributed, Intermittent and demand-side resources**
Carbon based generation	**Carbon Limits and Green Power Credits**
Emergency decisions by committee and phone	**Decision support systems, predictive reliability**
Limited price information, static tariff	**Full price information, dynamic tariff, demand response**
Few customer choices	**Many customer choices, value added services, integrated demand-side automation**

Assumptions – High Level Summary

- The "end state" is a full statewide deployment of Smart Grid by 2025
- State Energy Plan Used as a Baseline (load growth, renewables penetration, energy prices/costs)
- Smart Grid Costs Reflect Current Filings, National Experience, and Forward Cost Projections
  - Full cost of Distribution Automation roll-out assumed w/o credit for existing DA penetration. No underground secondary network automation beyond the vaults
  - Substation Automation and Advanced Asset Management Deployed at Majority of 345 kV and 230 kV stations and selected lower voltage stations
  - AMI meters include the cost of remote connect/disconnect as requirement for future operational benefits but no usage of them is factored into the base scenario
  - Gas Meters also assumed (gas smart grid) in order to accrue Metering operational benefits and a very low gas conservation amount (1%) assumed (no data available on this subject in the US)
- Costs are incurred in 2011-2025 and benefits accrue as the technologies are deployed. Benefits after 2025 not considered.

Assumptions *(cont'd)*

- 6% EV / PHEV Penetration by 2025 (inferred from state plan). Drives Distribution CAPEX and need for Smart Charging. Fuel Costs and Environmental Benefits of EV are NOT included. Avoided/deferred distribution CAPEX and smart charging benefits are included.
- Latest reported utility Distribution Marginal Capital figures used for estimating the impact of EV penetration, smart charging, PV penetration, and Demand Response peak shaving
- Congestion savings from ability to avoid N-2 dispatch (Hudson Valley) and Gas-Oil Fuel Dispatch per discussions with NY ISO and Con Edison. Also transmission loss reductions per NY ISO publications
- Different penetrations of technologies assumed upstate and downstate
- Grid connected storage for congestion relief and renewables integration is considered as one tool in achieving these benefits; costs benefits are presented for several targeted applications.
- Initial conditions for deployment and distribution and substation are assumed; and assumptions are made about (high) levels of retail contracting for energy by C&I customers

Discussion of Assumptions

The objective is to make the baseline scenario "conservative"

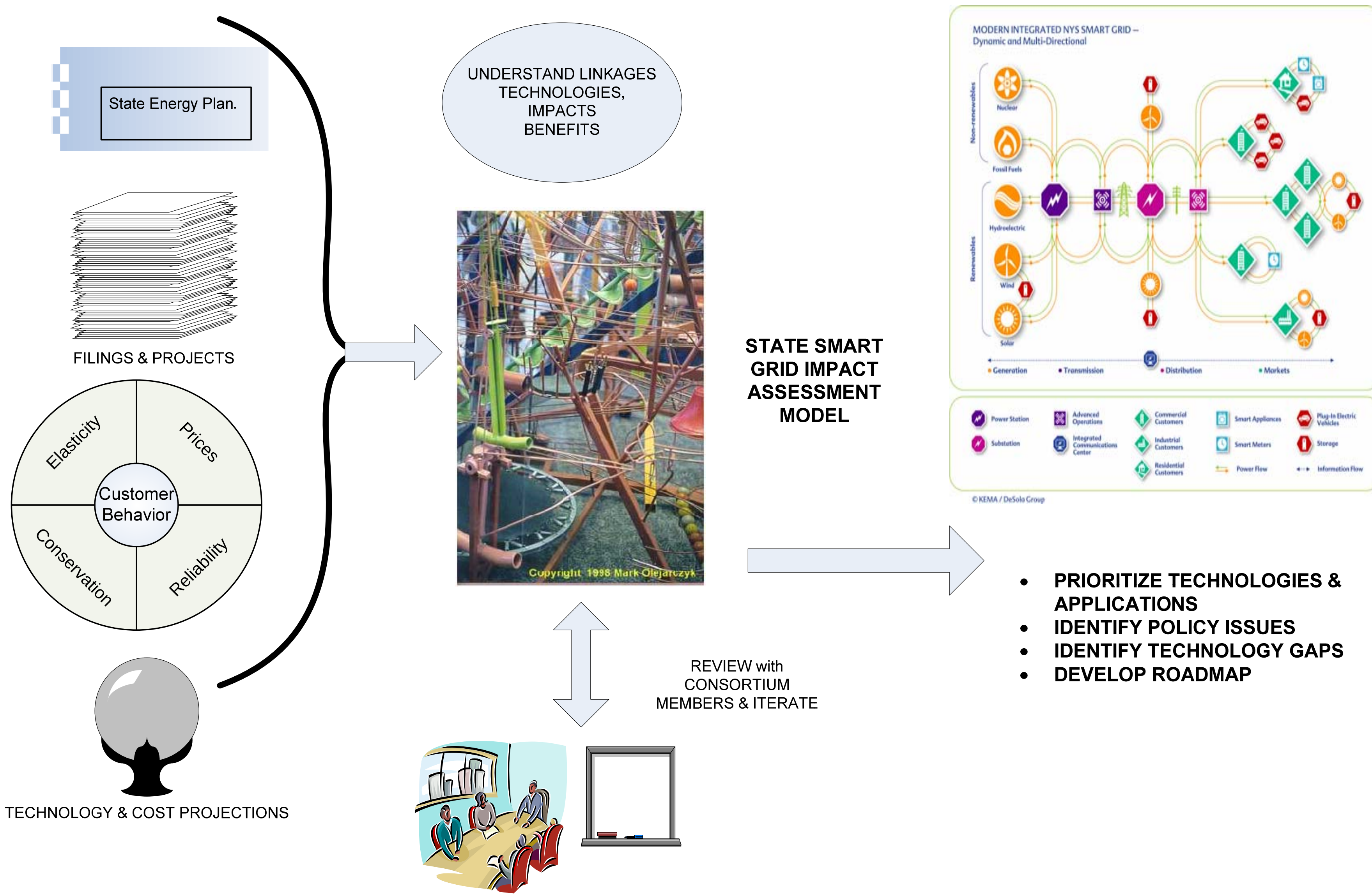
- Conservation benefits are lower than many reports or other publications
- It is necessary to include the costs of Gas Meters in order to achieve the full operational (meter reading cost reductions) of AMI. While some state utilities have "AMR" meaning drive by meter reading or other AMR, gas meters must still be read manually today.
- The benefits of using remote connect/disconnect switches are substantial in areas with high levels of rental housing and turnover, in terms of avoided trips. However, this is precluded by state policy today. (other regions appear to have lower use for these devices) The cost of the switches is included now as the cost of a later retrofit is much higher.
- The assumed conservation savings in gas usage (1%) resulting from customer information (daily usage, for instance) is low compared to reported results in the UK. (data being sought by National Grid now).
- The timing of costs and benefits are linked, and reflects a reasonable prioritization in the base case.
- The benefit/cost model allows for the definition of alternative scenarios with different timing and penetration assumptions.

Overview

The Road Map analysis is a continuation of: Benefiting New York State: An Analysis of the Economic, Customer, and Social Benefits Expected from Smart Grid Transition; New York Smart Grid Consortium; April 2010.

- This roadmap is based on the previous KEMA and DeSola Cost /Benefit whitepaper for the NY Smart Grid Consortium in 2010.
  - The original white paper assessed economics but not choices or overall timing of the installation of any Smart Grid technologies.
- This roadmap builds off that analysis by enhancing the cost / benefit analysis to include additional relationships between the parameters as well as new information obtained in review sessions with state utilities and the NY ISO.
- It also develops multiple strategic scenarios for the deployment of different Smart Grid technologies over time and in different geographic regions for different classes of customers
- The Roadmap explores the interaction of Smart Grid investments with State energy goals of carbon reduction, renewables penetration, transport electrification, and managing energy reliability, security, and prices.
- Figure 1 shows the overall process followed in developing the roadmap.
  - Information is gathered from utility filings, state agency reports, NY ISO market reports, and interviews and reviews with state utilities, the NY ISO, and other state entities.
  - Relevant information and research from other regions is used to address open questions and provide additional insight.
  - The State Energy Plan provides overall direction and goals for a future state that Smart Grid must support.
  - A technical and financial model is developed that allows exploration of the impact of different Smart Grid investment and policy decisions on state energy costs, renewable penetration, carbon reduction, and utility rate structures.
  - The model is used to illustrate how different decisions will result in different outcomes and to demonstrate the interaction of different technologies and policies.
  - From the insights gained with the model some policy directions, technology gaps, and conclusions about investment priorities are identified.

Figure 1: Roadmap Development Process



Questions the Roadmap Addresses

The Roadmap is NOT a detailed technology plan for Smart Grid statewide, nor is it a plan for any particular utility smart grid deployment. It is a higher level strategy roadmap that addresses the following questions:

1. What are the relative priorities for different Smart Grid technology deployments and business model implementations, based on their overall impact on state energy costs and goals?
2. Within those priorities, what technologies and business models are of the most value in different regions (characterized broadly as urban, suburban, and rural) within the state and to different customer classes (Residential, Commercial, and Industrial)?
3. How will the timing of different smart grid investment decisions affect overall outcomes?
4. How do customer adoption and reaction to usage information and real time prices affect overall economics?
5. What are the implications of Smart Grid investments and policy decisions on utility rates, consumer energy bills, other consumer direct financial benefits, and "soft" benefits associated with environmental impacts?
6. What are high level economic development outcomes around Smart Grid jobs creation in New York?
7. What are the implications of successful and unsuccessful programs to engage customer adoption and utilization of Smart Grid capabilities?
8. What are the implications of different approaches to dynamic pricing for different customer classes in New York?
9. How can particular New York specific transmission congestion issues be best addressed with Smart Grid technologies and business models?
10. How will Smart Grid best facilitate renewable penetration both at the grid level and distributed at the consumer level?
11. What role should energy storage play as part of a Smart Grid strategy?
12. What should state policies be with regard to Smart Charging of Electric Vehicles? What impacts will that have on the state energy plan objectives?

What We Discovered

I. Quantitative Cost / Benefit Results

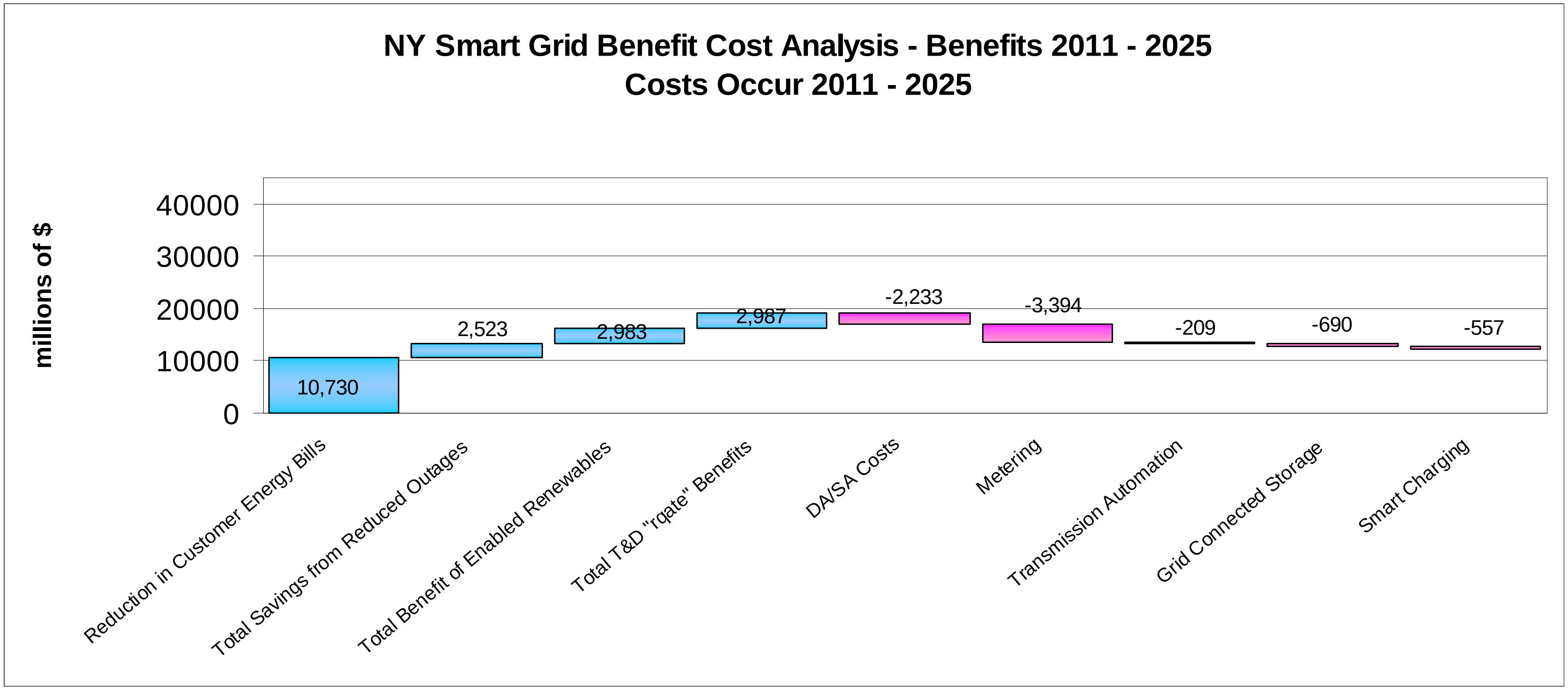
II. Customer Behavior is a Major Driver

III. Key Regulatory and Legislative Issues

IV. Other Issues

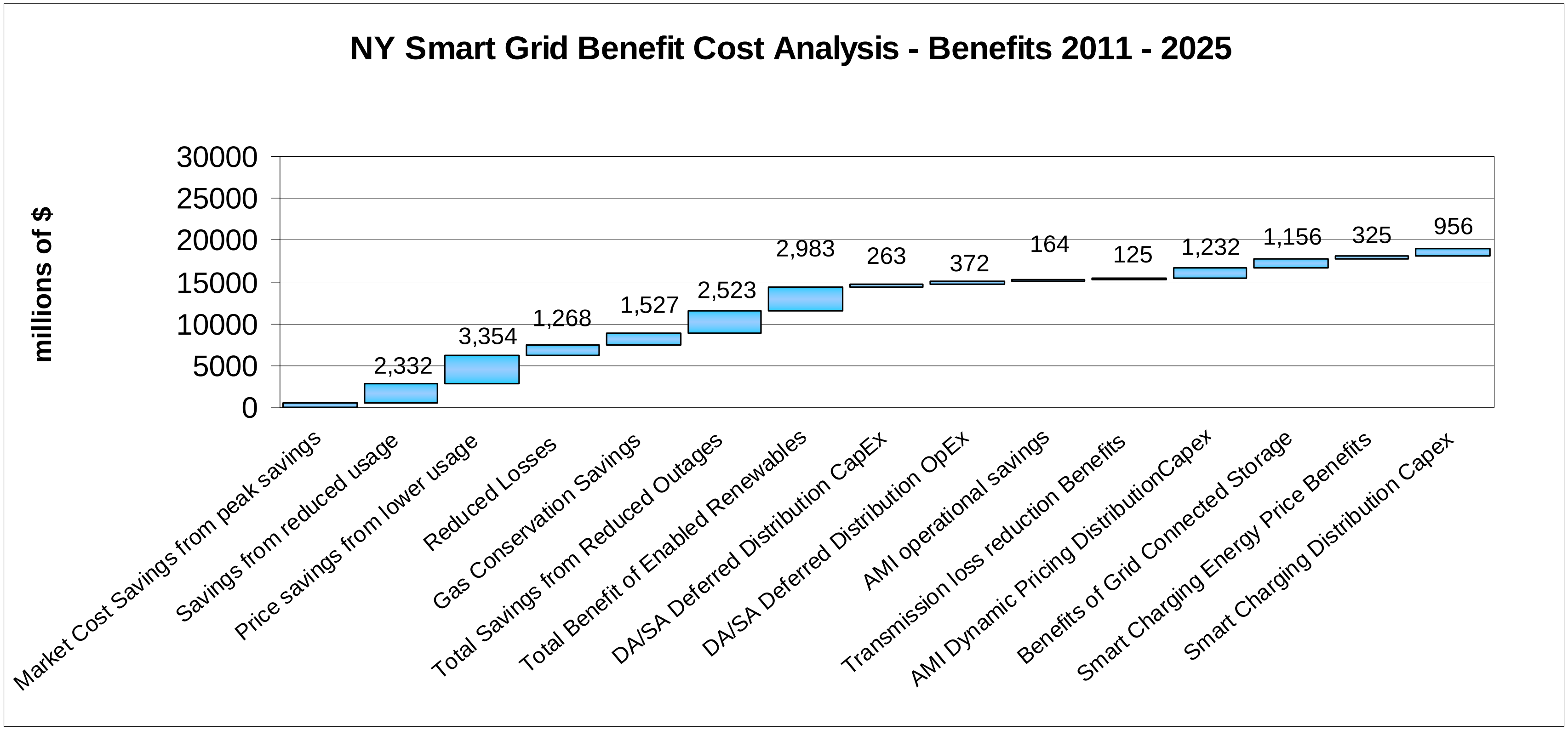
I. Quantitative Cost / Benefit Results

Base Case – High Level Costs and Sources of Benefits – Smart Grid is very cost beneficial



I. Quantitative Cost / Benefit Results

Base Case – More detail on sources of benefits- Benefits are Many and Significant



I. Quantitative Cost / Benefit Results

Total Costs (2008 $)	7,227,803
Total Hard Benefits (inflated $)	19,179,576
Benefit/Cost Ratio	3
consumer NPV	5,543,051
Hard Cash Flow	9,745,046
CB NPV	3,691,105

Direct Customer Energy Bill Savings	9,408,252
SG Benefits Rate Impact	2,567,777
Customer Bill Savings Total	11,976,029
Customer Reliability Benefits	2,293,196
Increased DER Benefits	2,703,624
Total Cash Customer Benefits	16,972,850
SG Costs Rate Impact	8,443,668
Net Cash Customer Benefit $000	9,396,518
Worst consumer cash flow in any year	-39,205

II. Customer Behavior is a Major Benefits Driver

Market Price and Conservation Benefits are Significant – these are only realized if customer usage is adaptive to incentives, time variant rates, and market prices. This will require significant customer education.

