


Distributed Generation Standard Contracts and Renewable Energy Fund

Jobs, Economic and Environmental Impact
Study

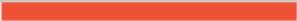
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Executive Summary

The Rhode Island Office of Energy Resources (OER) and Commerce RI have engaged *The Brattle Group* to conduct a study to help meet the Rhode Island Distributed Generation Standard Contracts Law as amended, July 2013, requirement that the OER submit to the Governor, the President of the Senate, and the Speaker of the House of Representatives, a study addressing the annual jobs, economic impact, and environmental impacts attributable to the distributed generation standard contract program (DGSC).

In brief, the study finds that the DGSC and REF programs under three scenarios studied will result in net positive economic output, job gains, criteria pollutant¹ emissions reductions, carbon emissions reductions, and positive state tax revenues over the period 2014-2038. These impacts are relative to a scenario without DGSC and REF programs and incorporate both the positive and negative impacts of the DGSC and REF programs. The three scenarios reflect three levels of DGSC capacity and two levels of REF funding. Scenario 1 adds 160 MW of DGSC renewable capacity by 2019 in addition to the 40 MW of DGSC renewable capacity already under contract for a total of 200 MW. This scenario also includes 5.46 MW of residential and commercial solar developed through the REF program. Scenario 2 adds 200 MW of DGSC renewable capacity by 2019 in addition to the 40 MW of DGSC renewable capacity already under contract for a total of 240 MW. This scenario also includes 5.46 MW of residential and commercial solar developed through the REF program. Scenario 3 adds 1000 MW of DGSC renewable capacity by 2024 in addition to the 40 MW of DGSC renewable capacity already under contract for a total of 1040 MW. This scenario also includes 10.17 MW of residential and commercial solar capacity developed through the REF program. Table 1A shows the average annual impacts of the programs. Economic output, state tax, and emissions damage reductions are shown in millions of 2014 USD. Employment values are shown as full-time equivalent jobs². These impacts can be thought of as the average annual differences between the given program scenario and a scenario without the programs from 2013 to 2038. For example, on average there will be 246 more full-time equivalent jobs each year under the 160 MW DGSC scenario than under a scenario without the DGSC and REF programs (these numbers are not additive over time). Table 1B shows the net present value³ of the program impacts.

¹ Criteria pollutants are defined as pollutants specifically regulated under the Clean Air Act.

² A full-time equivalent job is defined as an employee who worked 2,080 hours (40 hours/week * 52 weeks) in a year. See <http://www.irs.gov/uac/Small-Business-Health-Care-Tax-Credit-Questions-and-Answers:-Determining-FTEs-and-Average-Annual-Wages>

³ A real discount rate of 2.5% is used throughout this report to calculate net present value. This reflects the difference between a nominal risk free rate of 4.8% and an inflation rate of 2.3%. See *Blue Chip Economic Indicators*, Volume 39, No. 3. March 10, 2014.

Table 1A: Average Annual Impacts of DGSC and REF Programs

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Economic Output (\$2014 MM)	\$30.65	\$36.40	\$135.13
Employment (FTE Jobs)	246	293	1,095
State Tax Impacts (\$2014 MM)	\$1.05	\$1.24	\$4.40
CO2 Damage Cost Reductions (\$2014 MM)	\$0.70	\$0.83	\$3.13
SO2 Damage Cost Reductions (\$2014 MM)	\$0.09	\$0.11	\$0.45
NOX Damage Cost Reductions (\$2014 MM)	\$0.30	\$0.35	\$1.33
PM-10 Damage Cost Reductions (\$2014 MM)	\$0.05	\$0.06	\$0.24
PM-2.5 Damage Cost Reductions (\$2014 MM)	\$0.77	\$0.91	\$3.42

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.

Table 1B: Net Present Value Impacts of DGSC and REF Programs (\$2014 MM)

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Economic Output	\$556	\$658	\$2,340
State Tax Impacts	\$16	\$19	\$63
CO2 Damage Cost Reductions	\$13	\$15	\$54
SO2 Damage Cost Reductions	\$2	\$2	\$7
NOX Damage Cost Reductions	\$5	\$6	\$23
PM-10 Damage Cost Reductions	\$1	\$1	\$4
PM-2.5 Damage Cost Reductions	\$14	\$16	\$60

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.

These positive impacts do, however, come at a cost to ratepayers. As shown in Table 2A, the average annual increase to ratepayers is \$17 million under the 160 MW DGSC scenario after accounting for the modest rate reductions that arise from price suppression caused by increasing energy supply through the program and emissions allowance cost reductions. On an NPV basis, ratepayer rate increases total \$354 million over the period 2013-2038 under the 160 MW DGSC scenario as shown in Table 2B. While this is a substantial cost, it should be placed in context with the economic activity generated over the same period of \$556 million on an NPV basis and the environmental benefits and employment gains.

Finally, the introduction of distributed generation may have additional positive impacts including reduced electricity transmission and distributed costs (T+D) by avoiding new construction and protection against natural gas price spikes through greater fuel diversity. It is

difficult to estimate T+D savings because they are site specific, but studies have indicated savings could be approximately \$4/MWh - \$26/MWh. Diversity savings can be valued at \$5 million on an NPV basis over the period 2013-2038 based on current projections of natural gas prices under tight market conditions. These positive impacts could be at least partially offset by increased grid management costs attributable to a more diverse and less centralized electric grid. Studies suggest that these costs will range between \$2.50/MWh and \$10.90/MWh.

Table 2A: Average Annual Ratepayer Impacts of DGSC and REF Programs (\$2014 MM)

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Ratepayer Price Suppression Savings	\$0.75	\$0.90	\$3.44
Ratepayer Program Costs	-\$17.93	-\$20.94	-\$136.83
Net Ratepayer Impacts	-\$17.18	-\$20.04	-\$133.39

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.

Table 2B: Net Present Value Ratepayer Impacts of DGSC and REF Programs (\$2014 MM)

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Ratepayer Price Suppression Savings	\$13	\$16	\$59
Ratepayer Program Costs	-\$367	-\$427	-\$2,680
Net Ratepayer Impacts	-\$354	-\$412	-\$2,621

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.

Introduction

A. STUDY OBJECTIVE

The Rhode Island Office of Energy Resources (OER) and Commerce RI have engaged *The Brattle Group* to conduct a study to help meet the Rhode Island Distributed Generation Contracts Law's, as amended July 2013, requirement that the OER submit to the Governor, the President of the Senate, and the Speaker of the House of Representatives a study addressing the annual jobs, economic impact, and environmental impacts attributable to the distributed generation standard contract program (DGSC). The impacts of the Renewable Energy Fund (REF) are also included in this study.