Distribution capital deferrals are driven by smart charging and to a lesser extent by other peak shifting customer usage adaptations. In order for these to be realized, there must be some planning and operational certainty around the smart charging and peak shifting.

Studies and pilots show mixed results on customer behavior changes over recent years.

- State regulatory leadership to bring the customers along is essential to realizing these benefits

III. Key Regulatory and Legislative Issues

The key regulatory and legislative Issues for Smart Grid are listed below:

- Cost Recovery of Investments
- Timing of Costs and Benefits
- Dynamic Pricing
- Cost of Education
- Smart Charging
- T&D investment to reduce Energy bill component
- Utility capture of energy price differentials on distributed storage

Clearly the cost of smart grid installation is a significant expense for the utilities of New York . To date most projects have either been pilots and or have been funded by ARRA activities. For a full scale implementation of Smart Grid in New York, the utilities will need cost recovery of appropriate expenses. Business models and policies that allow investor driven investments are desirable in some case.

Regulatory policy that allows utilities to replace aging T&D assets with “smart” (meaning smart grid enabled) assets without special rate cases under an interpretation of modernization when replacing like with like will have favorable impacts on the cost of T&D smart grid deployment.

The magnitude of the costs discussed above is upward of $7 billion. The timing of some of benefits is directly tied to the timing of the implementation. In order for customers to see the benefits the components need to be installed. The increase in rates should ideally follow the benefits.

III. Key Regulatory and Legislative Issues *(cont'd)*

Savings from dynamic pricing are a key benefit in the analysis done here. These savings will be dependent on the education of customers about how to benefit from time based pricing . The projected cost of the education is significant and to date there is limited information on the best approaches to achieving results. Voluntary opt-in schemes are explored as alternatives especially for retail customers. Determining the right level of opt in incentives and pricing for different customer classes is key to maximizing overall state benefits from customer participation in dynamic and variable pricing.

The Smart Charging and Electric Vehicle structure is evolving. Smart charging could be tied to AMI rollout. The charging of EVs could also significantly increase load on the distribution system. The integration of EVs should be done in a manner that uses off peak charging as much as possible to avoid additional CapEx.

The increased use of Distributed resources and time-based pricing will enable using these resources to defer distribution upgrades as well as just reduce energy consumption. Distribution Automation is a key Smart Grid technology for enabling distributed renewable resource adoption.

IV. Other Issues

Other issues related to Smart Grid implementation include:

- Remote Disconnect Usage to Realize Operational Savings and Provide Contingency Relief to avoid widespread network outages
- Sub metering / multiple meters at one address / EV tariffs
- Upstate versus downstate issues
- Role of 3rd party investment in customer interfaces
- Increased use of renewables and storage

In an urban environment, not all residences will have an individual meter, nor will they have a garage where electric vehicles can charge. The planning for Smart Grid charging will need to be conducted between the State, municipalities and the utilities

Upstate Consumers may not benefit as much from investments that reduce congestion charges as downstate consumers will. On the other hand, urban consumers are unlikely to see reliability improvement as a significant benefit compared to some

Another key uncertainty is who will ultimately provide the tools and or devices customers will use to control their load or energy as more time-based pricing becomes available .

The Smart Grid will enable more renewable resources and storage in the electric system. The system operator and the utilities will need to plan for this and develop the appropriate market rules.

Building a Portfolio of Investments and Alternatives

A set of baseline investments in Smart Grid was developed that is consistent with current state policies and utility activities. This baseline is described in detail later in the roadmap. At a high level, it emphasizes T&D automation technologies in the early years such as Distribution and Substation Automation, provides for Smart Charging of Electric Vehicles as such are adopted by NY consumers and businesses; and defers large investments in AMI till somewhat later. It also assumes that state policies with regard to issues such as dynamic pricing are unchanged.

From this baseline portfolio different alternatives are developed – changes in policy, changes in investment timing, and changes in overall investment decisions. These alternatives are constructed as “scenarios” and are compared to the base case both to analyze the impact of different decisions as well as to explore the underlying causes of the outcomes. The scenarios are described in detail along with their respective results later in the roadmap development.

Figure 2 [*see page 23*] shows the roadmap process as built around the construction of the baseline and the alternative scenarios.

Because a major goal of the Roadmap is to explore the implications around the timing of Smart Grid investments, the penetration rates of different technologies are critical. Some of these are “external assumptions” driven by the state energy plan (or simply as assumptions made as inputs) but others, such as the adoption of incremental Photovoltaic by consumers as a result of AMI and dynamic pricing, or the adoption of distributed storage by utilities, are based on financial penetration / adoption models as have been used in modeling distributed renewables penetration in the past. Another aspect of the Roadmap development is the use of a market price impact model developed for this effort that attempts to model how energy prices are affected by Smart Grid technologies that affect usage and peak shaving; and how those price changes translate to statewide energy cost impacts.

Building a Portfolio of Investments and Alternatives

Base Smart Grid technology penetrations, of course, are driven by the investment decisions and timing in a portfolio of investment and deployment projects that take place over the years and in different “regions” of the state, affecting (as appropriate to the technology) different customer classes.

The Scenarios developed are (at this point) somewhat stark or “black and white” - as in “No Smart Charging” . This is not because we believe that 0 and 100% alternatives are necessarily valid choices or even realistic. It is because these alternatives allow the identification of all the costs, benefits, and knock-on effects of different strategic choices. When we believe that the relationships and benefits are non-linear or complex, which is the case with market price impacts, then intermediate decisions can be made to expose further sensitivities. This is done, for instance, in the case of dynamic pricing adoption for different customer classes.

At an abstract high level, the relationship of Smart Grid technologies to categories of benefits is shown in Figure 3 *[see page 24*].

Figure 2: Overall Roadmap Process

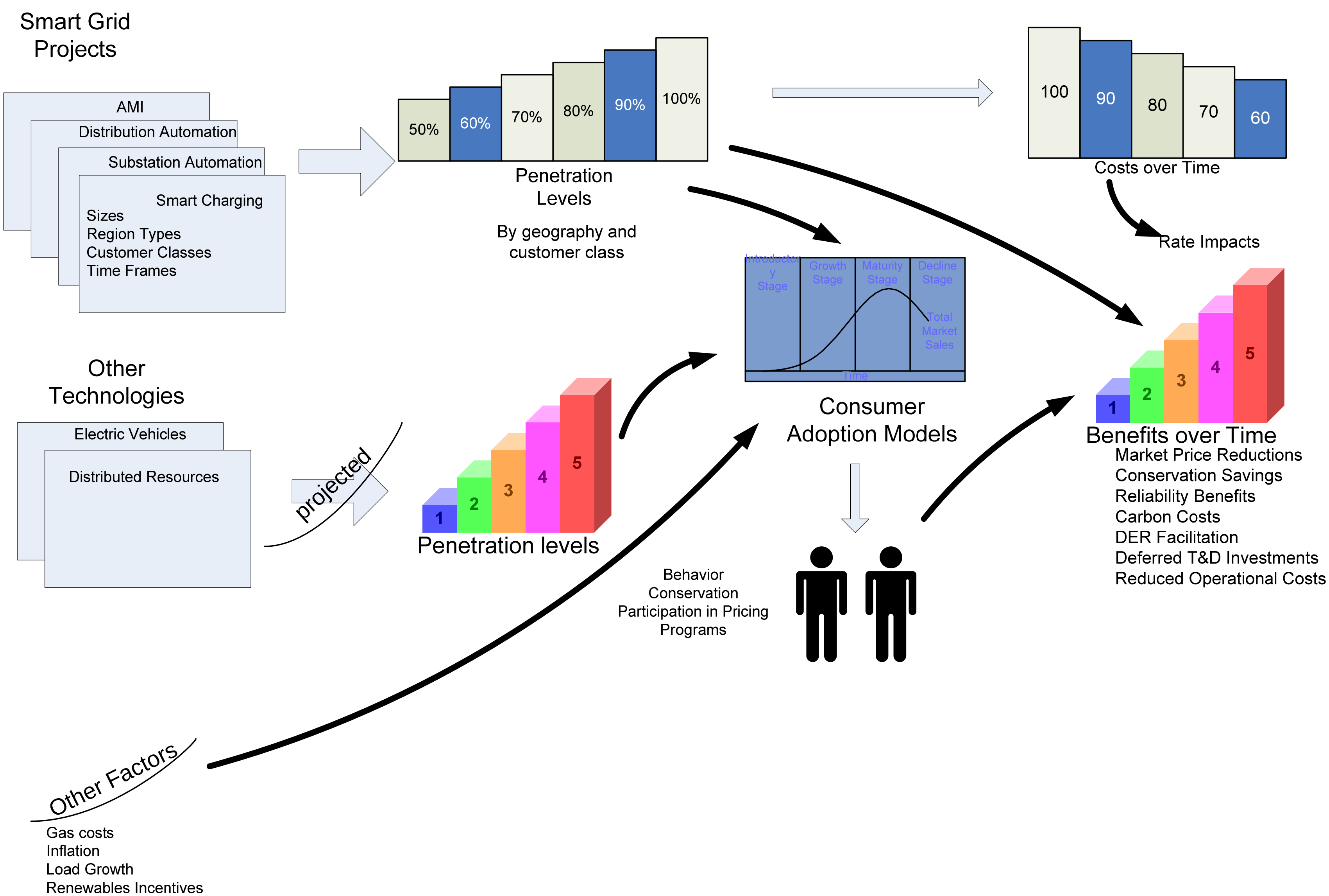


Figure 3 Benefits and Technology Linkages

Relationships Between Benefits and Technologies		DA Rural	DA Urban	SA Rural	SA Urban	Residential Meters	Commercial Meters	Industrial Meters	Residential Gas Meters	Commercial Gas Meters	Industrial Gas Meters	Smart Charging AMI	Meter Communications	Metering Back Office IT	Marketing & Communications	Transmission Automation	Electricity Storage
Reduction in Customer Energy Bills	Market Cost Savings from peak savings																
	Savings from reduced usage																
	Price savings from lower usage																
	Reduced Losses																
	Gas Conservation Savings																
Reliability	***Total Savings from Reduced Outages***																
DER Facilitation	Loading order Changes																
	Increased DER penetration																
	Deferred transmission																
	Smart Charging																
	Carbon reduction																
	Health & Environmental Benefits																
	Deployment Phase Salaries																
	Steady State Salaries																
T&D Rate Benefits	**Total Deferred Distribution CapEx**																
	Total Deferred Distribution OpEx																
	AMI operational savings																
	Transmission loss reduction Benefits																
	Benefits in Contingency Dispatch																
			Well Understood Near Linear with Penetration														
			Well Understood Highly Non Linear with Penetration														
			Not Well Understood														

Smart Grid in Action

Approach

Our approach uses an integrated benefit cost model to reflect the impact of future smart grid activities. The future we envision is based on previous work of the New York Smart Grid consortium where a vision of Smart Grid for New York was developed. We were very comprehensive in our vision and included not only the more typical aspects of Smart Grid such as distribution automation, substation automation, transmission automation, advanced metering infrastructure and some form of Dynamic Pricing.

The other components that relate to Smart Grid that were modeled here include: electric vehicles, gas AMI, increased storage, increased use of distributed and distributed renewables. The overall model structure is shown in the figure shown on the next page. As shown on that figure the model is highly interconnected and very dynamic. A key component of our approach was to try to include as many of the relationships as possible

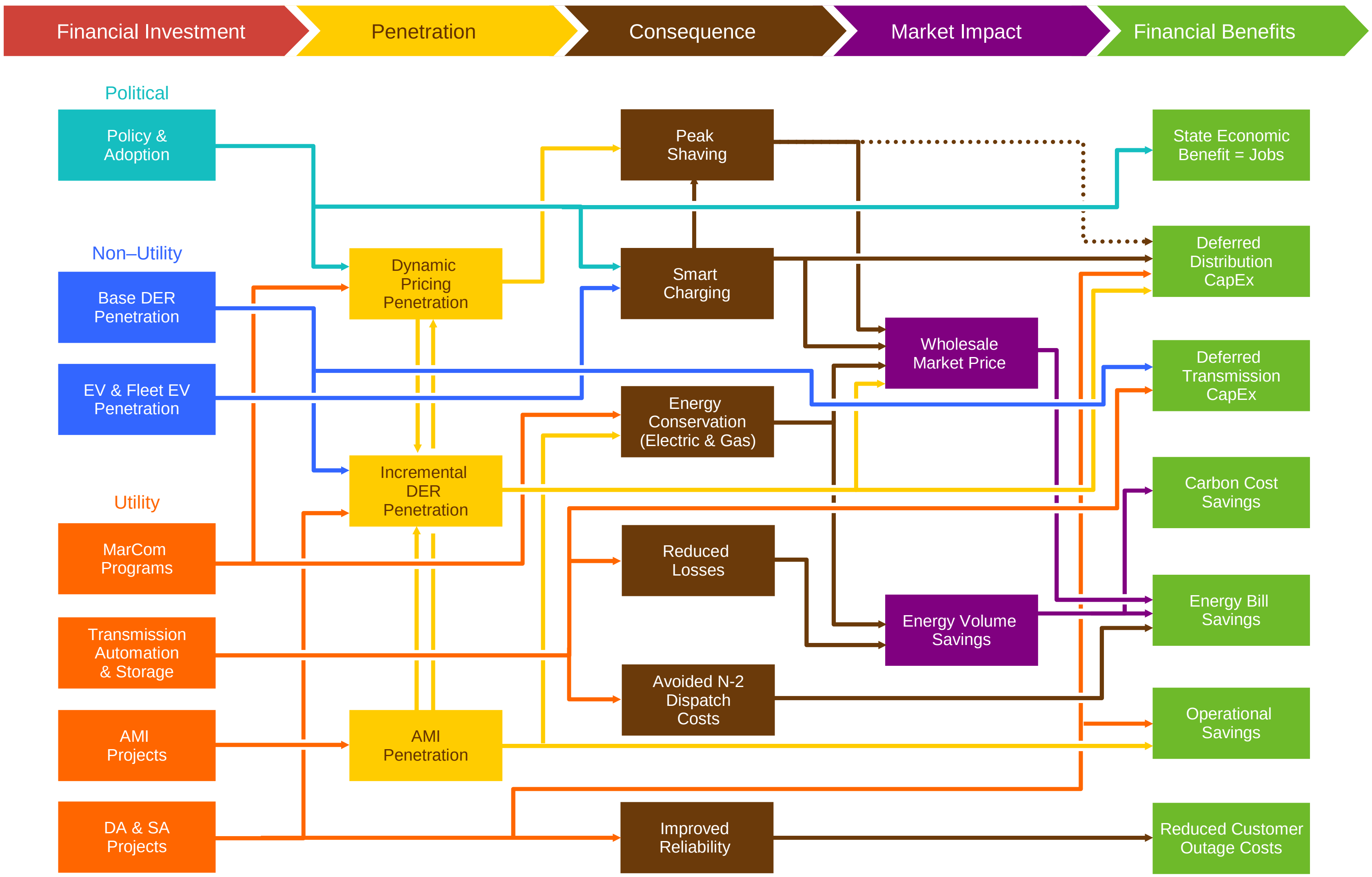
Analysis

The Analysis conducted was an overall benefit cost approach. We calculated the benefits and costs of all of the components shown in Figure 3. We ran different scenarios to determine the relative cost effectiveness of options. Examples of the types of scenarios run included:

- Impact of urban AMI
- Impact of grid storage
- Impact of Smart Charging for Electric Vehicles at different EV adoption rates
- Timing of AMI Deployment
- Different budgets for customer education
- Impact of voluntary vs. uniform application of variable pricing for different customer classes
- Changing the timing of implementation
- Impact of DA / SA on different geographies
- Impact of different asset smart capability upgrade policies on the economics of T&D automation
- Different policies for Dynamic Pricing for different customer classes
- Impact of access to market pricing on Distributed Photovoltaic penetration rates

Figure 4 on the following page shows the way that investment and policy decisions impact state energy goals and ultimately costs and benefits.

Figure 4 Investments, Policies, and Impacts



Roadmap Based On Relationships Between Benefits And Costs

Key Benefits include:

- The Jobs created from Smart Grid projects
- The Impact of Demand Response or other new pricing options namely conservation, price response and the associated energy savings and demand savings
- Congestion reduction and reduction of special NY reliability dispatch provisions; specifically:
- N-2 contingency dispatch
- Gas to oil gas contingency dispatch
- Impact on renewables
- Consumer Benefits of Improved Reliability
- Reduced Line Losses
- Reduced Distribution capital expenditures arising from various peak shaving benefits of AMI, Smart Charging, distributed storage, and DA / SA
- Market price savings derived from peak shaving, distributed resources, distributed storage, conservation, and smart charging
- Energy savings from consumer conservation as a result of better information (gas and electric)
- Reduced utility operations expenses from AMI and Distribution/substation automation

Key Categories of Costs include technology and labor costs of:

- Installation of Distribution Automation systems
- Installation of Substation Automation systems
- Installation of Transmission Automation
- Advance Metering Infrastructure (AMI)
- Enablement of customer Options such as customer displays
- Customer education and marketing
- Smart Charging facilities for Electric Vehicles
- Storage technologies both distributed and grid connected
- Cost of customer incentives to “opt in” to variable pricing in alternate scenarios

Key Roadmap Decision Variables, Parameters and Calculations

Key Roadmap Decision Variables Include:

- How investments are spread by type of project including: AMI, Distribution Automation, Substation Automation, Smart Charging, Transmission Automation, Storage
- How projects are deployed by geography – namely rural, urban and suburban
- How projects are deployed across customer classes between residential, commercial and industrial
- Timing of projects : start and end dates, ramp–up per year
  Model of Consumer market penetration patterns
- Allows Exploration of Priorities, Ordering of Technology Deployments
  Enablement / not of Dynamic Pricing for Different Customer Groups
  Enablement of Smart Charging tariffs/rates
- Incentive levels for voluntary opt in to variable pricing for different customer classes
- Whether or not utilities can realize the price differential gains from energy storage systems

Key Road Map Parameters and Calculations That Can Be Changed in the Model are:

- Relative Price Responsiveness Behavior of Customers by Region / Class
- Adoption of Dynamic Pricing by Customers and Impact of Marketing / Communications
- Extent of Voluntary Customer Conservation due to Information
- Penetration Increases of Distributed Resources due to Smart Grid
- Reliability Impacts of Distribution and Substation Automation
- Congestion Relief from Transmission Automation
- Deferred T&D Capex from Peak Shifting, Smart Charging, DER Penetration
- Smart Charging Load Shape Modification and Impacts on Energy Markets and Distribution Capex

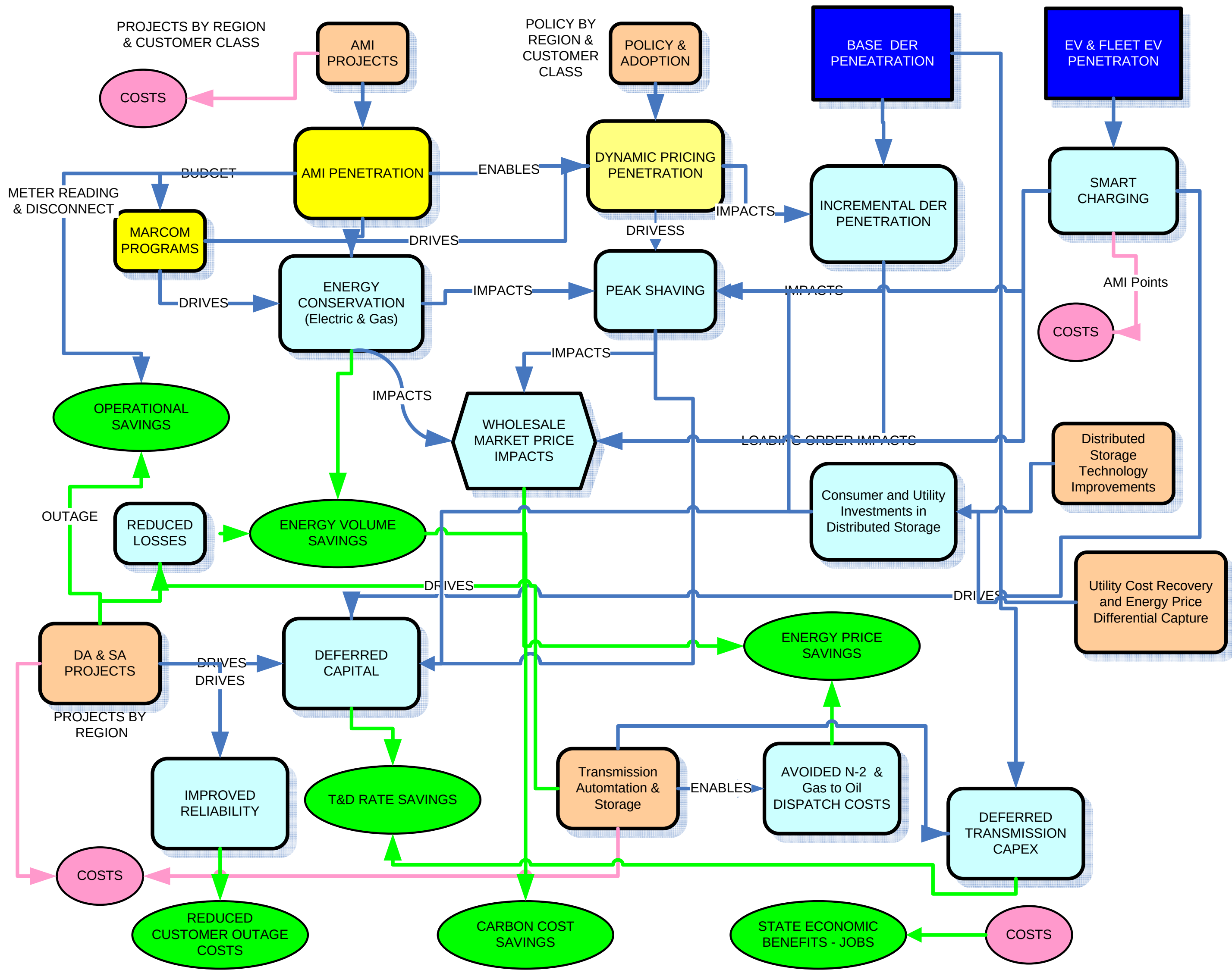
Roadmap Model Structure

Figure 5 on the following page portrays the roadmap model structure and the interactions among all the elements in the model. Figure 5 is a model process view of the roadmap that amplifies the relationships shown in figure 4.

Decisions made in each year of the period 2011 – 2025 affect the penetrations and adoptions of technologies and the ensuing costs and benefits which in turn are the basis for the impacts of downstream decisions each following year.

From this model a stream of costs, benefits, penetrations, adoptions, and outcomes is produced which can be used in an overall assessment of different alternatives.

Figure 5 Roadmap Model Structure



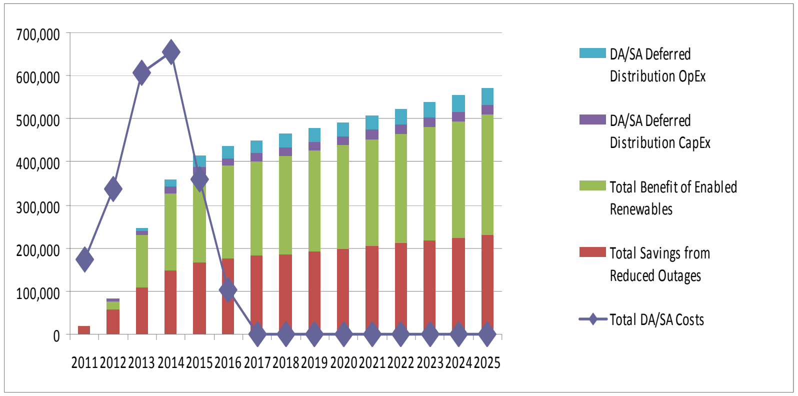
Base Case Scenario Definition

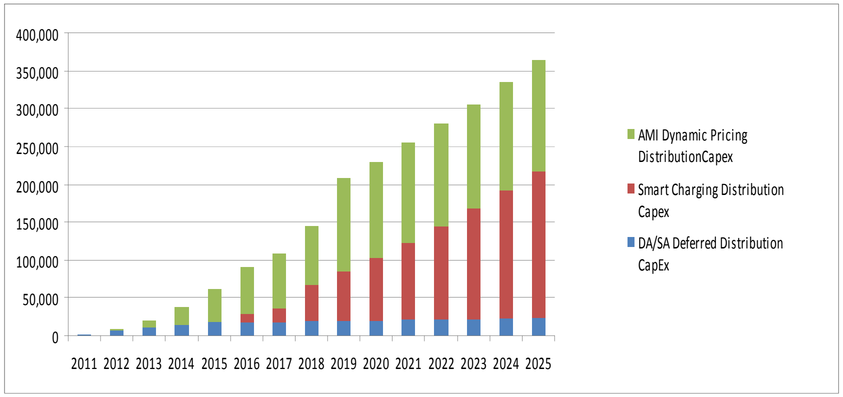
The Key Policy and Investment Decisions that define the base case are described in the table below. These descriptions are qualitative in nature; the details of the various investment projects assumed are shown in the Addendum and later slides

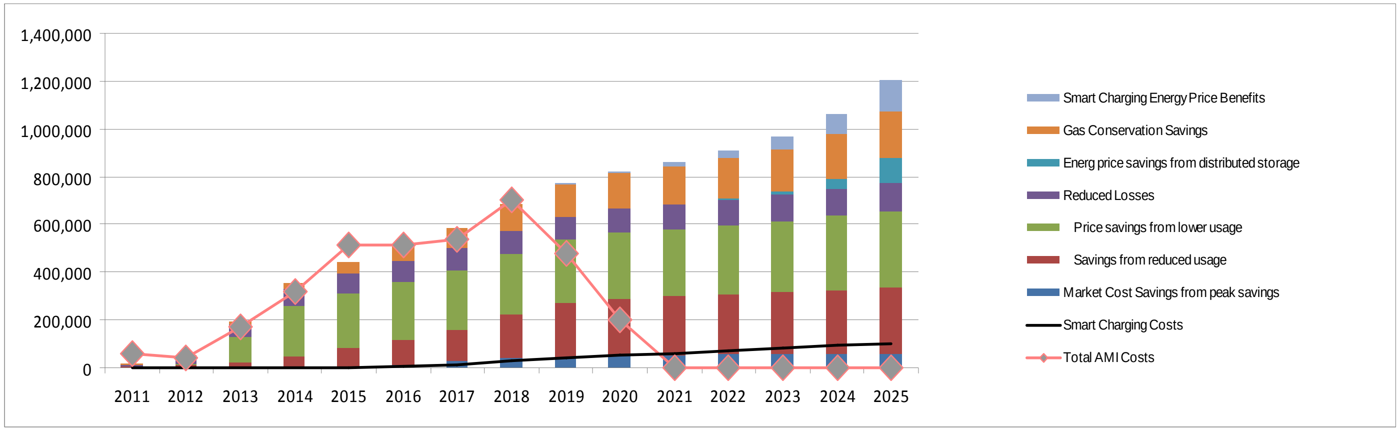
Advanced Metering Infrastructure (AMI)	Any industrial customers not covered by meters capable of hourly TOU rates are covered with AMI in years 1 and 2, except for urban industrial customers that take until years 3-5. Commercial and Residential customers are covered with AMI in years 3-6 for suburban areas and years 5-7 for rural customers. Customers already covered with AMR technologies will see this replaced with AMI during the course of the build-out, note. Remote disconnect is deployed with all AMI installations even though current policy is not to allow the use of it
Distribution Automation/ Substation Automation	Distribution Automation and Substation Automation (DA/SA) is deployed most aggressively in suburban areas (high density and good fit for available technology on overhead and URD feeders and stations) in years 1-6. Urban SA and DA are also deployed aggressively in the same time frame. (This requires some rapid technology development and proof). Rural areas follow these deployments.
Smart charging	Deployed as EV are adopted; reaching 536,400 consumer vehicles and 240,000 fleet vehicles by 2025. Smart and EV adoption are concentrated in suburban and urban areas for obvious reasons. It is assumed that each smart charging spot requires an AMI meter with communications, and that such can be deployed to match vehicle ownership / storage
Grid Level Storage	Attains 630 MW (of 15 minute duration) by 2017
Distributed Energy Resources Penetration (DER)	Incremental DER penetration is driven by a consumer market penetration model used in Photovoltaic projections, based on availability and consumer access to dynamic pricing. Thus the "available" incremental market for PV is driven by AMI deployment and enablement of DP.
Distributed Storage	A similar market penetration model is used to model consumer (negligible adoption) and utility (significant) adoption of distributed storage. Utility financing assumes rate recovery of the storage and realization of energy price differential gains such that the increased capital requirements of storage over distribution expansion are covered. Thus there is no net cost to the utility nor a rate impact to the consumer. However, the storage has a further benefit on market peak pricing due to peak shaving which is a significant state benefit.

Costs and Benefits in the Base Scenario (2011 - 2025)

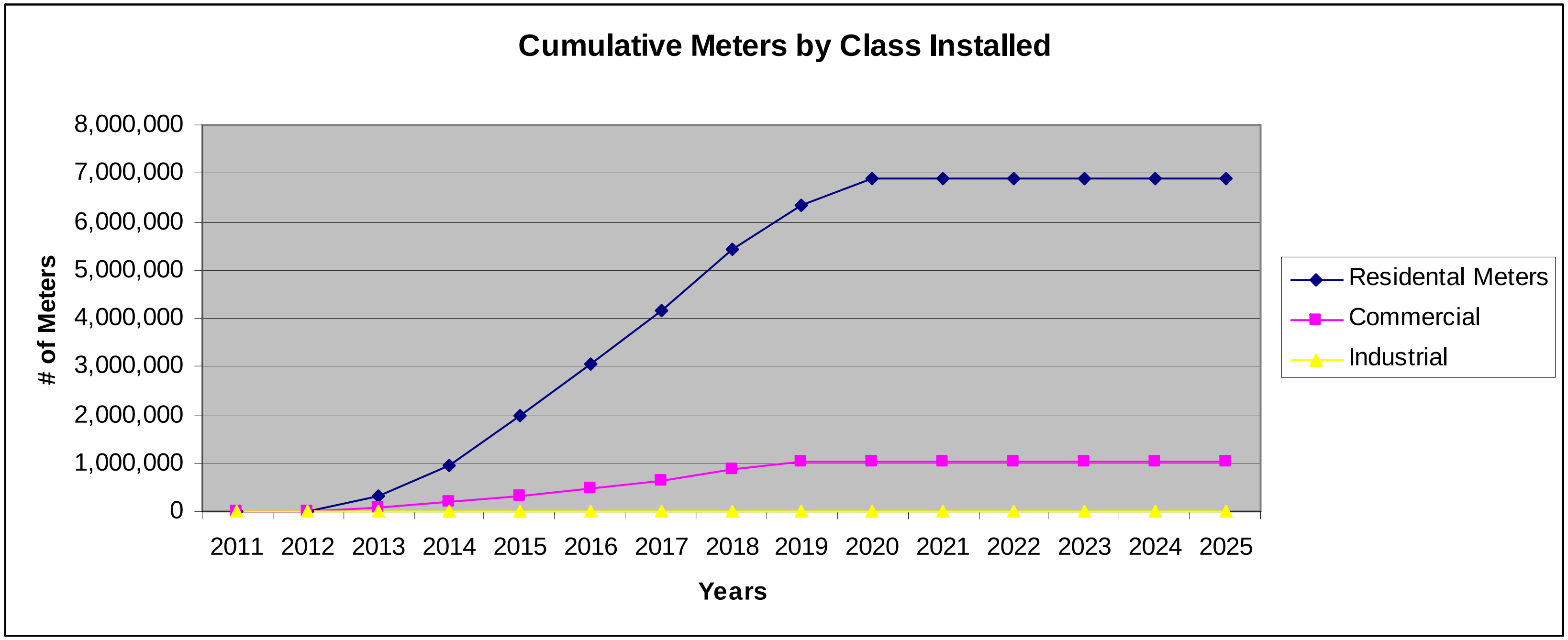
These charts show the build-out of some key costs and benefits over time in the base scenario. Note that the DA costs occur in the early years consistent with a set of aggressive investment programs and that benefits accrue rapidly and build. The T&D rate impacts are much less than the benefits. The AMI costs and overall benefits show a similar if slower pattern. The sources of overall CAPEX deferral are shown in the upper right chart.







Base Case - Rate of Smart Meter Deployment over Time

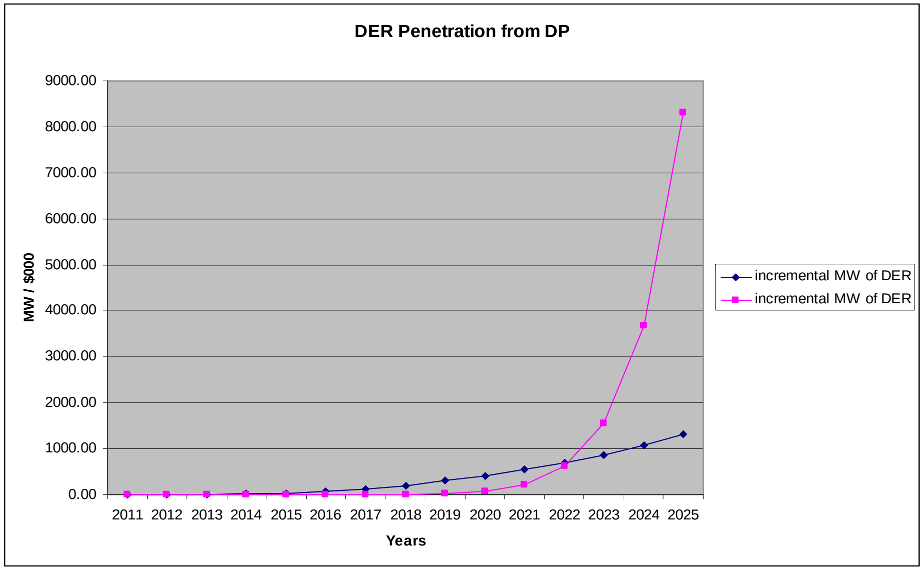


This is the net deployment of AMI meters over time in the base case. As can be seen, the schedule for meter deployment is not particularly aggressive – taking until 2020 to accomplish full deployment. Accelerating this schedule increases net benefits considerably, but at the cost of higher initial rates.

Base Case – Incremental Distributed Resource Penetration

One of the Benefits of AMI and Dynamic Pricing is that Net Metering using Dynamic Hourly Energy Prices becomes available to end consumers. In the Base Case this access to dynamic market prices is only available to C&I customers. DER penetration is analyzed in the following steps:

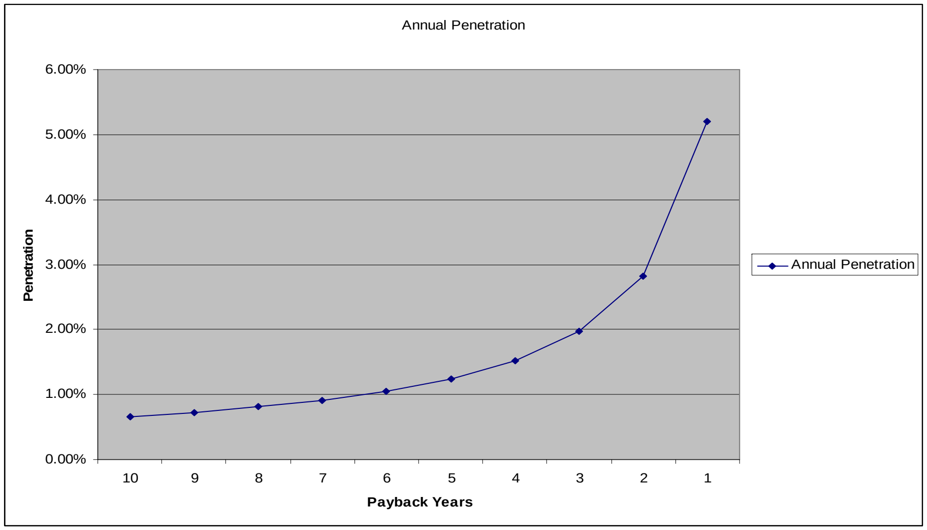
1. Develop a customer adoption model for Photovoltaic systems (as in rooftop or parking lot panel arrays) based on the payback years.
   - Payback years are based on energy prices, cost of installed PV, forward energy price inflation and PV cost improvement, and tax incentives.
   - Adoption is a Weibull function of the payback years typical of observed customer behavior as illustrated in the bottom figure on the right.
   - Access to hourly pricing increases the value of distributed PV as peak production hours align with peak pricing hours; this is estimated on an annualized basis and revised payback years based on access to net metering and hourly prices are calculated.