This study measures these impacts on an annual and project life basis under three scenarios. Scenario 1 reflects a DGSC program that adds 160 MW of DGSC renewable capacity by 2019 in addition to the 40 MW already under contract. This scenario, which we will refer to as “160 MW DGSC”⁴ throughout the report, also includes \$800,000 of annual REF funding through 2018. Scenario 2 adds 200 MW of DGSC renewable capacity by 2019. This scenario, which we will refer to as “200 MW DGSC” throughout the report, also includes \$800,000 of annual REF funding through 2018. Scenario 3 adds 1000 MW of DGSC renewable capacity by 2024. This scenario, which we will refer to as “1000 MW DGSC” throughout the report, also includes \$1,600,000 of annual REF funding through 2018. The OER anticipates that solar will comprise 90%, wind will comprise 5%, hydro will comprise 2.5%, and anaerobic digesters will comprise 2.5% of capacity added under the DGSC program. Scenarios 1 and 2 include 5.46 MW of solar capacity attributed to REF. Scenario 3 includes 10.17 MW of REF related solar capacity. The three scenarios are outlined below. We compare these three scenarios to a baseline scenario throughout the report where there is neither a DGSC nor REF program.

Table 3: MW Installed by Year and Source for 160 MW DGSC Scenario

Energy Source	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Solar	15.31	22.31	23.42	36.94	36.97	37.00	13.50	0.00	0.00	0.00	0.00	0.00
Wind	0.81	1.19	1.25	2.00	2.00	2.00	0.75	0.00	0.00	0.00	0.00	0.00
Hydro	0.40	0.60	0.63	1.00	1.00	1.00	0.38	0.00	0.00	0.00	0.00	0.00
Anaerobic digestion	0.40	0.60	0.63	1.00	1.00	1.00	0.38	0.00	0.00	0.00	0.00	0.00

Note:

This scenario includes \$800,000 of REF funding, which goes into solar installations.

Table 4: MW Installed by Year and Source for 200 MW DGSC Scenario

Energy Source	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Solar	15.31	22.31	36.92	36.94	36.97	37.00	36.00	0.00	0.00	0.00	0.00	0.00
Wind	0.81	1.19	2.00	2.00	2.00	2.00	2.00	0.00	0.00	0.00	0.00	0.00
Hydro	0.40	0.60	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00	0.00	0.00
Anaerobic digestion	0.40	0.60	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00	0.00	0.00

Note:

This scenario includes \$800,000 of REF funding, which goes into solar installations.

Table 5: MW Installed by Year and Source for 1000 MW DGSC Scenario

Energy Source	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Solar	15.31	23.19	91.84	91.89	91.94	92.00	90.00	90.00	90.00	90.00	90.00	90.00
Wind	0.81	1.19	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Hydro	0.40	0.60	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Anaerobic digestion	0.40	0.60	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50

Note:

This scenario includes \$1,600,000 of REF funding, which goes into solar installations.

⁴ Note that we use “DGSC” and “DGC” interchangeably throughout the report.

B. STRUCTURE OF REPORT

This report is organized into nine sections including the introduction. Section two provides a description of the DGSC and REF programs. Section three reviews the methodology employed in the analysis. Section four describes the data and reviews key assumptions used in the analysis. Section five presents the results of the analysis. Section six provides our conclusions. The main focus of the report is the 160 MW DGSC scenario. Sections 7-9 provide Appendices A, B, and C. Appendix A presents supplementary tables for the 200 and 1000 MW DGSC scenarios. Appendix B presents annual environmental impacts. Appendix C presents a summary of results under a case where gas prices are higher than expected.

II. Program Description

Rhode Island's efforts to promote renewable energy include two key programs: 1) the Distributed Generation Standard Contract (DGSC) program and 2) the Renewable Energy Fund (REF). The DGSC program requires that National Grid enter into fifteen year renewable energy contracts with private landowners, businesses, and municipalities at a set and fixed price. Anaerobic digestion, solar photovoltaic, hydro, and wind technology projects are eligible. Since the first enrollment in December 2011, 23.5 MW of wind and solar projects have been committed to the DGSC program. A majority have been solar projects with two DGSC contracts being awarded to wind turbine projects through the first three years of the program. Projects have or are scheduled to be built in multiple municipalities, including Providence, Coventry, Portsmouth, West Greenwich, North Kingstown, Charlestown, Richmond, Warwick, Jamestown, West Warwick, East Providence, Middletown, North Smithfield, Johnston, and Cranston. To date, projects have been proposed in 30 of the 39 municipalities. In 2014, approximately 16.5 MW are anticipated to be awarded to wind, solar photovoltaic, small scale hydro, and anaerobic digestion projects.

The prices for these contracts have ranged from \$148/MWh to \$310/MWh for solar. National Grid administers the annual program and receives administrative support and remuneration for operating the annual program. The OER and Distributed Generation Board provide oversight and develop the annual DGSC program and goals in coordination with National Grid. In return for entering into these contracts, National Grid receives a recoupment fee on contract values and an annual administrative fee of \$500,000, which are funded through electric rates⁵. The program is currently authorized to approve up to 40 MW of renewable energy capacity by 2014. Program expansion is currently under consideration.

Under the 160 MW DGSC scenario, an average of \$18 million of above market costs, remuneration costs, and administrative costs are passed on to ratepayers from National Grid each

⁵ The administrative fees are paid through 2021 for the 160 MW DGC and 200 MW DGC scenarios. The fees last until 2026 under the 1000 MW DGC scenario. The recoupment fee that National Grid receives is equal to 2.75% of contract revenues. Contracts last fifteen years, so ratepayers only have to cover the recoupment and above market costs faced by National Grid during the contract period.

year. These costs are partially offset by ratepayer benefits such as reduced rates from price suppression and emissions allowance savings, which amount to an average of \$0.75 million each year.

The Renewable Energy Fund provides grants and loans for eligible renewable energy projects to cover preliminary feasibility studies and installation. Funding for this program comes from a surcharge on electric customers bills. Since the REF rules and regulations were approved in December 2012, the fund has distributed \$500,369 to small-scale solar projects and \$153,810 to commercial-scale renewable projects. Commerce RI, which administers the Fund, anticipates annual funding of at least \$800,000 through 2018. Funding could be increased to \$1.6 million if the program's popularity increases. This funding will promote between 5.47 MW and 10.17 MW of solar capacity.

III. Methodology

Determining the impacts of Rhode Island's Distributed Generation Standard Contracts program and the Renewable Energy Fund program requires a comparison of electric capacity, generation costs, transmission and distribution costs, and emissions in the absence of these programs to capacity, generation costs, transmission and distribution costs, and emissions with the programs in place. The observed differences between these scenarios measure the program's impacts. Generation costs include, not only the fixed and variable operating costs (including fuel and taxes) faced by plants, but also other grid service costs and environmental externalities. Differences in these costs, as well as capital costs, have consequences for electricity rates and employment. These consequences, in turn, affect economic development and government tax revenues. The differences also provide a basis to detect and measure other benefits such as energy diversity.