Base Case – Incremental Distributed Resource Penetration

(cont'd)

- Based on the new payback years a different, larger, penetration is calculated.
- The difference between the base penetration and the revised penetration is the incremental DER penetration due to AMI and dynamic pricing.
- The financial benefit of increased DER penetration is analyzed using the market peak pricing impact similar to that used for basic DP benefit calculation.
- The incremental DER penetration and the market price savings are shown in the top figure on the right. (the energy volume savings accrue to the consumer and are not factored in). This penetration increases greatly in the out years as a result of annual energy price inflation vs. PV technology/cost improvements.



Exploring Alternative Scenarios

Why Scenarios as Changes to the Base Case?

Because the benefits of different Smart Grid technologies and policies interact dynamically over time – based on penetration, customer reaction and technology adoption, and market impacts – it is important to look at how each Smart Grid investment or policy decision impacts the overall picture. Part of this is a “whole is greater than the sum of the parts” effect, part of it is a “saturation” effect or point of diminishing returns; and part of it is simply that some Smart Grid investments have negative business cases in an isolated stand-alone context but become very positive as incremental additions to an overall picture.

The critical issue of aligning benefits with costs over time is another reason to use these scenarios to inform roadmap development. The highest Net Present Value benefit is in general obtained by making all beneficial investments as quickly as possible so that benefits accrue immediately. However, this also means that up front costs are highest and while the total NPV BC assessment or BC ratio may still be the most favorable, the net cash impact to consumers may be unacceptably negative in the early years. Examining scenarios helps understand these effects and look for the “best affordable” roadmap.

Scenarios help us understand:

- interdependencies
- nonlinearities in market impacts and consumer adoption
- incremental vs. stand alone analysis
- holistic effects
- timing of benefits driven by investment timing

Measuring Scenarios

Each alternative scenario explored is created by making a targeted and discrete change in investment strategy to the base scenario. The changes are targeted at:

- types of investments
- policy decisions
- emphasis on geographies or customer types
- changes in the priority (timing) of different investments

Thus, as an example the policy decision “mandate Smart Charging” can be excluded (it is included in the Base Scenario) and the impact of that decision on market price savings, distribution capital (driven by load growth), given the other decisions embedded in the base scenario, can be seen as changes in the different costs and benefits calculated – or in other words, the differences between the base scenario and the “No Smart charging” scenario.

This simple (but critical example) leads to a Benefits and Cost / benefit result different than the base case as shown on the next page. From it we can draw some conclusions about the relative valuation and Benefit to Cost ratio of the Smart charging decision.

Alternative Scenarios Described in the Roadmap

Changes from the Base Case that Increase Penetration / Usage are in Green, Changes that Decrease Penetration / Usage are in Red

		AMI									Dynamic Pricing									Smart Charging									Distribution & Substation Automation						Marcom	Grid Storage
		urban			suburban			rural			urban			suburban			rural			urban			suburban			rural			urban		suburban		rural			
		residential	commercial	industrial	residential	commercial	industrial	residential	commercial	industrial	residential	commercial	industrial	residential	commercial	industrial	residential	commercial	industrial	residential	commercial	industrial	residential	commercial	industrial	residential	commercial	industrial	SA	DA	SA	DA	SA	DA	% of nominal	MW
Base Case: No Res DP; suburban AMI first/urban last; DA / SA early; smart charging, 630 MW grid storage,	**year complete**	11	10	6	10	8	3	9	9	3	N	Y	Y	N	Y	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	100	600
Plus Residential DP Enabled	**year complete**	11	10	6	10	8	3	9	9	3	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	100	600
No DP	**year complete**	11	10	6	10	8	3	9	9	3	N	N	N	N	N	N	N	N	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	100	600
No Smart charging enabled	**year complete**	11	10	6	10	8	3	9	9	3	N	Y	Y	N	Y	Y	N	Y	Y	N	N	N	N	N	N	N	N	N	6	6	6	6	7	7	100	600
No SA / DA	**year complete**	11	10	6	10	8	3	9	9	3	N	Y	Y	N	Y	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y							100	600
No rural AMI	**year complete**	11	10	6	10	8	3				N	Y	Y	N	Y	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	100	600
No suburban AMI	**year complete**	11	10	6				9	9	3	N	Y	Y	N	Y	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	100	600
No Urban AMI	**year complete**				10	8	3	9	9	3	N	Y	Y	N	Y	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	100	600
All AMI and DP immediately	**year complete**	3	2	1	3	2	1	3	2	1	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	100	600
All AMI immediately no DP	**year complete**	3	2	1	3	2	1	3	2	1	N	N	N	N	N	N	N	N	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	100	600
Half Marcom	**amount**	11	10	6	10	8	3	9	9	3	N	Y	Y	N	Y	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	50	600
2X marcom	**amount**	11	10	6	10	8	3	9	9	3	N	Y	Y	N	Y	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	200	600
No Grid Storage	**amount**	11	10	6	10	8	3	9	9	3	N	Y	Y	N	Y	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	100	0
1000MW Grid Storage	**amount**	11	10	6	10	8	3	9	9	3	N	Y	Y	N	Y	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	6	6	6	6	7	7	100	1000

Scenario Descriptions – High Level

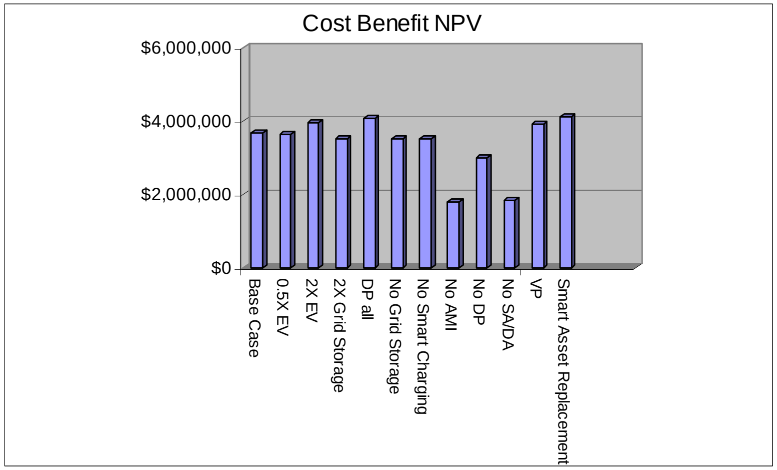
Scenario	*Description*
Base Case	AMI, SA/DA, Smart Charging, Grid Storage, Dynamic Pricing all as described earlier.
Dynamic Pricing for all customers (see section on "Exploring Dynamic Pricing" for amplified discussion.	Residential customer exposed to mandatory DP as AMI is built out; C&I customers hedged as in base case.
No Dynamic Pricing	Consumers in all classes not currently under hourly pricing are NOT exposed to hourly pricing.
No Smart Charging Enabled	Consumers (individual and fleet) do NOT have Smart Charging as EV and AMI penetrate.
No Substation Automation or Distribution Automation	No additional investments in SA/DA smart grid technologies.
Remove AMI from Rural, Suburban and Urban regionns	Impacts of not deploying AMI (and dependent functionalily such as Dynamic Pricing) by region.
Changes to Grid Storage (2 cases)	Remove grid-connected storage; increase maximum storage to 1000 MW.
Change Electric Vehicle penetration (2 cases)	Assume half and double the base case penetrations.
Variable Pricing	Consumers opt-in to time-based pricing based on incentives offered and payback. Various scenarios adjust the timing and levels of participation.
Smart Asset Replacement	Smart Grid automation is installed whenever an asset is maintained or replaced.

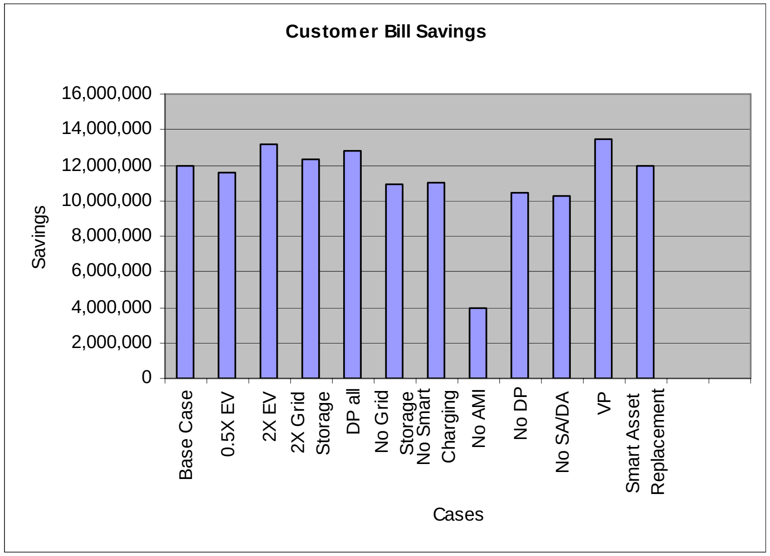
Impact of Scenarios

The relative impact of the scenarios on overall Net Present Value and total Customer Bill Savings are shown in the graphs at right. These figures are only part of the story, of course: each scenario produces these results in different ways – impacts on market prices, energy volumes, distribution capital, renewables penetration, and reliability all vary in complex ways based on the altered investment and policy decisions. "Soft" benefits such as carbon costs and health and environmental effects are also altered.

Some of the scenarios would be impractical for other financial reasons (assuming that any scenario as "black and white" as there are is practical rather than illustrative) . For instance, implementing AMI fully and rapidly produces the greatest benefits because the benefits accrue earlier. However, the short term rate impacts (before benefits accrue) of such a strategy are probably not tenable.

The detailed analysis of each significant scenario follows.





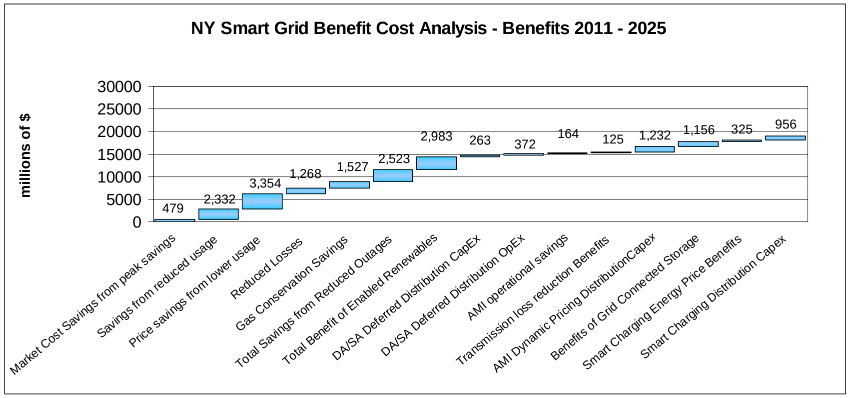
Impacts of Scenarios – Enabling Residential Dynamic Pricing

Extending Dynamic Pricing to Residential Consumers has two significant benefits over the base case. First, the state wide energy bill savings due to peak shaving and market price effects increases from $67M to $465 M. (The bar for $67M "disappears" from the waterfall chart at this scale). Note that in both these cases, it is assumed that a high % of C&I customers are already subject to dynamic pricing BUT have hedged that exposure with "full requirements retail contracts" or the like. Thus the benefits of extending dynamic pricing to all customers is largely derived from extending it to residential customers so long as the hedging behavior is continued.

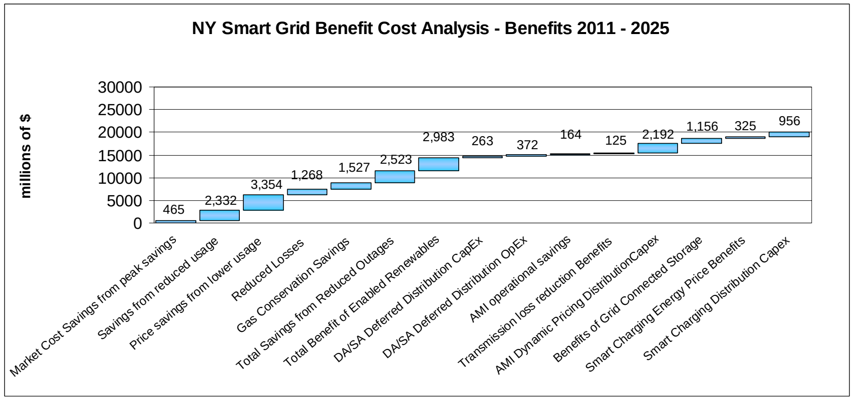
The market price energy savings has two components: peak shaving by residential customers and a market price savings arising from increased Distributed Resources penetration to residential customers. This latter figure is very non-linear based on the MW of DER deployed by all customers, residential and commercial. For instance, in the base case 1300 MW of DER by commercial customers – incremental due to DP – generates $8M of savings in 2025; but adding 1100 MW of residential PV to that total will increase 2025 savings dramatically to $73M. This is a function of the "S" shaped market price impact of peak shaving, and also the expected high correlation of PV adoption with downstate high LBMP prices.

The larger financial benefit by far is the decrease in distribution capital expenditures from $1.232B avoided to $2.192B avoided, thanks to residential peak shaving. This shows up in consumer benefits as a savings in T&D rates.

Equally sizable impacts of Dynamic Pricing would accrue if C&I customers were not able to economically hedge their exposure to real time pricing. This hedging avoids the market price savings but results in peaking generation continuing to provide energy at peak and defeats one objective of the state energy plan. Note, however, that the % of C&I customers who are hedged today is an assumption currently not validated from any available data. While the fraction of C&I customers not on hourly pricing today is relatively small (assumed 25% urban and 50% suburban) they are also assumed to be more sensitive to prices than urban residential customers – thus the overall impacts are similar.



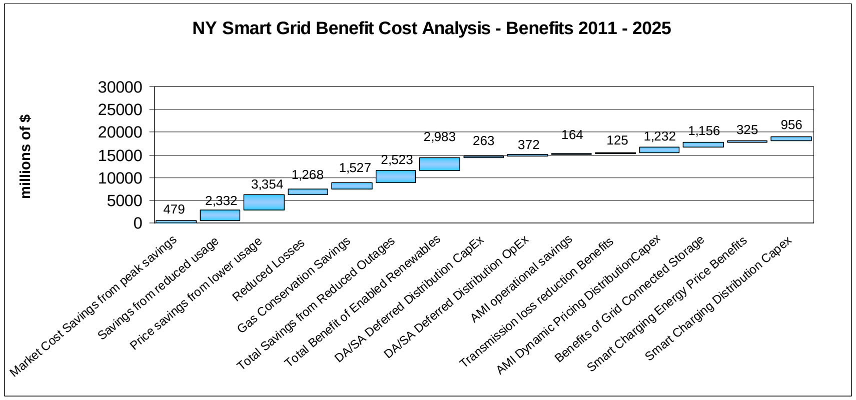
Base Case Benefits vs. Enabling Dynamic Pricing for Residential Customers

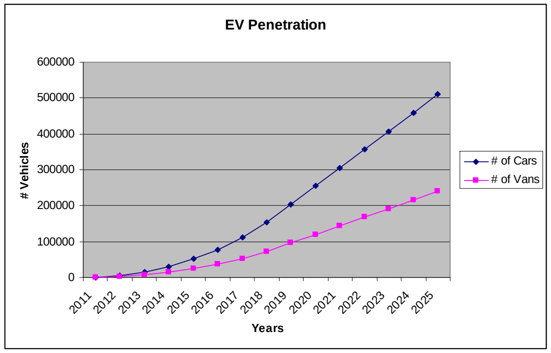


Impact of Smart Charging

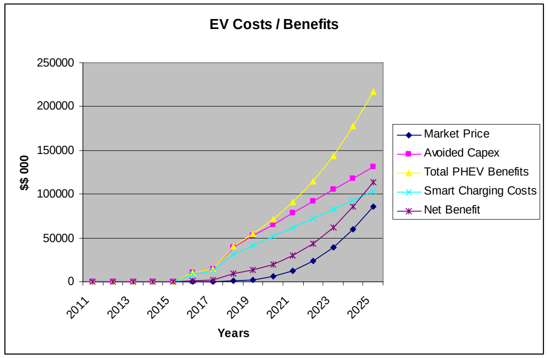
We can see from the high level benefits and costs waterfall that the “No Smart charging” decision saves $325M in energy market price effects and $956M in avoided distribution capital. The energy market price effects are modeled in a fashion similar to the way that market price effects are modeled for dynamic pricing; but using the energy that is time shifted off peak – the smart charging peak shaving effect – that came from the IRC PHEV impact study.

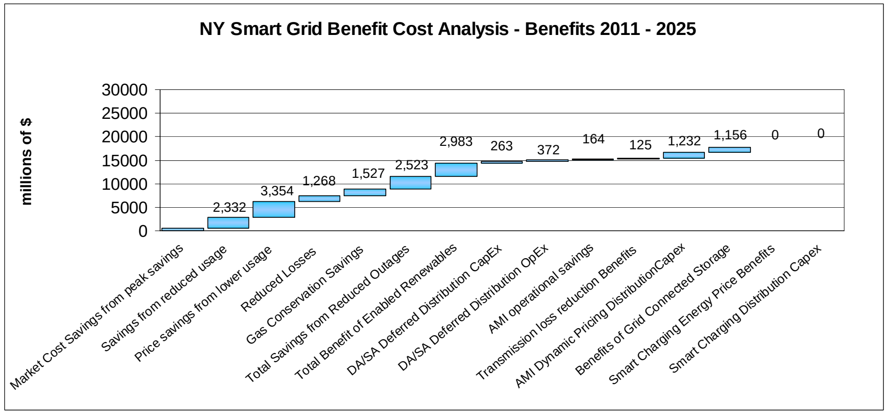
The penetration of EV over time and the build-up of benefits is shown below. Note that in this roadmap study, it was assumed that each smart charging point (i.e. each consumer EV and each fleet location) required an additional AMI point with associated meter and communications costs.