To estimate the impact of the DGSC and REF programs on electricity generation and air quality we rely on two models – an energy capacity planning model and an energy dispatch model. The energy capacity planning model determines which New England plants, if any, will be forced to retire when additional capacity is added to Rhode Island⁶. The energy dispatch model determines which plants will be dispatched each year in order to minimize generation costs and meet demand⁷. This model determines which power plants are utilized (and how much they are utilized) and provides the basis to estimate generation costs and emissions reductions. In turn,

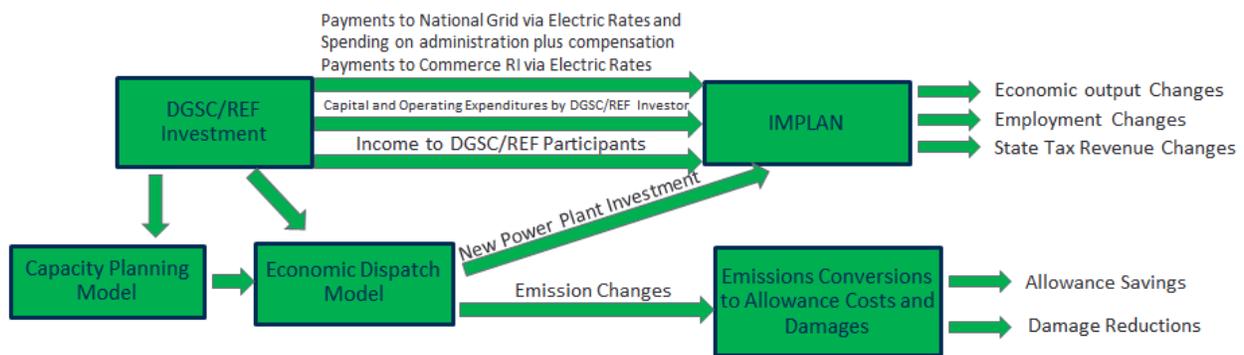
⁶ We take power plant retirements that have already been announced as given. The renewable capacity added by the state's programs is also taken as given. Consequently, additional retirements are limited to capacity that is permanently removed to make room for program renewables.

⁷ The energy dispatch model uses data from National Grid to determine, on average, what percentage of total load falls into each hour of the day for two seasons (winter and summer). These percentages are used to allocate annual demand, as forecasted by ISO-NE, into 48 buckets (two seasons multiplied by 24 hours). For each year, the dispatch model is run for each of these 48 buckets. The results are then weighted by bucket share of consumption.

estimated emissions reductions can be used to estimate pollutant allowance cost and pollutant damage cost reductions.

We estimate economic impacts using IMPLAN, which is an input-output model. IMPLAN is widely used by federal, state, and local agencies to measure the impacts of regulatory changes and major infrastructure investments. IMPLAN measures changes in economic output, jobs, and tax revenues resulting from these changes or investments. The necessary inputs to this model are taken from the capacity planning and dispatch model results as well as program expenditures funded by ratepayers and/or taxpayers and by program participants – investors, businesses, and households. The relationship between the models and spending information is presented in Figure 1.

Figure 1: Flow of Modeling



Investments in renewable plants encouraged by the DCG and REF programs and associated changes in electricity prices result in changes to final demand for goods and services by the residential, commercial, industrial, finance, and utility sectors. Electricity price changes are determined by changes in the generating cost and dispatch and additional charges to finance the DGSC and REF programs. Final demands are also influenced by changes in income to renewable energy participants (investors, businesses, and households) and payments to the participating utility (National Grid) through the DGSC program. IMPLAN produces estimates of economic output, employment and state tax revenues at the state level. Economic output is a measure of economic activity, and here represents a state level GNP reflecting the market value of all goods and services produced in one year by labor and property supplied by residents of the state. Employment impacts are comprised of direct employees associated with manufacturing a good or providing a service (installing solar equipment for example), indirect employees associated with providing goods and services to the manufacturer or primary service provider, and induced employees associated with the demand for goods and services from households who generate additional income as direct or indirect workers.

As shown in Figure 1, the DGSC and REF program influence final demand for goods and services in several ways including:

- 1) capital and operating expenses by program participants (investors, businesses, and households);
- 2) ratepayer expenditures to cover:
 - a) National Grid administrative costs,
 - b) remuneration to National Grid,
 - c) the above market component of the DGSC contracts and,
 - d) subsidies to REF participants;
- 3) ratepayer savings from reduced generation costs and emissions allowance cost reductions;
- 4) spending of income generated by program participants⁸;
- 5) spending by National Grid on DGSC related administrative costs and remuneration;
- 6) capital and operating spending changes in electricity generation by new and existing power plants resulting from the introduction of the renewable program capacity.

IMPLAN accounts for whether spending and investment occur in-state or out-of-state. Table 6 summarizes the percentage of spending on PV construction that takes place in-state. Column 1 represents the share of total construction costs from each category, which sums to 100%. Column 2 represents the share of each expenditure category that is made in Rhode Island.

Table 6: Breakdown of PV Construction Costs

Category	Share [1]	% In-State [2]
Modules	31.72%	0.23%
Installation and Overhead Costs	43.41%	98.13%
Inverters	5.72%	2.41%
Wires, connectors, breakers; etc.	2.54%	4.30%
Mounting (rails, clamps, fittings; etc)	3.95%	5.46%
Permitting and Other Costs	12.65%	84.19%
Weighted Average In-State Share		53.78%

Source:

NREL JEDI Models, IMPLAN

⁸ The income associated with participating in the REF program is equal to avoided energy usage multiplied by the real retail price of electricity. Since we use the real retail price of electricity, we discount at a real rate. The income associated with participating in the DGSC program is equal to contracted generation multiplied by the contract price. Contracts are in effect for fifteen years. After contracts expire, we assume that DGSC participants sell their power on the wholesale market. Contracts are in nominal terms with no escalator provision for inflation, so we deflate post-contract date prices into \$2014. We discount these real contract revenues at the real rate.

IV. Data and Assumptions

We rely on several sources for data and key assumptions. First, we rely primarily on Ventyx’s Energy Velocity for information on plants currently operating in New England and their operating costs, plants expected to be built in New England, and plants expected to retire in New England⁹. We assume that 30 MW from the Block Island offshore wind project will become available to New England by 2016. A list of plants that we expect to retire in New England is below. These plants are expected to retire regardless of the magnitude of the DGSC and REF programs.