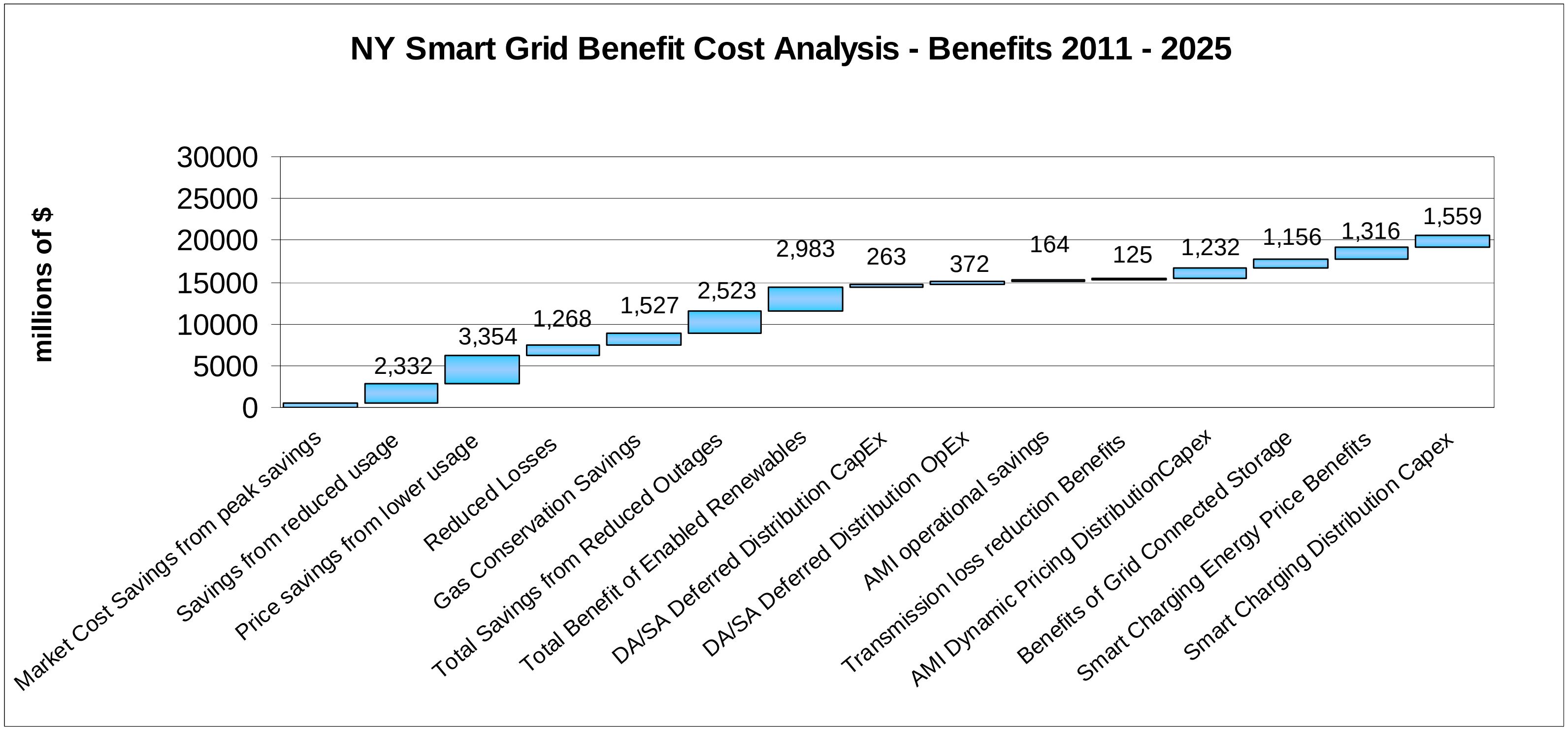


Base Case Benefits (with Smart Charging) and Without Smart Charging





2X EV – Double the EVs



At 12% EV penetration the financials of smart charging increase dramatically. There is a large potential swing in the impact of EV on the market

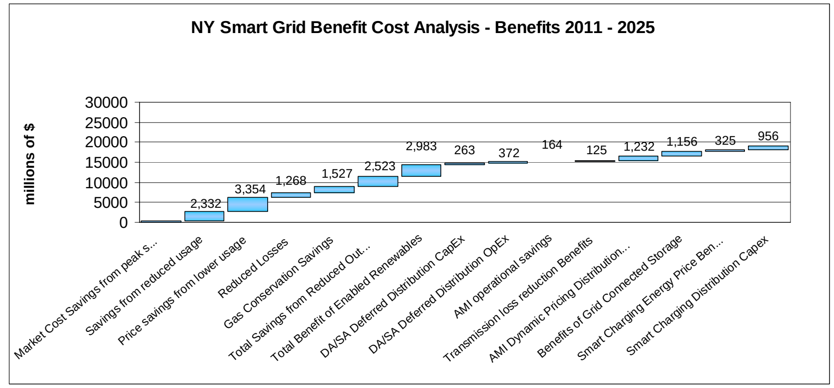
Impact of Distribution and Substation Automation

As can be seen from the waterfall charts to the right, eliminating new investment in Distribution and Substation Automation also eliminates all the benefits that accrue from these technologies. These reduced benefits include:

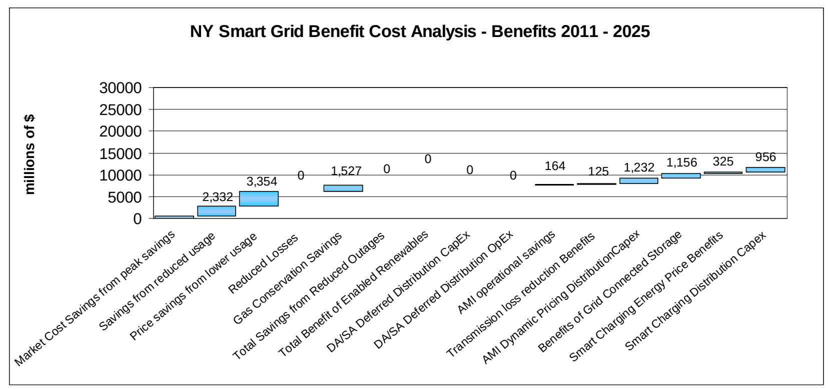
- Reduced Energy Losses (distribution circuits) $1.2B
- Total Savings from Reduced Outages $2.5B
  - Includes consumer reliability benefits and utility operational benefits
- Enabled Renewable Penetration and System Integration $5.3 B
  - Includes cost of integration and the carbon benefits of increased renewables
  - Also includes annual savings from deferred transmission expansion
- Avoided Distribution Capex $250M
- Reduced Distribution Operations Costs $372M

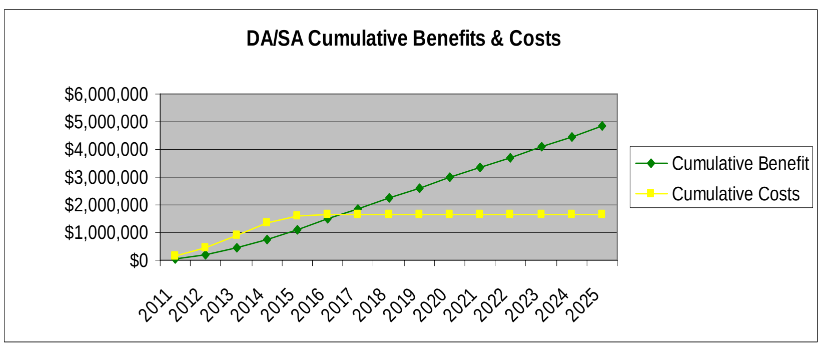
This set of numbers, used in the base case and the scenarios, has a “base” number for the benefits of increased DER penetration of $201M / year. Of this $161M accrues from loading order changes (displaced conventional generation and price savings) and $40M from the annual carrying costs on $400M of deferred transmission capital expenditures. These figures originate in the state energy plan. The total of $2.85 is so large because the benefits accrue early in the process due to aggressive timing of the DA / SA build out.

These figures use 50% of the state energy plan values. In theory, the state energy plan benefits account for peak vs. off peak DER production and are based on the current situation and policies with regard to dynamic pricing, note. Thus these benefits at the higher figure are not unrealistic and are not a double count with the increased penetration of DER attributable to dynamic pricing.

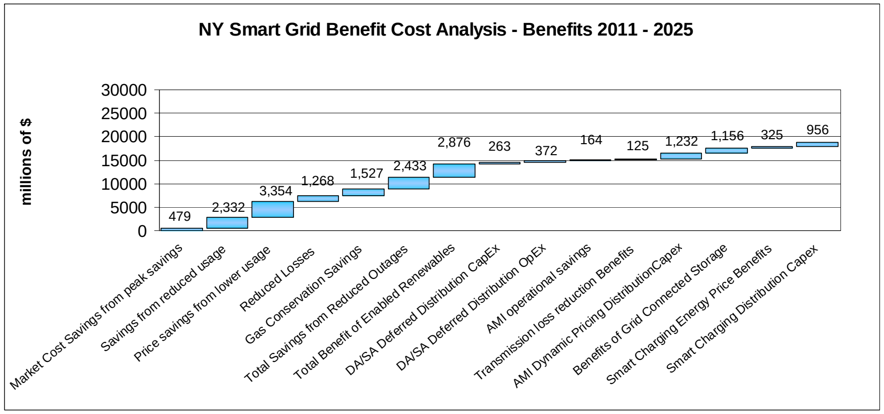


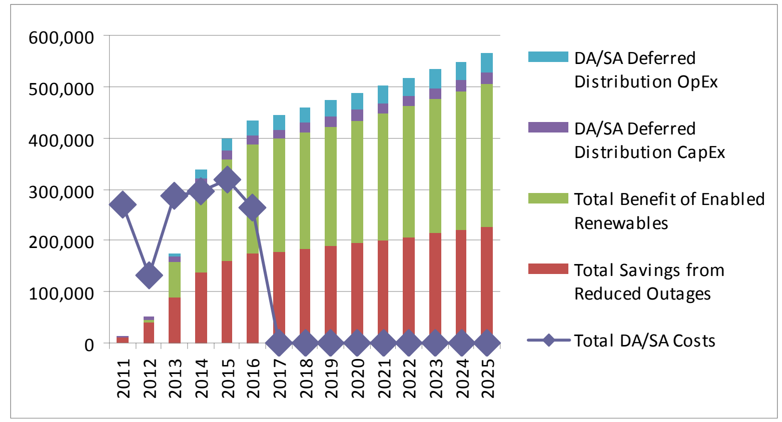
Base Case (with aggressive DA / SA) compared to without additional investment in DA and SA



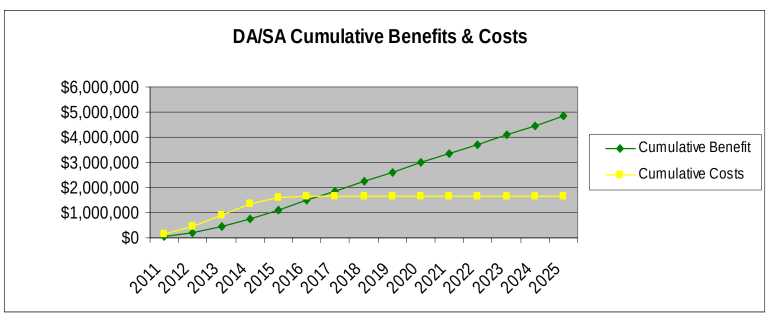


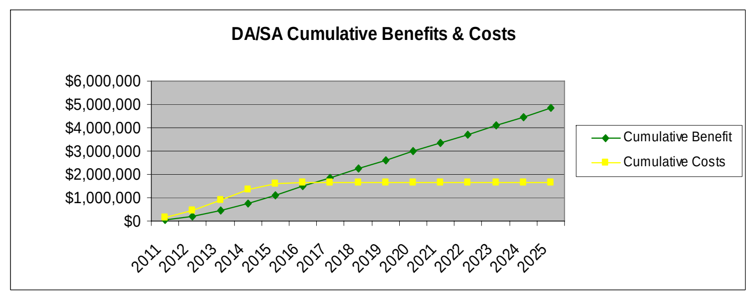
Smart Asset Replacement



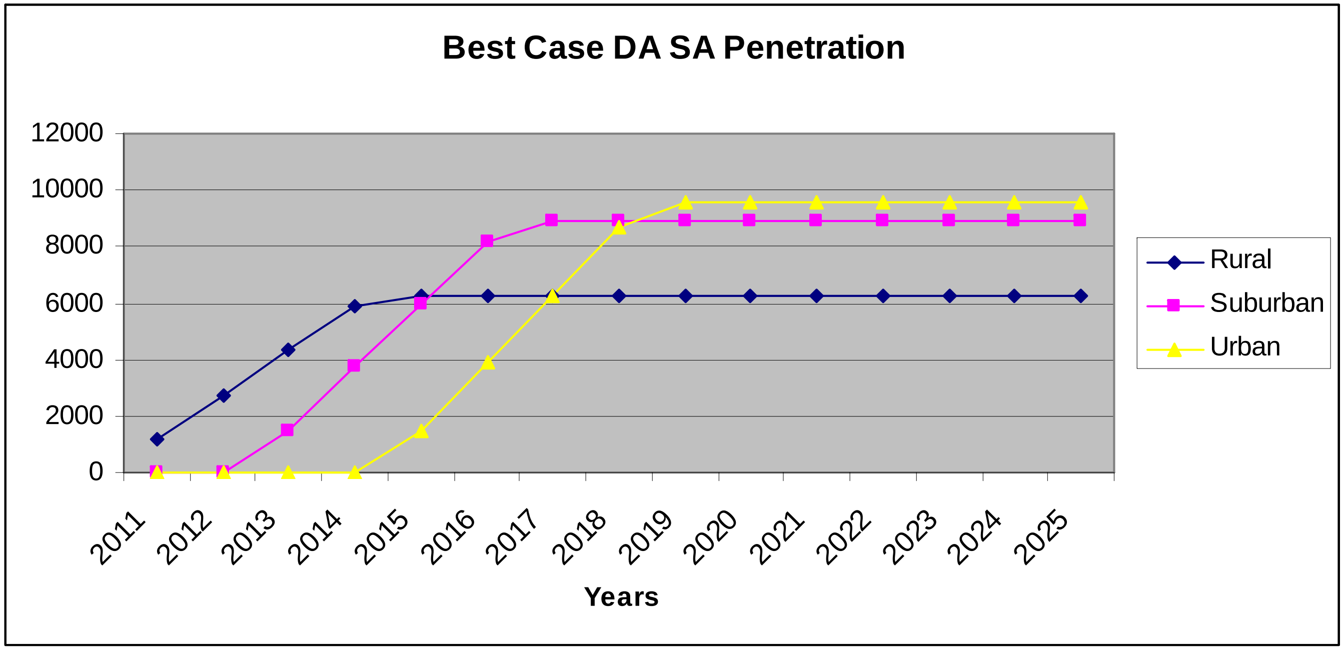


The Smart Asset Replacement approach to DA and SA lowers the costs of DA and SA by assuming that automation is installed whenever an asset is "touched" for maintenance or replacement. This reduces the incremental cost of DA installation considerably. As can be seen in the two lower charts, the costs are about half as much but the benefits end up being the same.





Smart Asset Replacement - DA and SA build up



It should be noted that the initial condition of DA penetration in suburban regions is assumed to be 20%. The incremental build out does not reflect that starting point – this is part of why the rural curve appears to be higher than the suburban curve. The scale is MW of load covered

Exploring Dynamic Pricing

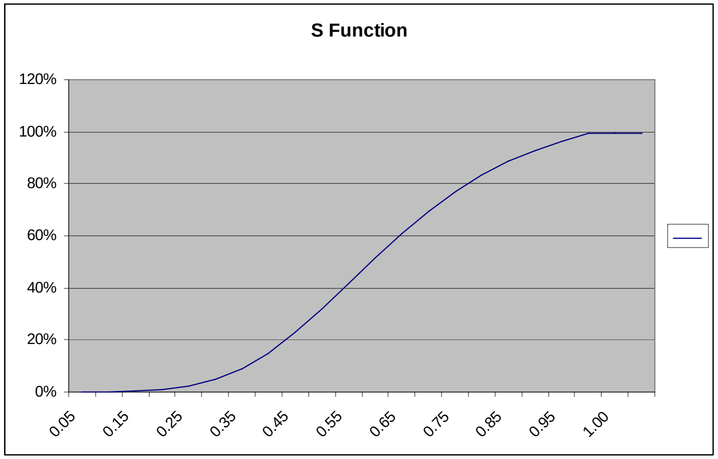
The use of dynamic pricing (varying on an hourly or other real time basis with actual wholesale prices) is a difficult one. Today in NY, it is prohibited to expose residential customers to real time prices. Commercial and Industrial customers are required to have mandatory hourly pricing above certain thresholds in energy usage. It is believed, however, that many if not all C&I customers pay a small premium to reduce this exposure by signing up for energy contracts with competitive retailers. It is impossible to know today what final exposure C&I customers have to real time wholesale price volatility on an overall basis. To be conservative the baseline scenario assumed that a high % of these customers would not be impacted by AMI The NY ISO and the Brattle Group performed a study exploring the impact of consumer price elasticity on market prices and reported that the state wholesale energy bill in total would be reduced by $171,000,000 or about 1.5% were all customers to be exposed to real time pricing.