Table 7: Summary of Expected Retirements

Plant Owner	Plant Name	State	Unit	Capacity (MW)	Retirement Date	Fuel
Dominion Energy Salem Harbor LLC	Salem Harbor	Massachusetts	GEN3	-165.7	5/31/2014 0:00	BIT
Dominion Energy Salem Harbor LLC	Salem Harbor	Massachusetts	GEN4	-475.5	5/31/2014 0:00	RFO
Entergy Nuclear Vermont Yankee LLC	Vermont Yankee	Vermont	1	-676.1	1/1/2015 0:00	URA
Maine Energy Recovery Co	Maine Energy Recovery Co	Maine	MERC	-22	5/15/2013 0:00	MSW
NRG Montville Operations Inc	Montville Station	Connecticut	UNT5	-35	6/15/2013 0:00	RFO
Penobscot River Restoration Trust	Howland	Maine	HL01	-0.6	1/1/2030 0:00	WAT
Penobscot River Restoration Trust	Howland	Maine	HL02	-0.6	1/1/2030 0:00	WAT
Penobscot River Restoration Trust	Howland	Maine	HL03	-0.6	1/1/2030 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ01	-0.7	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ02	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ03	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ04	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ05	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ06	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ07	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ08	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ09	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ10	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ11	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ12	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ13	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ14	-0.3	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ15	-0.5	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ16	-1.5	1/1/2015 0:00	WAT
Penobscot River Restoration Trust	PPL Veazie Hydro Station	Maine	VZ17	-1.5	1/1/2015 0:00	WAT
Dominion Energy New England LLC	Brayton PT	Massachusetts	GEN1	-241	1/1/2017 0:00	BIT
Dominion Energy New England LLC	Brayton PT	Massachusetts	GEN2	-241	1/1/2017 0:00	BIT
Dominion Energy New England LLC	Brayton PT	Massachusetts	GEN3	-672.6	1/1/2017 0:00	BIT
Dominion Energy New England LLC	Brayton PT	Massachusetts	GEN4	-475.5	1/1/2017 0:00	RFO

Second, we rely on a report from Black and Veatch to determine the construction and operating costs for new plants¹⁰. This group includes plants that are expected to be built according to Ventyx and capacity that will be added under the DGSC and REF programs. Levelized and construction costs excluding subsidies are summarized below. Including subsidies would reduce levelized solar costs by over 25% if the solar investment tax credit (ITC) is 30%. For example, the

⁹ <http://www.ventyx.com/en/solutions/business-operations/business-products/velocity-suite>

¹⁰ Black & Veatch, *Cost and Performance Data for Power Generation Technologies*. February 2012

levelized cost of solar after the 30% ITC falls from approximately \$295/MWh to \$220/MWh in 2013.

Figure 2: Unsubsidized Levelized Cost of Energy by Source and Year (\$2014)

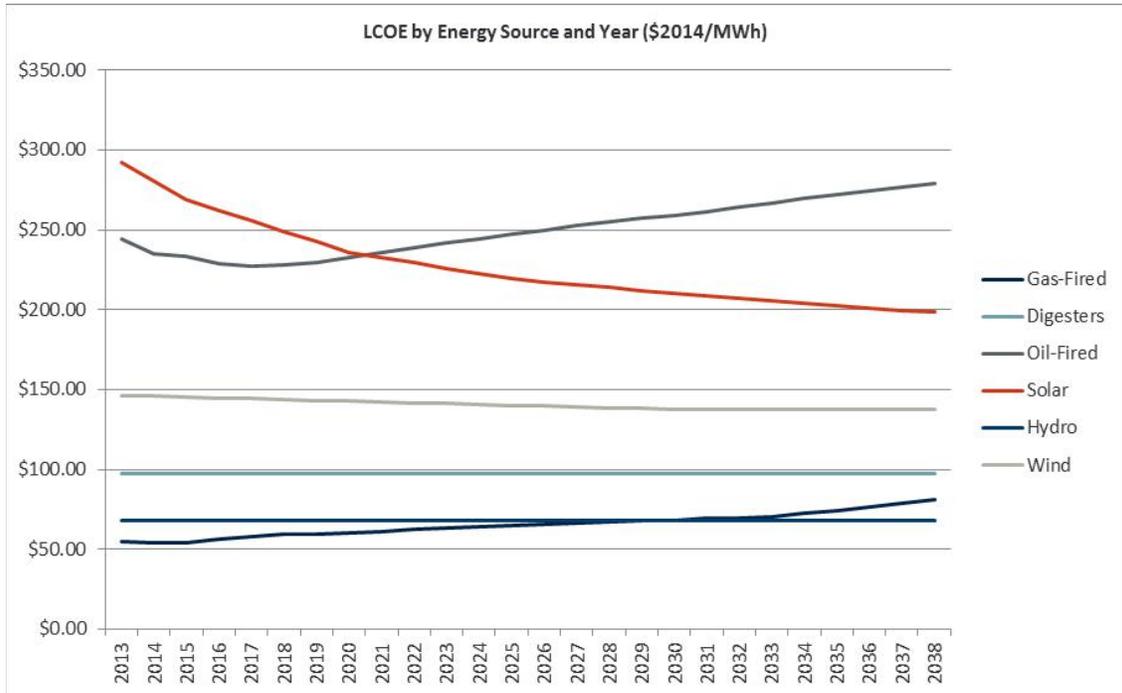
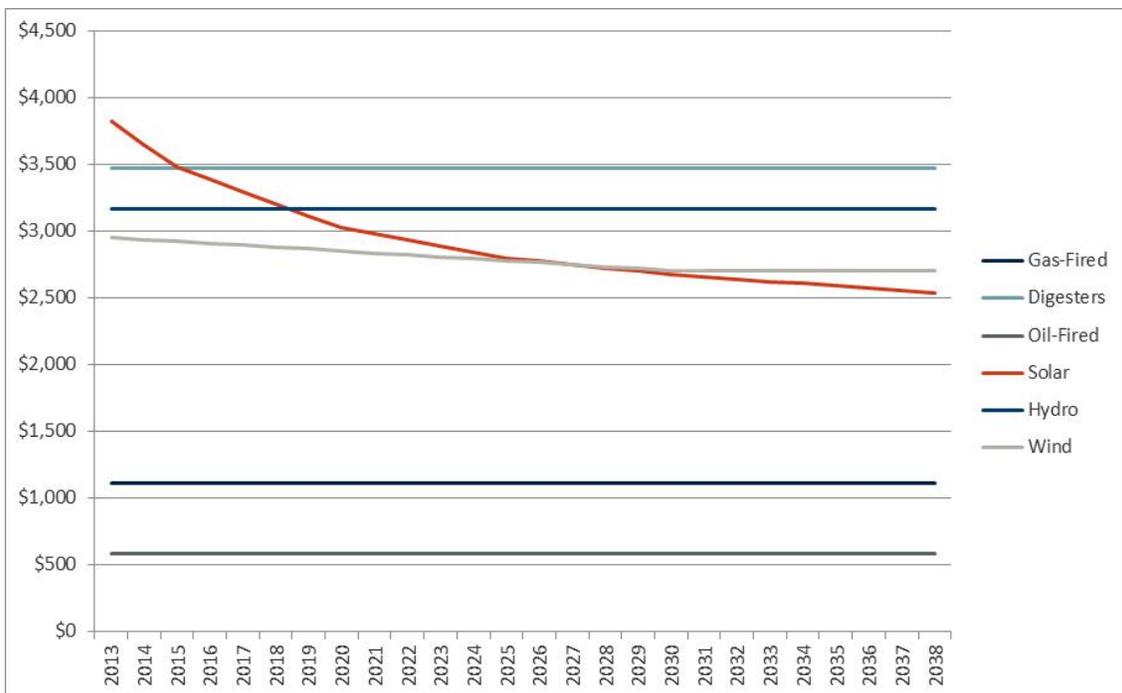
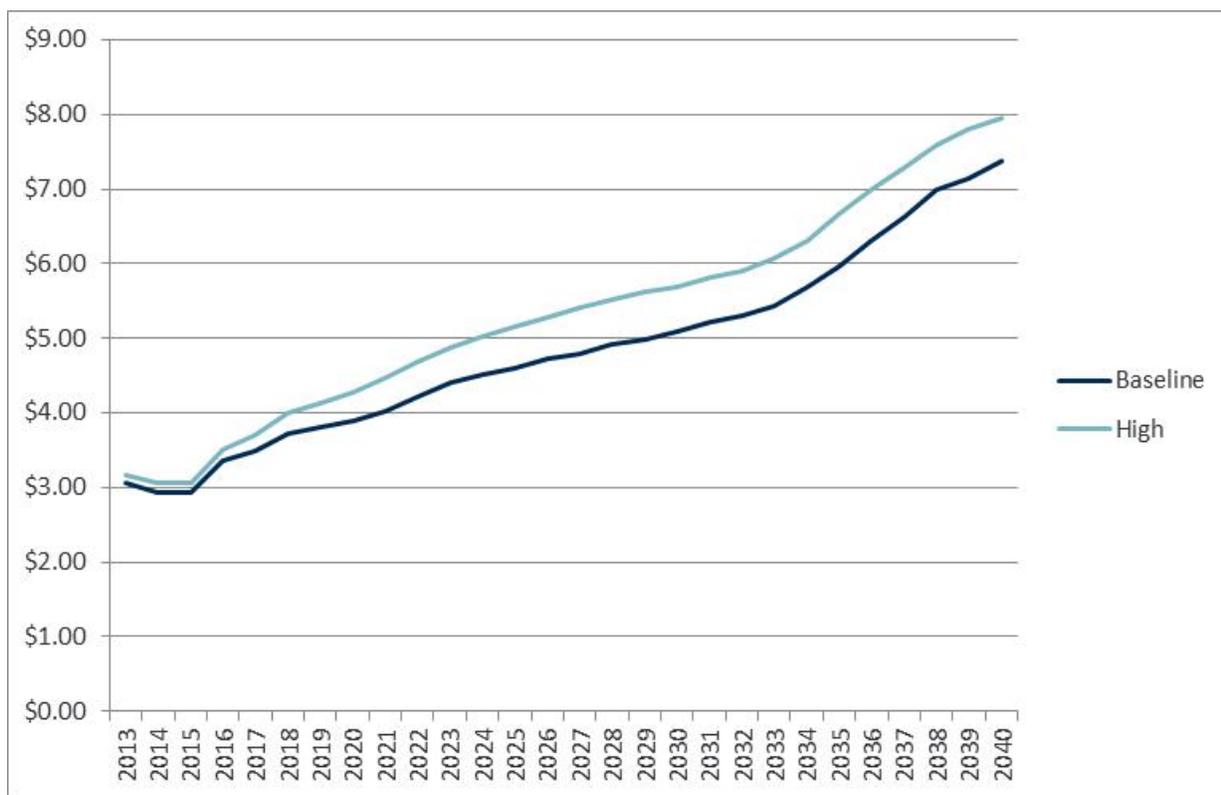


Figure 3: Unsubsidized Construction Costs by Source and Year (\$2014/kW)



Third, we rely on the Energy Information Administration (EIA) for gas, oil, and coal price forecasts. The EIA, which is part of the US Department of Energy, provides publicly available energy industry data, analysis, and forecasts. We consider two natural gas price scenarios, which are shown below. The baseline scenario is consistent with the EIA reference case, and the high scenario is consistent with the EIA high growth case¹¹. In our analysis, these prices are both adjusted upwards to account for New England prices exceeding Henry Hub prices¹².

Figure 4: Henry Hub Natural Gas Price Scenarios (\$2014/mmbtu)



Fourth, we rely on the OER for anaerobic digester, solar, hydro, and on-shore wind capacity factors. Off-shore wind capacity factors come from the 2010 Connecticut Integrated Resource Plan¹³. These are summarized below.

¹¹ EIA, *Annual Energy Outlook 2014*. April 17, 2013.

¹² Henry Hub is a natural gas distribution hub located in Louisiana. It is the pricing point for many natural gas derivative contracts traded on exchanges. Natural gas prices in New England are typically higher than those at Henry Hub.

¹³ The Brattle Group, *Integrated Resource Plan for Connecticut*. 2010.

Table 8: Capacity Factors by Source (%)

Source	Factor
Digesters	51%
Solar	14%
Hydro	50%
On-shore Wind	26%
Off-shore Wind	37%

Fifth, we rely on Ventyx’s Energy Velocity and data from the Commission for Environmental Cooperation’s North American Power Plant Air Emissions project for emissions by plant type. This data is summarized below.

Table 9: Emissions by Plant Type and Pollutant (Tons/MWh)

Source	CO2	SO2	NOX	PM-10	PM-2.5	Mercury
Gas-Fired	0.5781	0.0000	0.0009	0.0002	0.0002	0.0000
Digesters	0.5175	0.0000	0.0002	0.0000	0.0000	0.0000
Oil-Fired	1.3252	0.0093	0.0012	0.0015	0.0012	0.0000
Solar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydro	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Wind	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Sixth, we rely on Synapse’s 2013 Avoided Energy Cost report¹⁴ for emissions allowance costs. This data is summarized below. The allowance prices represent the cost per ton for CO2, SO2 and NOX emission permits. Generators must purchase sufficient allowances to meet emission standards in place for these pollutants.

¹⁴ Synapse, *Avoided Energy Supply Costs in New England: 2013 Report*. July 12, 2013.