Modeling Dynamic Pricing Impacts

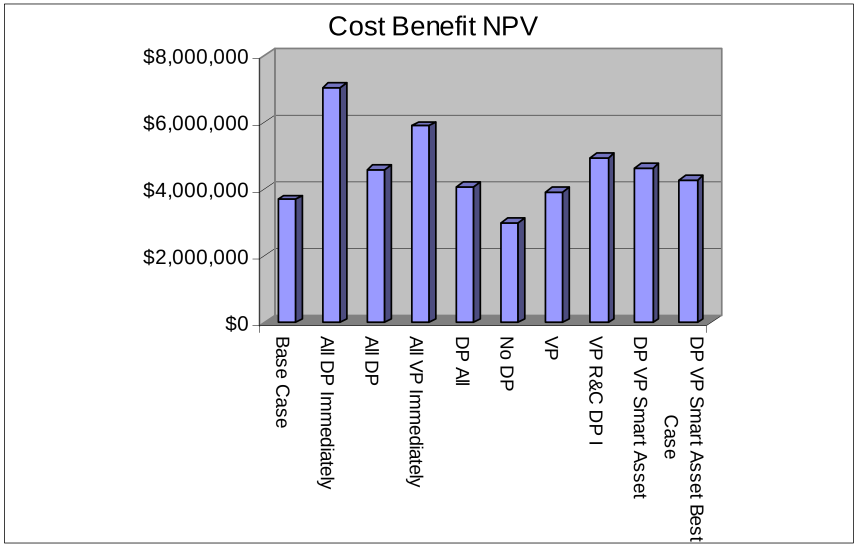
- A high % of C&I customers are assumed to already be exposed to real time prices but to have avoided to varying extent. And in the base scenario, residential customers are precluded from real time pricing. Only “new” C&I customers with new AMI above and beyond the initial conditions set are assumed to be available for real time pricing effects. (Smart Charging is considered apart from this question) In the initial conditions, 75% of urban C&I customers and 50% of other C&I customers have full requirements (assumption)

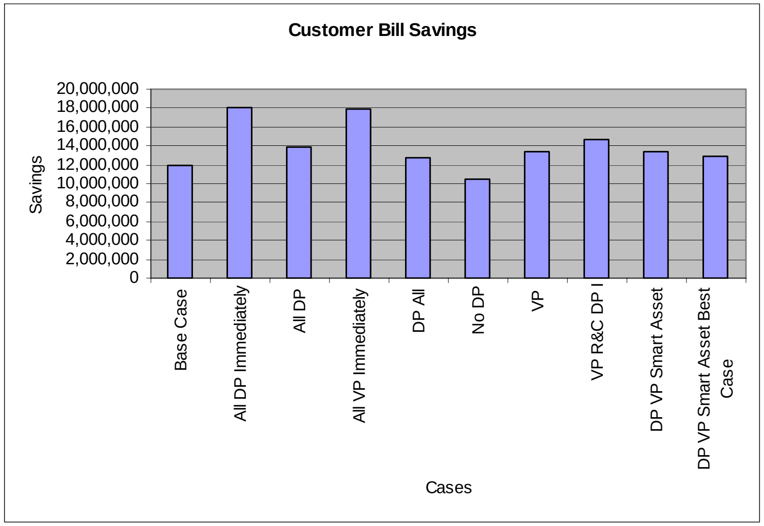
- The beneficial impact of real time pricing is modeled as driven by the MW of load that is newly exposed to real time prices via AMI deployment. Thus AMI has no impact on DP until the build out reaches the threshold of initial C&I real time price exposure.

- The benefit of real time pricing on wholesale energy costs via consumer elasticity is a function of the ratio of new MW load exposed / total MW load. This ratio is passed through an “S” function to derive a multiplier (between 0 and 1) which is multiplied times the NY ISO reported benefit ($171M above) to give a benefit. The S function is such that it “lags” linearity until the new MW approaches 75% of the total, as shown below. The relative elasticities of different customer classes and geographies is estimated and then calibrated such that the S function matches the NY ISO data



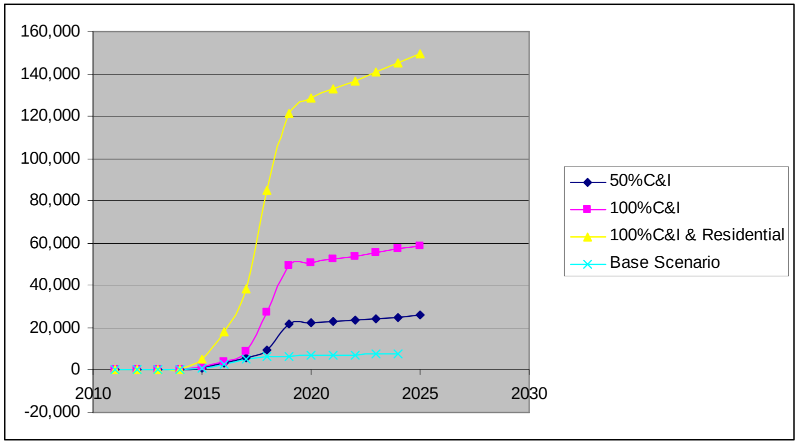
AMI Scenarios

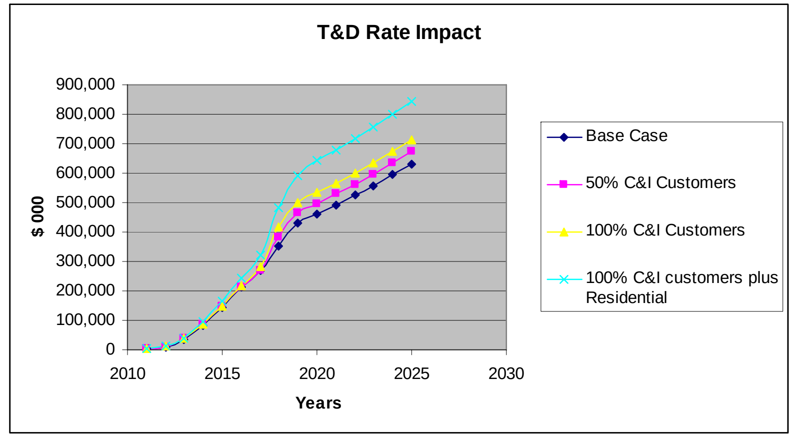


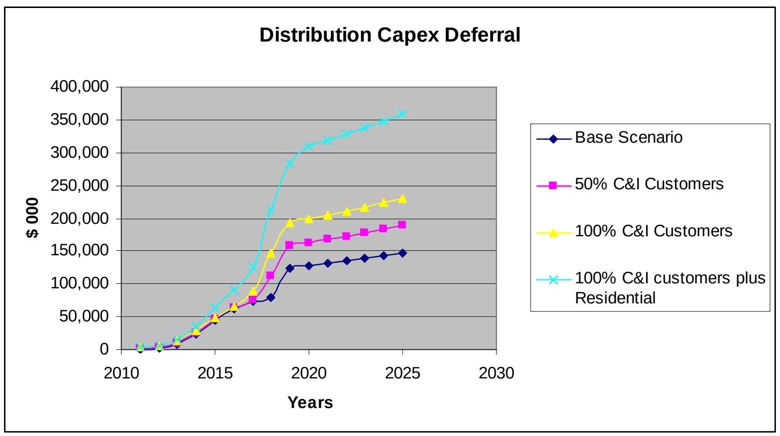


A large number of variations of AMI and consumer dynamic/variable pricing policies were explored. The term "DP" is used to mean mandatory dynamic (hourly) pricing and "VP" means variable pricing with customer opt-in based on anticipated savings net of incentives as described in the details of variable pricing and opt in decisions in subsequent slides. Immediately means that all the necessary AMI meters are deployed aggressively in the first few years (not realistic, of course) and all customers are on DP or VP schemes – these scenarios while not realistic serve to frame the "maximum possible" benefit from AMI and dynamic pricing. Remember that all the other base case smart grid activities are still going on, so the "NO DP" case, for instance, still will show all the benefits of DA, SA, grid storage, and so on. The "All DP" case also assumes that C&I customers who are already on competitive retail contracts are also under mandatory dynamic pricing, whereas in the other cases the assumed % of C&I customers "off the reservation" are assumed not to be exposed to hourly prices.

Impact of AMI and Dynamic Pricing







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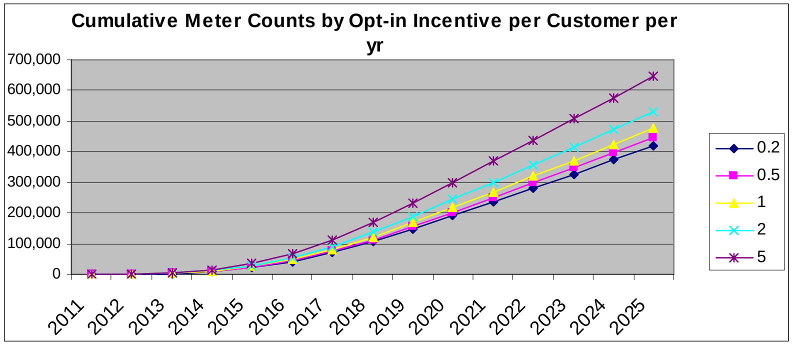
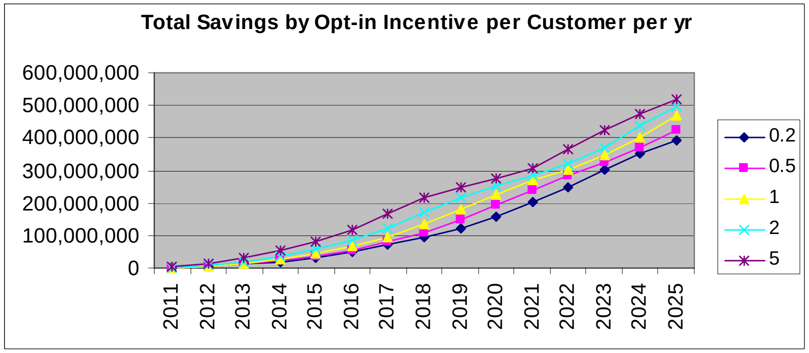
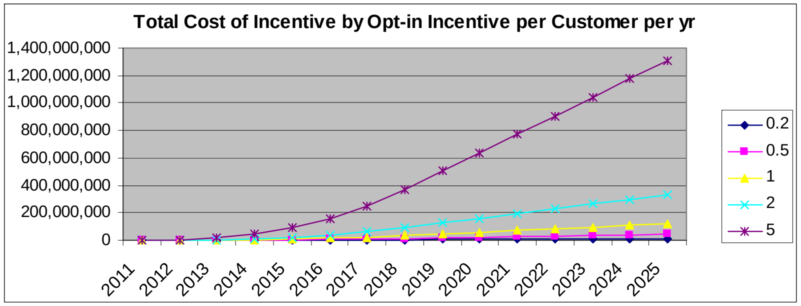
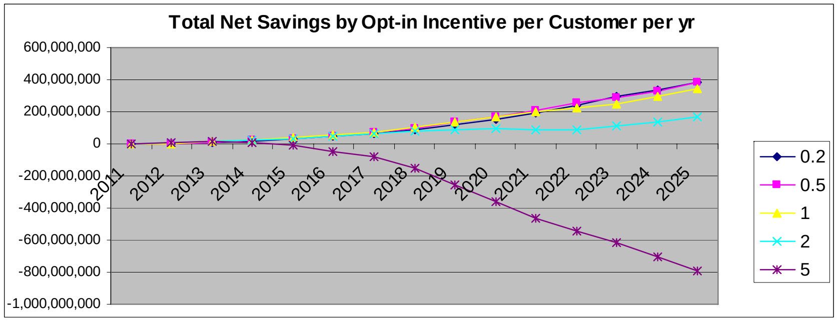
Impact of Different Incentives for Opting into Variable Pricing



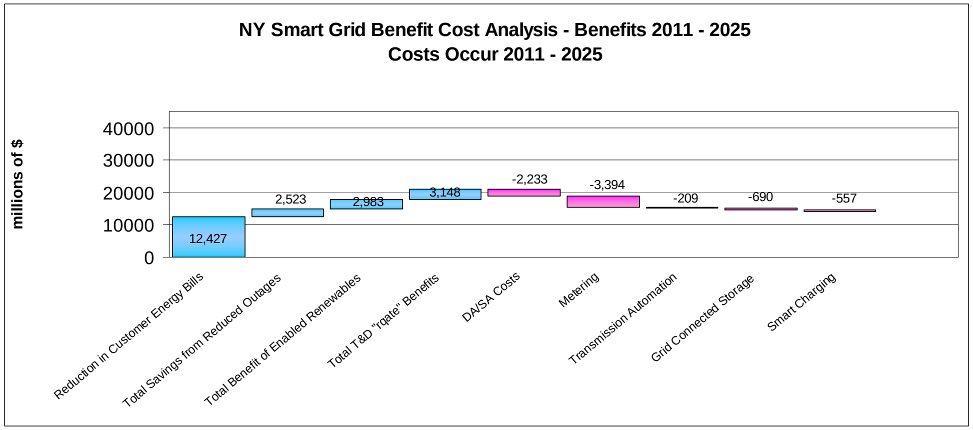


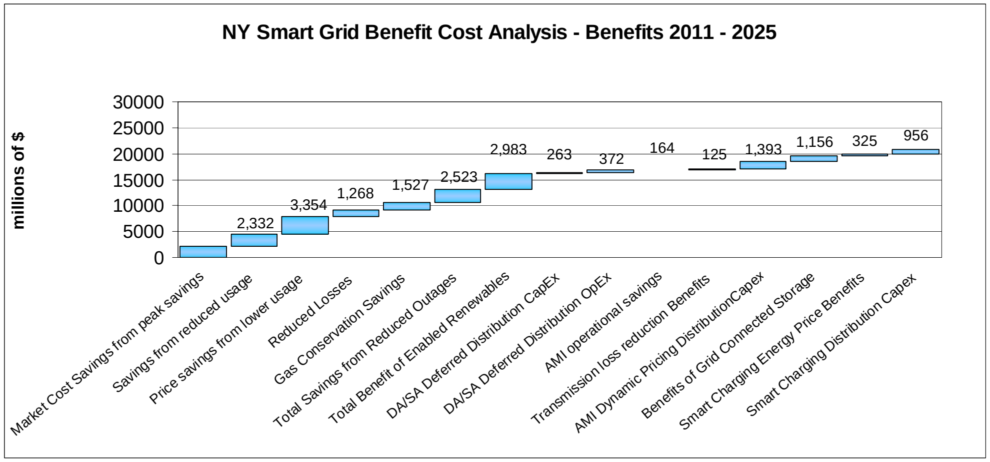




Base Incentives were established at $1 for residential customers, $1000 for commercial, and $5000 for industrial. These were then multiplied by scale factors ranging from 0.2 to 5 and the results of the opt=in program shown. Savings include energy conservation savings, peak shaving market price savings, and market price impacts from conservation. As can be seen, the net savings is very non-linear with respect to the incentive level and a scale factor between 0.5 and 1 seems “best” for this scenario. The opt in model assumes yearly incremental penetration based on the savings that the individual consumer expects – which is a function of energy prices on and off peak, energy peak shifting, conservation, and inflation in energy prices. The incentive is just one factor. (The base incentives were chosen to be a small but not insignificant fraction of monthly energy bills)

Base Variable Pricing





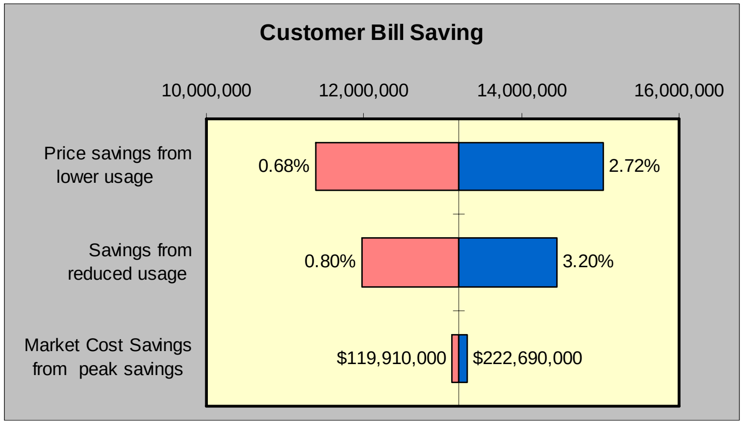
The base variable pricing scenario is somewhat less beneficial than the mandatory DP scenario with all other parameters identical. The variable pricing scenario has the cost of incentives and misses the marginally beneficial customers that add incrementally to market price benefits under mandatory DP.

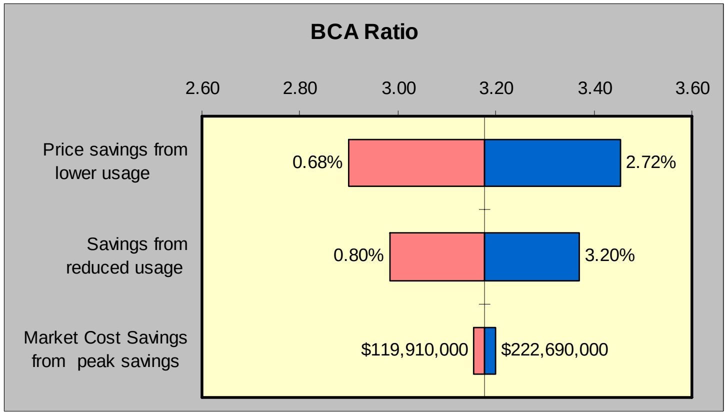
However, the VP scenarios are analyzed in order to demonstrate that the overall cost benefit is still very favorable, and presumably there will be less customer pushback than with any mandatory scheme.

Sensitivity Analysis

The roadmap is far more sensitive to the decisions made around investments and timing, and policy issues, than it is to the particular numerical benefits and underlying data. As an example, the tornado chart to the right shows the sensitivity of total customer bill savings to the basic input information about conservation savings from AMI and the market price savings from peak shaving and from the peak reductions due to conservation. Very large variations in these figures, as shown, result in fairly small variations in the overall consumer benefits.

The point of this is that debating the business case for Smart Grid in New York in the context of the crucial policy decisions around it (such as, whether to have Smart Charging or not) is the discussion that this roadmap attempts to stimulate. Debating the quantified benefits by debating the data underlying the calculations is less valuable – the business case is overwhelmingly positive for Smart Grid given the right policy and investment decisions. The cost and benefits quantitative inputs are not nearly as critical as the decisions that are made.





	Customer Bill Saving			Input		
Variable	*Downside*	*Upside*	*Range*	*Downside*	*Upside*	*Base Case*
Price savings from lower usage	11,390,896	15,034,293	3,643,397	0.68%	2.72%	1.70%
Savings from reduced usage	11,978,553	14,446,635	2,468,082	0.80%	3.20%	2.00%
Market Cost Savings from peak savings	13,118,226	13,306,962	188,737	$ 119,910,000	$ 222,690,000	$ 171,300,000

Key Components Leading to a Roadmap

The following steps were used to develop a Roadmap

1. Define a base case and look at incremental benefits and costs of policy and implementation decisions. This was done carefully, as the sequence of actions is critical and there are many interdependencies.
2. Analyze the existing and potential policy, regulatory, legislative and other issues.
3. Use sensitivity analysis to compare the relative benefit/cost indicators of selected actions.
4. Characterize the potential actions for a roadmap as:
   - Regulatory and Legislative
   - Technological
   - Implementation
   - Regional Economic

Key Observations

- Smart Grid investment is highly cost beneficial for society
- DA and SA are most beneficial – should be a priority in much of state. These are probably best handled via normal utility investment decisions outside any special Smart Grid processes.
- Grid storage and use of demand response for avoiding N-2 contingency dispatch is highly beneficial, but storage as a way to alleviate the gas-oil contingency dispatch seems uneconomic today
- Suburban areas are highest priority for AMI for energy price impact and conservation
- Urban areas are the lowest priority for AMI
  - The use of remote disconnect to facilitate load reduction for network relief as a “risk reduction” tool is significant but was not assessed economically
- The access of consumers to dynamic pricing is a powerful incentive for added DER penetration
- The economic benefits of Smart Charging are substantial and the costs of not having a state policy that strongly encourages or mandates smart charging are large
- Jobs are created in both the deployment and full scale stage of Smart Grid contributing significant regional economic benefits
- Carbon savings are not insignificant
- Absent conservation, demand response, and dynamic pricing, AMI economics are still favorable but much reduced.

Key Observations *(cont'd)*

- Smart charging has significant benefits but cost of additional AMI point / vehicle is high. Policies to encourage lower cost technical solutions using on-board vehicle electronics, for instance, should be encouraged. Smart Charging overall should be a state policy so that charging spot suppliers and vehicle OEMs can incorporate the appropriate capabilities into their product plans.

- Potential conservation savings from AMI information to consumers is high but needs education and outreach to harvest value.

- Potential market price impacts of consumer dynamic pricing response is very high. Almost all of this benefit can be captured via a well designed voluntary opt-in program at the cost of incentives

- AMI and Dynamic Pricing (DP) can have significant impacts on DER penetration which benefits Transmission, Distribution, Energy Prices, and RPS attainment

- Current state policies preclude DP for residential consumers and it is believed that many commercial customers avoid DP (TOU rates) today by hedged contracts with retailer providers – this has the effect of reducing or eliminating state wide market price savings from DP

- Dynamic Pricing, Smart Charging, and DER penetration all have market price impacts. At high levels these appear to have additional synergies (not included in these numbers)

- Distributed storage has significant potential benefits in terms of deferred distribution capital and reduced energy peak pricing. The correct policies for utility capture of the energy price differential are key to realizing this.

Key Strategic Steps Required to Achieve the Vision and Objectives of the Roadmap:

These steps will each be described in more detail in the following slides:

- Support key regulatory and legislative actions.
- Ensure the Smart Grid provides customer enablement.
- Modernize the Grid.
- Ensure diverse supply integration.
- Provide economic benefits.
- Advance technological development.
- Support the customer research needed to ensure the smart grid benefits

1. Support Key Regulatory / Legislative Actions

- Re-Define scope of Smart Grid business case analysis to include full spectrum of Smart Grid technologies and benefits as part of filings for Smart Grid approval.
- Test key program design options with pilots
- Explore voluntary dynamic pricing for all customer classes
- Explore whether mandatory dynamic pricing of some form is appropriate for some classes and revisit the state-wide impact of competitive retail “full requirement” supply contracts that bypass TOU pricing
- Develop programs including outreach for smart charging and alternatives to additional AMI points
- Explore the regulatory and technical issues of using the public internet to provide AMI communications
- Develop pilots to test effectiveness of customer response and education
- Cost recovery for utilities for cost effective AMI installations.

2. Ensure the Smart Grid Provides Customer Enablement

Enabling the customer represents an important aspect of developing the New York State smart grid. Providing the customer with adequate and timely information and options will encourage them to make informed decisions. The options will come in the form of pricing that more closely reflects the cost to deliver energy (Demand Response, time of day, variable), simple, interoperable equipment (AMI, smart devices, DG, storage, PHEV) and network automation to manage their energy costs. These decisions will benefit customers and be aligned with state energy policy goals. In essence, the customer becomes an active participant within the grid instead of being a passive user of electric services. Key benefits from customer enablement are the bill reductions from conservation impacts and the shifting of load.

- All commercial and industrial customers should have AMI.
- All commercial and industrial customers should have access to time differentiated prices.
- Utilities and other providers will provide commercial and industrial customers with options to take advantage of time differentiated prices.
- Where it is cost effective residential customers should have AMI.
- Residential customers should have access to time differentiated prices.
- Utilities and other providers will provide residential customers with options to take advantage of time differentiated prices.

3. Modernize the Grid

The grid connects the customer to generation, transmission and distribution in the electric power system. As the aging infrastructure is upgraded, it will provide significant opportunities to improve cost and reliability through advanced sensors and controls (e.g., PMU) designed to limit outages (self-healing, islanding), linked by integrated communications networks and managed by intelligent advanced systems and operations. As grid enhancements provide a reliable supply of electricity at reasonable costs, they elevate security risks (cyber and physical) and the importance of managing them. Standards that are being developed by National Institute of Standards and Technology (NIST) with support from the GridWise Architecture Council will enable the safe and efficient operation of the smart grid. The key benefits of upgrading the grid are increased reliability and reduced losses. DA and SA are highly cost effective.

The following are actions that will be needed to ensure the smart grid in New York will modernize the grid:

- Implement DA and SA throughout the power system in NY
- Provide cost recovery for these investments

4. Ensure Diverse Supply Integration

The energy supply portfolio will continue to evolve and several newer types of generation (wind, solar) tend to be intermittent and less predictable. Incorporation of renewable energy sources into the electric power grid will require a combination of solutions including storage, demand response, transient mitigation and advanced analytics. This integration will facilitate a more timely achievement of renewable portfolio standards.

The following are actions that will be needed to ensure the smart grid in New York provides for diverse supply integration:

- Continue to support the development of large scale and customer side renewables
- Explore utility ownership and or utility programs to promote customer side renewables
- Pilot storage technologies in combination with demand response and renewable technologies
- Address recovery mechanisms and incentives for utilities to invest in distributed storage; in particular how utilities can realize the time value gains from energy stored in distributed facilities.

5. Provide Economic Benefits

New York will be a national leader in the implementation of Smart Grid and Smart Grid industries will cluster in New York providing significant economic benefits. This will attract additional industry. The universities of NY will become national leaders in the field of Smart Grid.

The following are actions that will be needed to ensure the smart grid in New York provides customer benefits:

- Continue to support the collaboration between universities, industrials, and utilities at the New York Smart Grid Consortium.
- Add curriculum as needed at NY universities to train the Smart Grid workforce.
- Develop the research Nexus

6. Advance Technological Development

Work within the NY Smart Grid Consortium Nexus, the Smart Grid Innovation Center, and other state R&D organizations to reduce the costs of all technology related to grid automation and customer enablement.

- Design and test interfaces building on the experience of state entities with smart grid interface testing. (example, National Grid STC 2009 testing program)
- Build demonstration homes and businesses with these technologies
- Establish open source smart grid testing program
- Participate in available DOE ARPA-e and other R&D initiatives as appropriate
- Develop mechanisms to cross fertilize state R&D activities and commercialize promising technologies

7. Customer Research

The analysis conducted in this study clearly illustrates the large potential benefits of time based pricing and other related customer activities. The research on this topic is not conclusive. Specific areas to explore include:

- Role of enabling technologies such as displays or Behavioral Programs
- Test new rate options
- Explore role of distributed generation on dynamic pricing
- Research on the future potential roles of retailers and other non regulated firms in developing services related to AMI.
- Research on the actual pricing options large C/I customer receive from retailers and what that actually means as it relates to the impact of AMI for these customers.

ADDENDUM

Anticipated Benefits – Overview Matrix - Thought Starter

Anticipated Benefits	Direct Customers (rate payers)			In Direct Users	Electric Sector			Academia
	Residential	Commercial	Institutional	NY Residents	Utilities	Utility Shareholder	Other	Academia
Improved Cost Management and Customer Satisfaction								
Lower Customer Electric Bills	●	●	●	○	◐	◐	○	◐
Increased Customer Satisfaction	●	●	●	◐	◐	◐	◐	◐
Lower Market-Based Cost due to Price Response	●	●	●	◐	◐	◐	○	○
Reduced Congestion Costs	◐	◐	◐	○	●	◐	◐	◐
Access to New Products and Services	●	●	●	◐	●	○	○	○
Enhanced Power Quality & Reliability								
Smart Grid devices on the T&D system	◐	◐	◐	○	●	◐	◐	◐
Asset Infrastructure Optimization	◐	◐	◐	○	●	◐	◐	◐
Positive Societal/Environmental Impact								
Job Creation	◐	◐	◐	●	●	◐	◐	●
Enabling More Renewables And Storage	◐	◐	◐	○	●	◐	◐	○
Adoption of Electric Vehicles	◐	◐	◐	○	●	◐	◐	○
Enhanced Quality of Life	●	●	●	●	◐	◐	◐	◐

● Primary/Direct Beneficiary ◐ Secondary/Indirect Beneficiary ○ Not Applicable

Details of Costs and Benefits Summarized

- The Following Pages Describe and Discuss the Detailed Basis of Cost and Benefit Assumptions and Calculations
- Section numbers are the sections in the full written report
- Sources of data are noted in the written report

Key Scenario Parameters

Variable	Value
Conservation savings - Electric	2.00%
Conservation savings - Gas	1.00%
Cost of Carbon - $ / metric ton	$20.00
Reduced Distribution Losses	1.00%

Key Economic Parameters

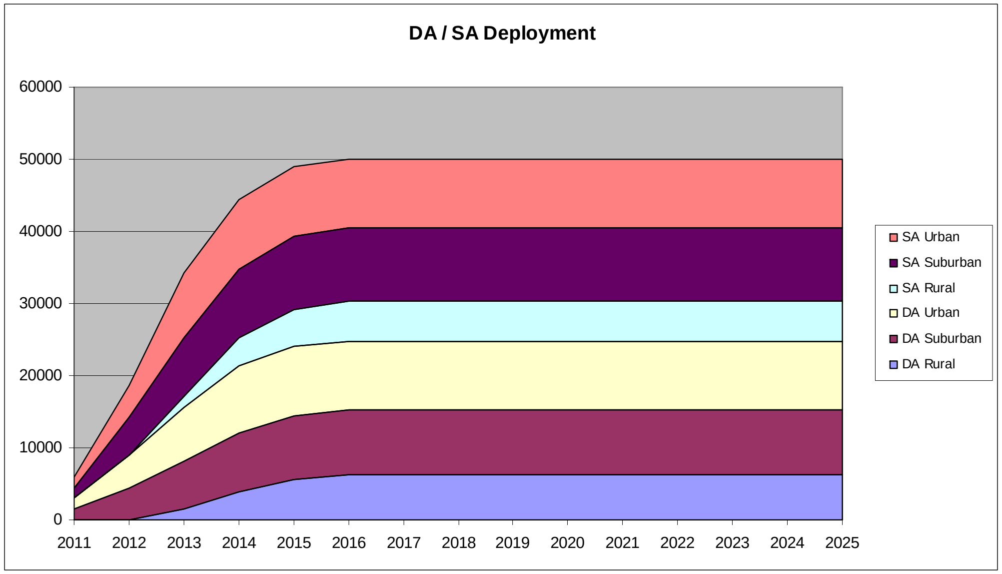
Inflation Rate	2% - 3%
Discount Rate for NPV	7%
Rate Recovery	12%

Rate recovery is expressed as % of CAPEX / yr – i.e. net of asset life, depreciation, and ROI allowed. In reality this would reflect differences in asset life for different Smart Grid assets and differences in rate structures across public and investor – owned utilities

Costs are escalated annually and salaries until 2025 as noted on those pages.

Distribution and Substation Automation Costs

DA/SA	Unit Cost		
DA rural	$	60,000	/ MW
DA urban	$	40,000	/ MW
SA rural	$	62,500	/ MW
SA urban	$	10,000	/ MW
DA+SA rural	$	122,500	/ MW
DA+SA urban	$	50,000	/ MW



- Per unit MW costs are estimated on this basis: (no change from first draft) costs are inclusive of communications / installation (using communications costs per point that are significantly higher than AMI per meter communications costs.) Sources – various KEMA studies
- Peak design includes allowance for cold load pickup and rollover
- Back office IT costs are $10M – 20M per utility
- The costs are assuming 100% deployment statewide. Many feeders downstate already have some level of DA deployed - costs reflect this per the assumed “initial conditions” for DA and SA.

Transmission Automation

Transmission Automation Cost Calculation	$1,000,000 per station x	150 stations =	$150,000,000
IT Costs			$50,000,000
Total TA Cost			$200,000,000

TA costs are substation automation costs based on various KEMA projects. # of stations is an estimate based on covering 100 total 345 and 230 kV stations and 50 110-138 kV stations where congestion is an issue. A "retrofit cost" for SA to a 230 kV station was estimated in 2006 at $980K (greenfield is half that). These costs will vary with the extent of existing digital protection and some stations in NY will already have substation computers. Back office costs of $8M / utility are also estimated.

In the Roadmap these costs are assumed to be incurred in years 1-5 as they are part of the overall benefits claimed in transmission capital savings due to DER penetration, savings from loss reduction, and are also assumed to be essential to the harvesting of transmission congestion reduction.

Transmission Automation – Grid Connected Storage

Grid Connected Storage Assumptions

Period for "carrying cost"	7	years
Duration needed for Grid impact	0.25	hours
MW redisptached for N-2	1000	MW
MW fuel switch applicable to	6000	MW

Benefit of going from N-2 to N-1	**$**	**30,000,000**
Benefit of avoiding gas-to-oil fuel contingency	**$**	**30,000,000**

Storage Technologies and Costs

Storage Technologies	Cost / KWh 2010	Improvement % / yr	Applicability	Efficiency	Operating cost / kwh	Tax incentive
Large scale hi-temp/hazmat batteries	700	10	Industrial rural and suburban customers; Substations	75	0	0.3
Li-Ion, zinc air	1200	15	Suburban feeders and consumers; urban buildings	95	0	0.3
ICE energy	350	10	Urban commercial and residential buildings; Suburban commercial buildings	70	0	0
CAES, liquified air	700	5		70	0.05	0
pumped hydro	2500	0	Grid connected diurnal shifting; ancillaries	65	0	0

Grid Connected Storage is assumed to be used in conjunction with Demand Response in downstate zones as a mechanism to mitigate the costs of the N-2 Contingency dispatch and the “Gas-Oil Fuel switching” for gas contingencies. Grid connected storage is assumed to be CAES or other large scale technology and the cost parameters for CAES are used as representative today. The benefit from reducing the N-2 contingency is based on (a) the availability of grid connected storage for 0.25 hours duration as above until Demand Response is available to reduce demand and relieve the contingency. Thus the benefit is limited by (a) the amount of grid connected storage deployed and (b) the amount of DR available via Smart Grid / AMI. (AMI required in order to meet the 15 minute guaranteed response requirement).

The gas-oil benefit is similarly limited by the amount of storage and the amount of DR available.

In both the N-2 and gas-oil cases the total maximum benefit of $30M is based on NY ISO 2009 Market data.

The amount of grid connected storage deployed is an Implementation decision and varies from scenario to scenario.

AMI Costs

AMI DATA

	Cost/unit		# of units	Total costs
Residential Meters	$ 110	/ meter	6,897,087	$ 758,679,570
Commercial Meters	$ 310	/ meter	1,032,105	$ 319,952,550
Industrial Meters	$ 2,500	/ meter	8,779	$ 21,947,500
Meter Cost				**$ 1,100,579,620**
Residential Disconnect Switch	$ 20	/ meter	6,897,087	$ 137,941,740
Commercial Disconnect Switch	$ 60	/ meter	1,032,105	$ 61,926,300
Industrial Disconnect Switch	$ 500	/ meter	8,779	$ 4,389,500
Disconnect Switch Cost				**$ 204,257,540**
Residential Gas Meter	$ 130	/ meter	5,172,815	$ 672,465,983
Commercial Gas Meter	$ 350	/ meter	774,079	$ 270,927,563
Industrial Gas Meter	$ 4,000	/ meter	6,584	$ 26,337,000
Gas Meter Cost				**$ 969,730,545**
Residential Comms	$ 50	/ meter	6,897,087	$ 344,854,350
Commercial Comms	$ 100	/ meter	1,032,105	$ 103,210,500
Industrial Comms	$ 250	/ meter	8,779	$ 2,194,750
Communications Cost				**$ 450,259,600**
IT Costs				$ 240,000,000

These are before adjustments to salary / meter cost inflation. In the master calculation these costs were inflated annually through 2025.

NOTE that the labor content of installation appears here as a cost and the in-state labor content also appears as a benefit under “economic development”

AMI Cost Estimation Additional Notes

Per meter costs are in line with National Grid and Con Edison filings as well as other national filings/projects. Forward cost reductions as expected in the industry (as much as 50%) are NOT factored in. Costs are inclusive of installation.