Table 10: Emissions Allowance Costs (\$2014/ton)

Year	CO2 Allowances	SO2 Allowances	NOX Allowances
2013	\$2.75	\$0.00	\$26.87
2014	\$4.14	\$0.00	\$26.87
2015	\$5.18	\$0.00	\$26.87
2016	\$6.21	\$0.00	\$26.87
2017	\$7.25	\$0.00	\$26.87
2018	\$8.27	\$0.00	\$26.87
2019	\$9.31	\$0.00	\$26.87
2020	\$10.34	\$0.00	\$26.87
2021	\$10.34	\$0.00	\$26.87
2022	\$10.34	\$0.00	\$26.87
2023	\$10.34	\$0.00	\$26.87
2024	\$10.34	\$0.00	\$26.87
2025	\$10.34	\$0.00	\$26.87
2026	\$10.34	\$0.00	\$26.87
2027	\$10.34	\$0.00	\$26.87
2028	\$10.34	\$0.00	\$26.87
2029	\$10.34	\$0.00	\$26.87
2030	\$10.34	\$0.00	\$26.87
2031	\$10.34	\$0.00	\$26.87
2032	\$10.34	\$0.00	\$26.87
2033	\$10.34	\$0.00	\$26.87
2034	\$10.34	\$0.00	\$26.87
2035	\$10.34	\$0.00	\$26.87
2036	\$10.34	\$0.00	\$26.87
2037	\$10.34	\$0.00	\$26.87
2038	\$10.34	\$0.00	\$26.87

Lastly, we rely on reports from the National Resource Council¹⁵ and the Minnesota Center for Environmental Advocacy¹⁶ for information on emissions damages costs per ton. This data is summarized below. These dollar value damages include harm to human health, crops, and the environment based on epidemiological and environmental studies.

¹⁵ National Research Council, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*. 2009.

¹⁶ MCEA, *Health & Environmental Costs of Electricity Generation in Minnesota*. 2013.

Table 11: Emissions Damage Rates (\$2014/ton)

Pollutant	Damage
CO2	\$5.22
SO2	\$5,049.25
NOX	\$1,392.90
PM-10	\$1,100.00
PM-2.5	\$18,500.00
Mercury	\$135,628,926.30

V. Results

A. DGSC AND REF IMPACT ON GENERATION AND CAPACITY MIX

1. Generation

Figure 5A shows the generation mix in Rhode Island under the baseline scenario. Rhode Island generation is dominated by natural gas-fired plants. Figure 5B shows the generation mix in Rhode Island under the 160 MW DGSC scenario. Solar and wind comprise a noticeably larger portion of generation under this scenario than in the baseline. Charts for the 200 and 1000 MW DGSC scenarios can be found in Appendix A. Generation is measured in MWh, the actual amount of electricity produced from the available capacity, which is measured in MW.

Figure 5A: Rhode Island Generation Mix (MWh) for Baseline Scenario

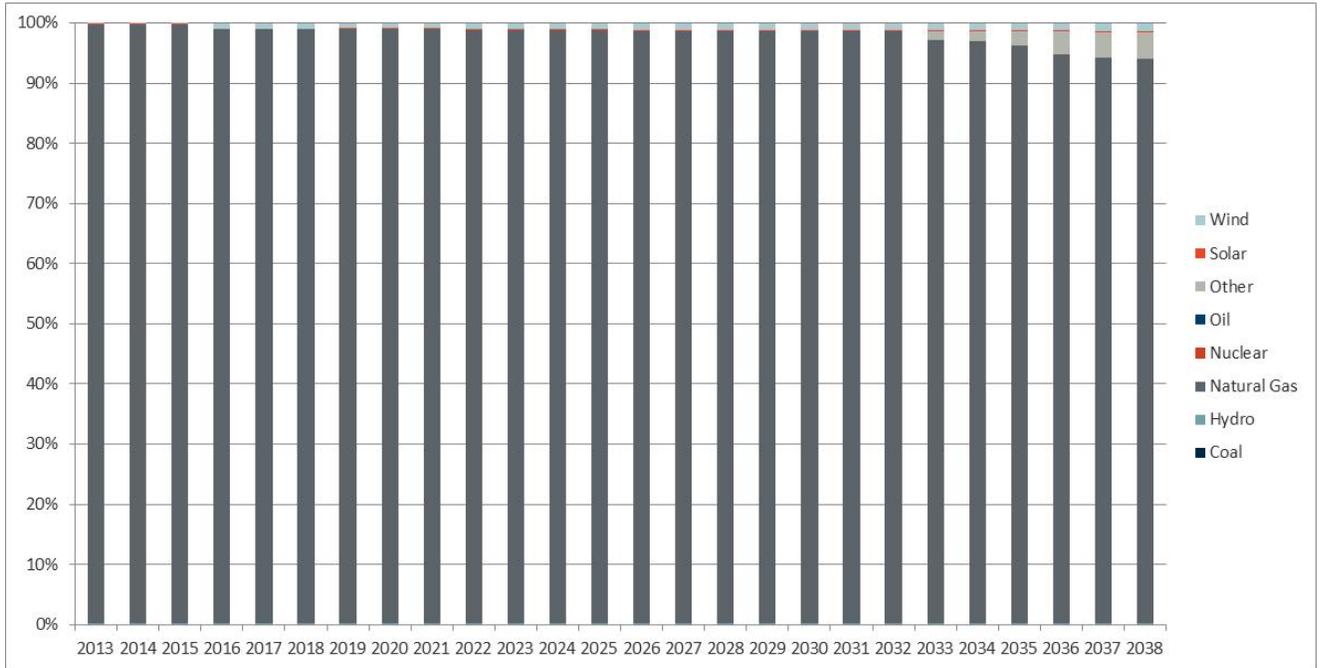


Figure 5B: Rhode Island Generation Mix (MWh) for 160 MW DGSC Scenario

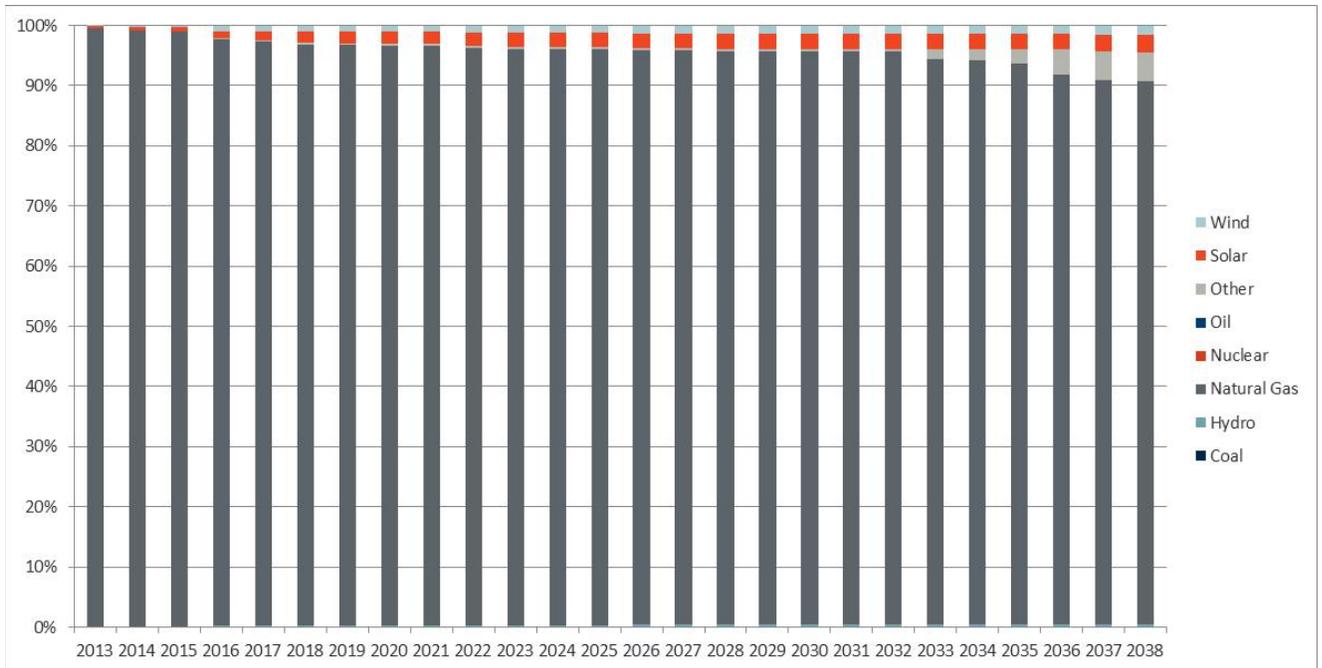


Figure 6A shows the generation mix in New England under the baseline scenario. Like Rhode Island, the New England generation mix is dominated by natural gas. Figure 6B shows the generation mix in New England under the 160 MW DGSC scenario. While this generation mix looks very similar to the baseline mix, it has a larger share of renewables. Charts for the 200 and 1000 MW DGSC scenarios can be found in Appendix A.

Figure 6A: New England Generation Mix (MWh) for Baseline Scenario

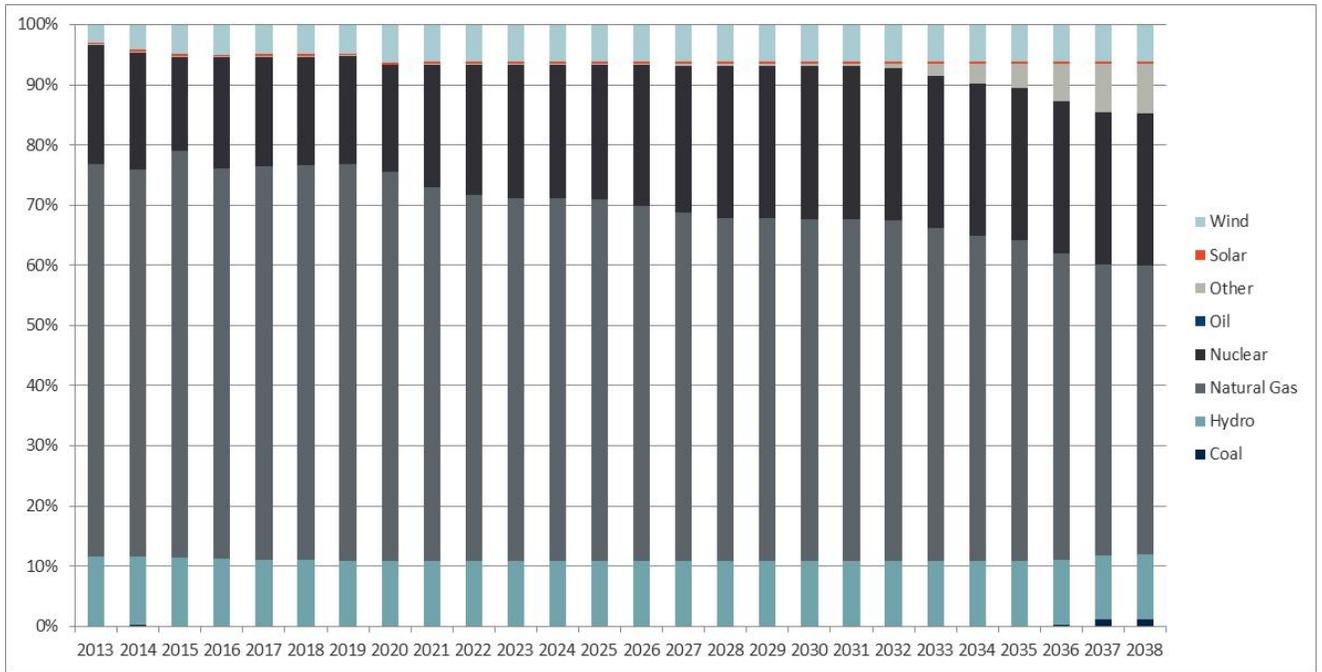
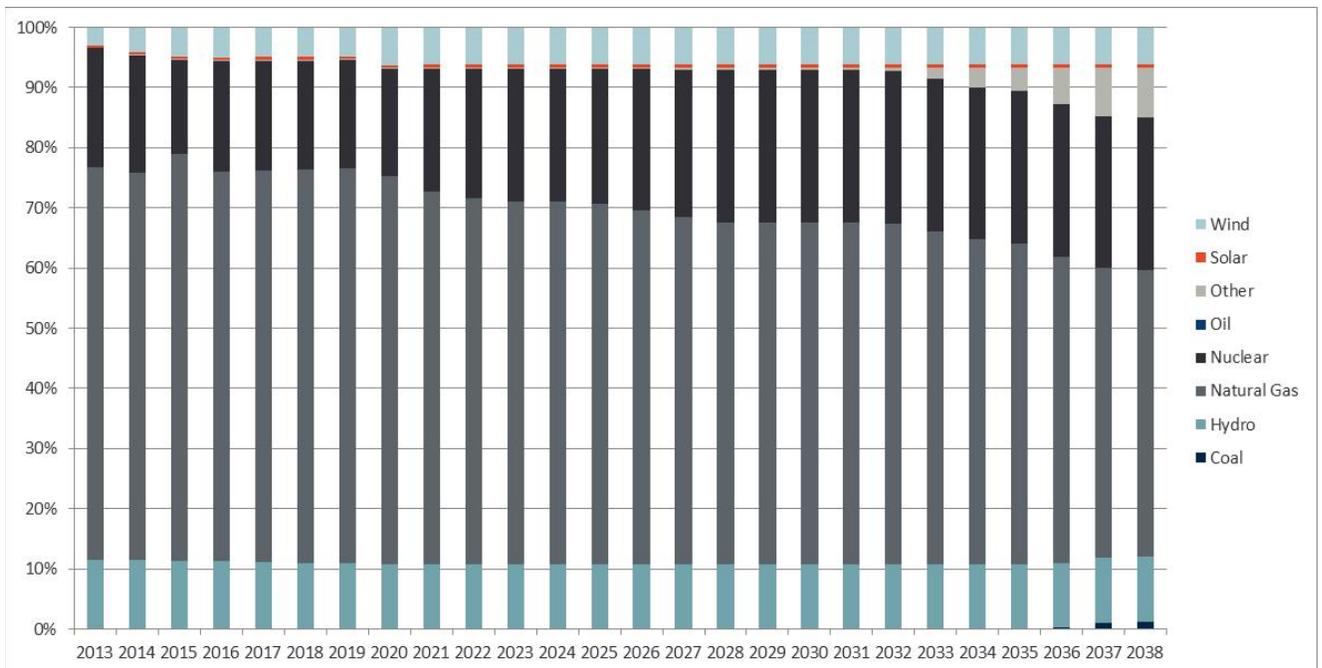


Figure 6B: New England Generation Mix (MWh) for 160 MW DGSC Scenario



2. Capacity

Figure 7A shows the capacity mix in Rhode Island under the baseline scenario. Figure 7B shows the capacity mix in Rhode Island under the 160 MW DGSC scenario. The increase in solar capacity is evident. Charts for the 200 and 1000 MW DGSC scenarios can be found in Appendix A.