Full cost of disconnects for all electric and gas meters is included (per Con Ed and National Grid even though no benefits are calculated from these devices)

Gas meters are included so that benefits of AMR to utility (reading costs) can be included

IT costs are in line with Con Edison and National grid filings (and others) extrapolated for all state utilities

Communications costs are estimated at $50, 100, 250 for residential, commercial, and industrial meters respectively. (lower densities drive higher unit costs)

Smart Charging Benefits

Smart Charging Data Inputs			Source
Total Cars	8,940,000		NY DOT
Total Comm. Vans	1,200,000		Estimate
Total Vehicles	10,140,000		
Total EV Cars 2025	536,400		6% of Total Cars
Total EV Vans 2025	240,000		20% of Total Commercial Vans
Car Load w/o Smart Charging	5.63	kw	IRC Study
Car Load w/ Smart Charging	0.63	kw	IRC Study
Comm. Vans load w/o Smart Charging	7.03	kw	IRC Study
Comm. Vans load w/ Smart Charging	0.78	kw	IRC Study
Smart Charging Delta Per Car	5.00	kw	
Smart Charging Delta Per Van	6.25	kw	

The cost of smart charging is the cost of an AMI point (meter, communications, installation) for every vehicle and every 10 fleet vans. The benefit is derived from the IRC study data for NY modified by the annual projected penetration (base scenario penetration of EV shown below as vehicles / yr) . The calculated smart charging peak shaving is used to calculate the energy market price savings effect similarly to the way that DR price effects are calculated.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cumulative Number of Cars															
Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suburban	0	2,950	8,851	17,701	29,502	44,253	64,904	88,506	118,008	147,510	177,012	206,514	236,016	265,518	295,020
Urban	0	2,146	6,437	12,874	21,456	32,184	47,203	64,368	85,824	107,280	128,736	150,192	171,648	193,104	214,560
Total	0	5,096	15,287	30,575	50,958	76,437	112,108	152,874	203,832	254,790	305,748	356,706	407,664	458,622	509,580
Cumulative Number of Vans															
Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suburban	0	960	2,880	5,760	9,600	14,400	21,120	28,800	38,400	48,000	57,600	67,200	76,800	86,400	96,000
Urban	0	1,440	4,320	8,640	14,400	21,600	31,680	43,200	57,600	72,000	86,400	100,800	115,200	129,600	144,000
Total	0	2,400	7,200	14,400	24,000	36,000	52,800	72,000	96,000	120,000	144,000	168,000	192,000	216,000	240,000
Smart Charging Benefit (MW)															
Rural	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suburban	0	21	62	125	208	311	457	623	830	1,038	1,245	1,453	1,660	1,868	2,075
Urban	0	20	59	118	197	296	434	592	789	986	1,184	1,381	1,578	1,776	1,973
Total	0	40	121	243	405	607	891	1,214	1,619	2,024	2,429	2,834	3,238	3,643	4,048

Incremental Distributed Resource Penetration

DER DATA

Retail Residential Rate ($/kWh)	0.15
Retail Commercial Rate ($/kWh)	0.12
kWH / yr	
Residential Usage (kWh/year)	4,637
Commercial Usage (kWh/year)	34,778
REC	0.08
Residential Unit Size	4
Commercial Unit Size	30
Cost per Watt	4.21
Rebate per Watt	1.75

Basic Distributed Photovoltaic cost and incentive data is shown to the left. This data is subject to economic inflation and to technology cost improvements / deflation annually. This data is used to develop DER payback models for residential and commercial customers without and with dynamic pricing based on net metering, access to wholesale hourly energy prices, and AMI. The value difference between DER production under flat tariffs and hourly pricing is assume to be 5% on an annualized basis (this is likely conservative). The two payback calculations are each passed through a customer adoption model (Weibull function) that derives annual adoption as a function of payback time in years. The difference in adoption rates is ascribed to the Smart Grid AMI and dynamic pricing capabilities.

The penetration is limited by the available pool of residential and commercial customers that (a) have AMI and (b) have access to dynamic pricing.

The DER resources contribute to benefits in two ways: first, a market energy price savings and energy volume savings is computed based on DER production. Second, DER production on a feeder reduces Distribution Capex to some extent (reduced load growth) and this is considered. The extent to which DER penetration above consumer maximum load is necessary to obtain peak reduction is not a factor; it is assumed that under dynamic pricing consumers will reduce consumption when the DER is not producing (rainy day) and that such will not tend to correlate heavily with peak days.

Distributed Storage

Storage Size (KWH) and Benefit Data

Geography / Class	**Reliability**	**Duration (hours)**	**Energy Peak Shifting**	**Duration (hours)**	**Distribution Capex Deferral**	**Duration (hours)**
Rural - Residential	Y	2	Y	4	Y	4
Rural - Commercial	Y	2	Y	6		
Rural - Industrial	Y	2	Y	6		
Suburban - Residential	Y	2	Y	4	Y	6
Suburban - Commercial	Y	2	Y	6		
Suburban - Industrial	Y	2	Y	6		
Urban - Residential	N		Y	6	Y	6
Urban - Commercial	N		Y	6		
Urban - Industrial	N		Y	6		

Y/N are indicative of whether to count the benefit for this geography / customer class. Durations (in hours) are duration required to achieve benefit. (value of reliability is entered elsewhere - same as DA / SA reliability benefit.) Value of peak shaving is calculated similarly to dynamic pricing in terms of energy market savings. Value of distribution capex is based on kw size with minimum duration required. Payback calculations use this data and cost data (cost inputs) as inputs to a penetration model for consumers and for utilities. Tax incentives factor in.

It is assumed that consumers and utilities invest in distributed storage based on reliability, energy savings, and capital deferral effects. A payback model and adoption model similar to the PV models is used in both cases to determine the adoption rate for distributed storage among utilities and consumers. No consumer direct benefit from distributed storage acquired by the consumer is claimed in the roadmap – it is treated like all other “behind the meter” technology adoptions where the costs and benefits accrue directly to the consumer. The utility realizes energy cost savings and capital deferral from distribution peak shaving. (reliability benefits are insignificant in these calculations) If the utility only realizes capital deferral savings the adoption rates are very low; but if the utility is allowed to realize the energy time shifting / peak shifting benefits as well the adoption rates become significant.

Storage costs for this purpose are assume to be LI-Ion costs for suburban and residential customers which are high today but are decreasing rapidly. Commercial and urban residential customers are assume to use the ICE technology, and utilities also have access to large scale units if deployed in substations. Data for these technologies is shown in the “Transmission Automation – Grid Connected Storage” slide.

Improved Cost Management and Customer Satisfaction

Lower Customer Electric Bills

- Reduced T&D rates reflecting utility cost savings
- Lower energy commodity cost with reduced LBMP
- Conservation based on awareness of usage
- Response to Time-Based Pricing
- Incentives for appliance control
- Detection of malfunctioning systems or appliances

Yellow shading denotes 'soft" benefits throughout

Lower Customer Bills

5.1 Lower Customer Bills				
5.1.1 Peak Reduction and Conservation		%	<< Estimates from Brattle Report	
Annual LBMP+Capacity Costs	$ 11,000,000,000			
Market Cost Savings from peak savings	$ 171,300,000	1.56%		
Savings from reduced usage	$ 220,000,000	2.00%	can vary - see common assumptions	
Price savings from lower usage	$ 187,000,000	1.70%	<< Backed into this number from Total=	
Total Market-Based Savings (with Conservation)	**$ 578,300,000**		$578,900,000	
5.1.2 Conservation Part of 5.1.1	$407,000,000			
5.1.2 Loss Reduction				
Annual LBMP	$ 7,800,000,000			
Potential loss reduction		1.00%	can vary - see common assumptions	
DA Downstate saturation		100.00%	97240	
DA Upstate saturation		100.00%	69436	
Downstate 2008 GWh	97,240			
Upstate 2008 GWh	69,436			
Weighted Average DA Saturation		100.00%		
Reduced Losses	**$ 78,000,000**			
Total 5.1	**$ 656,300,000**			

Gas conservation savings of 1% of total state natural gas consumer costs: ($7,643,090 following Gas AMI deployment)

Lower customer energy bills - notes

Reduction in energy wholesale costs via peak reduction come from NY ISO Brattle report. (the LBMP reduction). It is assumed that these reductions are passed on as is to the consumers. This report assumed 100% penetration of TOU or dynamic pricing rate structures for energy, note.

Because the peak shaving savings are analyzed above on a nodal basis there are no additional congestion savings from peak shaving.

Conservation savings are at average prices and assume T&D rate decoupling (no reduction in wires charges)

Conservation savings also have a price impact a la peak shaving.

Brattle group report had 10-14% peak reduction (varied during year) as a result of dynamic pricing, note.

Distribution loss reduction also reduces net energy bill. The baseline estimate of 1% is reduced by DA penetration assumptions upstate and downstate.

Increased Customer Satisfaction

- More automated transactions with utility
- More control of prices and services
- Improved customer service (from utility and third party suppliers)
- Increased Sustainability and Green Energy awareness and access
- Accurate meter readings, with fewer estimated bills

No quantitative benefits claimed here. Also, benefits of lower non-payments are not calculated.

Improved Cost Management and Customer Satisfaction

Lower Market-Based Cost Due to Distributed Energy Resources

Wholesale Market Savings

- Increased ability to manage loads in high priced periods with more distributed energy resources and demand response.
- Lower capacity requirements due to more dispatchable DR
- Lower reserves and other ancillary requirements, especially with regard to increased RPS
- Accelerated retirement of older plant
- Reduced / deferred expansion of conventional generation
- Increased access to external renewable resources (Canada, etc.)

Estimated DER Benefits	**$000 / year**
Low Case	
Market cost savings from loading order changed	$323,000
Reduce for Peak Savings claimed elsewhere	50.00%
(Lower Customer Bills)	
Total Low Case Savings	$161,500
High Case	
Defer Incremental Transmission Expansion Cost	$400,000
Number of years of Deferral	10
Incremental High Case Savings	$40,000
Total DER Benefits	$201,500

Only 50% of the full value of market savings from load order changes are attributed to DER in the base case scenario. Transmission capex deferral is from state energy plan adjusted for DER penetration achieving renewables w/o transmission impact.

Reduced Cost of Locational Reserves

Wholesale Market Savings

- Reduced cost of locational reserves
- Benefits of better forecasting
- Increased transmission capacity utilization
- Lower costs for unscheduled outages (congestion)
- Increased access to external renewable resources (Canada, etc.)

Benefit of going from N-2 to N-1	$	30,000,000
Benefit of avoiding gas-to-oil fuel contingency	$	30,000,000

Congestion savings already accounted for in conservation, DR, and renewables calculations. However, savings due to avoided N-2 contingency dispatch is estimated at $30M / yr. (Con Edison 2009 data; validated by NY ISO.) A combination of automatically controllable DR (ADR), storage, and quick start units in congested zones could alleviate these costs.

State synchrophasor projects may result in new applications that allow higher utilization. Benefits of these are identified in deferred transmission capital expenditures rather than as reduced congestion costs, note.

Improved Cost Management and Customer Satisfaction

Access to New Products and Services

- More choices of rate structures and value propositions
- Access to broader set of advanced products (heating, AC, appliances, microbiological controls for air and water quality, home entertainment)
- Communications technologies in place for Smart Grid can support other activities

Enhanced Power Quality & Reliability

Smart Grid Devices on the T&D System

- T&D Utility Company Savings
  - Asset Management
    - > decreased failures
    - > decreased maintenance
    - > deferred capital investments
  - Efficient Outage Response
  - Reduced T&D losses
  - Improved Power Factor/Quality
- Quicker utility response to fires, storms.
- Avoidance/management of widespread outages
- Reduction in traffic accidents involving utility vehicles (meter reading, outage spotters)

Distribution losses already computed in "customer bill" savings. Transmission loss reduction estimated at $9,700,000 / yr per a NY ISO study. Monitoring benefits on failures and deferrals are from various KEMA studies including an SA analysis done for National Grid in 2005-06. Distribution capex deferrals are from cost of capex for incremental load from Con Edison and National Grid pro rated for assumed urban and non-urban infrastructure. Deferral is a result of peak shaving and conservation savings on distribution loading.

Deferred Distribution CAPEX				
			feeder inc capex / MW	
Substation Automation monitoring benefit/yr	**$ 8,000,000**		urban	suburban / rural
Benefit from deferral of transformer and breaker upgrades/yr	**$ 20,000,000**		$/MW	MW/yr
Benefit from deferral of distribution circuit upgrades/yr	**$ 120,000,000**		$600,000	$400,000
Total benefit from DA/SA per year/yr	**$ 148,000,000**		# stations	400
5.9 Reduced Distribution OPEX				
Labor saving due to better monitoring and detection/yr	**$ 1,000,000**			

Enhanced Power Quality & Reliability

Asset/Infrastructure Optimization

- Reduced frequency and duration of outages
- Improved power quality for high tech customers
- Reduced costs of work interruption to businesses
- Reduced labor costs for emergency personnel that may be required to protect business, direct traffic, and carry out other government functions during outages.

5.2 Improved Reliability		Residential	Commercial	Industrial
CAIDI	1.08			
$/hour customer outage cost - Residential		$ 3.30	$ 619.00	$ 12,487.00
# of customers by class	7,937,971	6,897,087	1,032,105	8,779
# of customers served	7,701,361	6,691,503	1,001,341	8,517
Business as Usual				
# customers served x CAIDI		7,226,823	1,081,448	9,199
x cost	$ 808,129,033	$ 23,848,517	$ 669,416,264	$ 114,864,252
Smart Grid				
Transmission % of CAIDI	0.216	20.00%		
CAIDI improvement with 100% SG	0.071	33.00%		
CAIDI with % of Transmission upgraded	0.163	75.00%		
Distribution % of CAIDI	0.864	80.00%		
CAIDI improvement with 100% SG	0.173	20.00%		
CAIDI with % of DA	0.691	100.00%		
# customers served x CAIDI with SG	0.854	5,712,804	854,885	7,272
x cost	$ 638,826,001	$ 18,852,252	$ 529,173,557	$ 90,800,191
Total 5.2 Savings	**$ 169,303,032**	$ 4,996,264	$ 140,242,707	$ 24,064,061

Reliability Benefits - notes

- On an annual basis, it is estimated that 80 percent of interruptions originate in the distribution system, and the remaining 20 percent derive from transmission problems. (Source: 3,4,5)
- Where smart grid is deployed, transmission disturbances will decline by 33 percent, and distribution disturbances will decline by 20 percent. (Source: 3)
- Saturation assumptions: 75% transmission improvement, 75% and 50% distribution automation in downstate and upstate NY, respectively.
- Consumer cost of 1 hour interruption = $3.30 Residential; $619 Commercial; $12,487 Industrial. (Source: 1)
- 2008 CAIDI per customer served = 1.08 (Source: 2)

- Freeman, Sullivan & Co., Estimated Value of Service Reliability for Electric Utility Customers in the United States, LBNL, June 2009.
- 2008 CAIDI from NY Public Service Commission reliability web site (excluding storms, including ConEd)
- Baer, Fulton and Mahnovski (RAND), Estimating the Benefits of the GridWise Initiative, PNNL, May 2004
- EPRI, Value Assessment, Consortium for Electric Infrastructure to Support a Digital Society, July 10, 2001
- Edison Electric Institute, 2000 Reliability Report, June 2001
- NY PSC Reliability Statistics for 2008
- Pacific Northwest National Laboratory, for US DOE, The Smart Grid: An Estimation of the Energy and CO2 Benefits, January 2010

Enhanced Power Quality & Reliability

Utility Metering Savings

- Reduced Meter reading costs

AMI operational savings per customer	$	2.0
AMI operational savings	**$**	**15,402,722**

NOTE: Metering savings are dependent upon having both gas and electric meters upgraded for AMI. Thus gas meter costs are included. $2/year is a blended average reflecting low urban meter reading costs. (This may be too low a figure considering that national non-urban averages are $1.5-2 / month)

Full cost of disconnects is included in both cases although no benefits are claimed given current state law.

Cost of disconnects is included because a future retrofit would be prohibitive should state law be modified and the benefits are substantial

Positive Societal/Environmental Impact

Job Creation

- Jobs created by new infrastructure requirements, and replacement of lower value jobs (meter reading) with higher value jobs (SG technicians)
- Attraction/retention of businesses in state (because of lower energy costs, better reliability, “greenness”
- Development of high value SG ecosystem jobs in state
- R&D, manufacturing, test, support

$ / job	$75,000	from GridWise Alliance Report
% of deployment spend that is labor	33%	
% of deployment labor spend that is "local"	46%	
% of cumulative spend that drives ongoing OPEX labor	12%	

Positive Societal/Environmental Impact

Adoption of Electric Vehicles

- Management of Electric Vehicle charging loads and lower costs to accommodate EV charging infrastructure
  - Increased penetration of EV and reduced gasoline costs (not credited to Smart Grid)
  - Deferred distribution capex thanks to smart charging reduction of increased late afternoon / early evening peak load increases

	Smart Charging Benefits					
Total automobiles in New York State	8,940,000			<< NYSDOT tbc		
Projected EV penetration	6%		0.48%			
Electric vehicles	536,400		43,000	<< IRC Study		
Load without smart charging (MW)	3,019		242	<< IRC Study		
Load with smart charging (MW)	337		27	<< IRC Study		
Difference	2,682		0.11	RATIO smart/dumb chg		
Total Fleet Vehicles "Vans" in NY	1,200,000	estimate				
Projected EV Penetration by 2025 Total	20.00%					
Fleet EV load Differerence	240000	EV Car load			5.63	EV load in kW
Load w/o smart charging	1688	Van charging load	1.25		7.03	van EV laod in kW
Load w smart charging	188	as fraction of EV		assumes same smart charging benefit as for cars		
Fleet EV load Differerence	1,500					
Incremental distribution capacity ($/MW)	$ 600,000		25%	% of the EV driven by SG for fuel savings calcs		not used PHEV BCA from AMI
Circuits impacted	75%	estimate				
Differential w & w/o smart charging	**$ 1,881,900,000**	drives PHEV benefits from AMI for smart charging				
Adjusted for distance from feeder	**$ 1,129,140,000**		0.60	<< ORNL		
Annual Savings from avoided capital recovery	**$ 135,496,800**					

Positive Societal/Environmental Impact

Enhanced Quality of Life

- Displacement of traditional generation by renewable sources
- Avoidance of additional reserves / ancillaries all in prior calculations
- Avoidance of degraded heat rates from renewable firming
- Smog reduction resulting from faster EV penetration not a SG credit if EV assumed
- Use of AMI to measure usage and calculate consumers' carbon footprints.
- CO2 Reductions arising from reduced / altered fossil fueled generation as a result of renewables and conservation
- Criteria Air Pollutant Reductions
- Ability to isolate disturbances
- Reduced dependence on traditional energy sources
- Improved ability to manage linked infrastructure dependencies (power/water/gas/telecommunications)
- Fuel diversity

Positive Health and Environmental Impacts

Conservative estimate of NY Benefit	5%		
Total US Benefit attibutable to smart grid	359,000,000	tons	<<PNNL
NY Benefit	17,950,000	tons	
Economic value of avoided emissions	$20.00		<< Synapse & KEMA
Total Savings	**$ 359,000,000**		