Figure 7A: Rhode Island Capacity Mix (MW) for Baseline Scenario

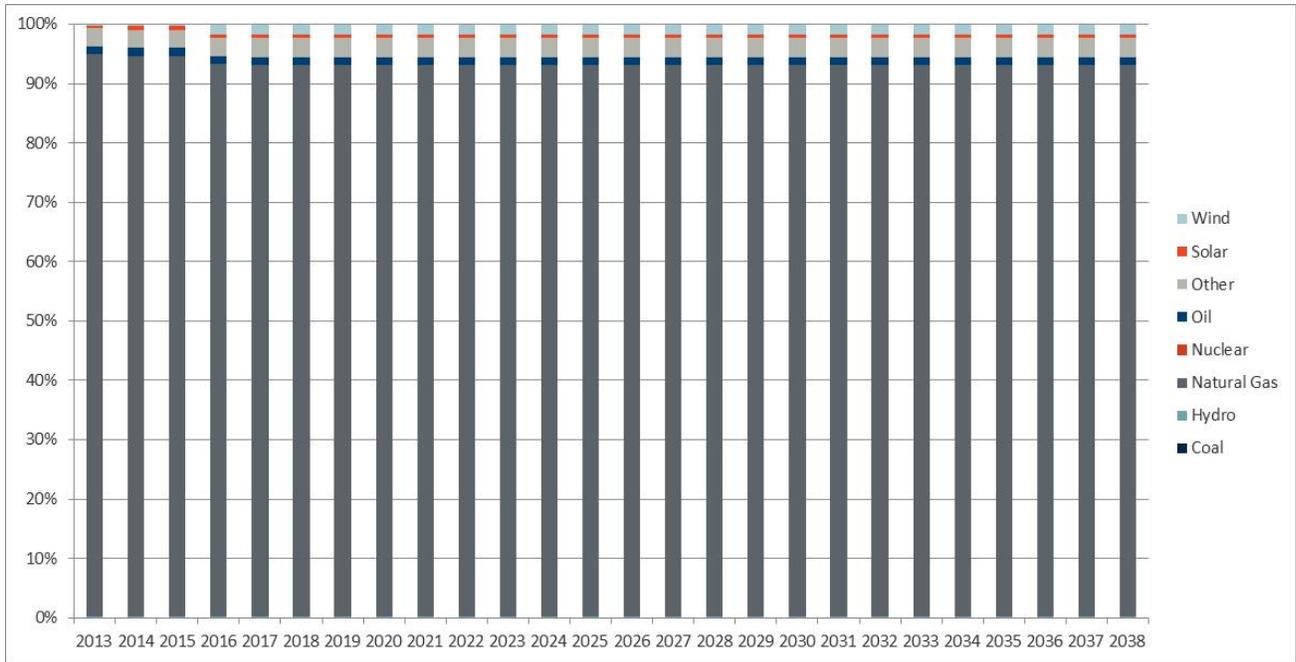


Figure 7B: Rhode Island Capacity Mix (MW) for 160 MW DGSC Scenario

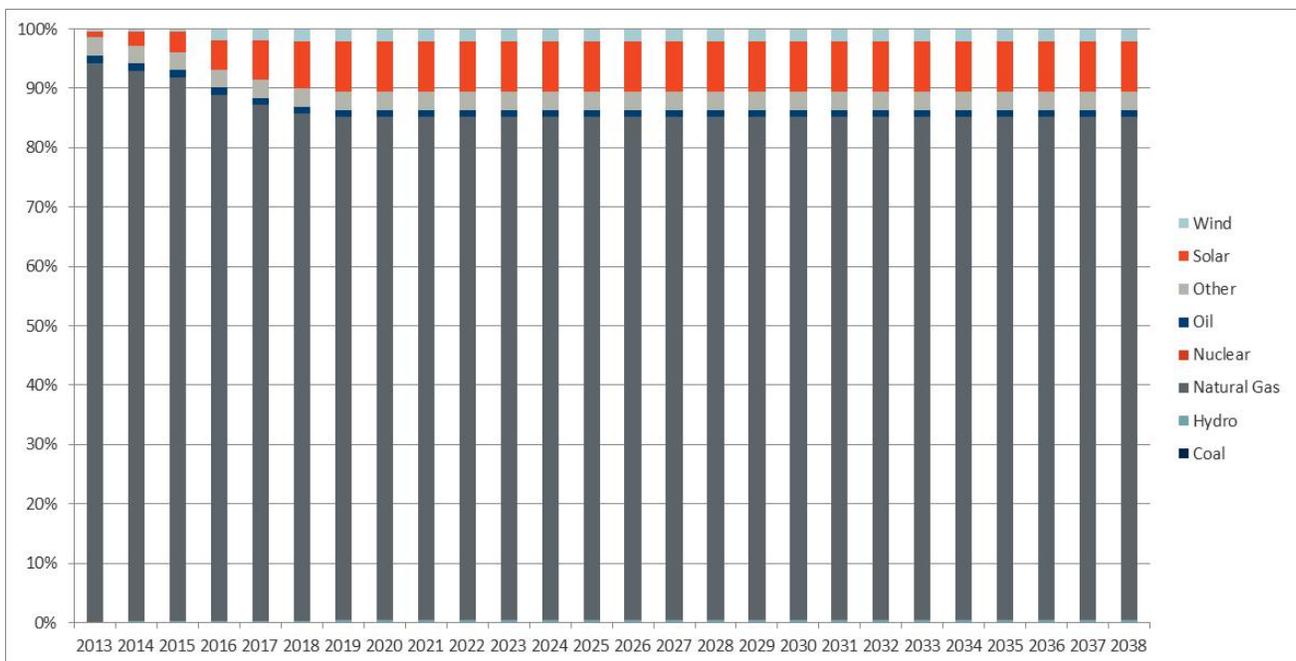


Figure 8A shows the capacity mix in New England under the baseline scenario. Figure 8B shows the capacity mix in New England under the 160 MW DGSC scenario. Charts for the 200 and 1000 MW DGSC scenarios can be found in Appendix A.

Figure 8A: New England Capacity Mix (MW) for Baseline Scenario

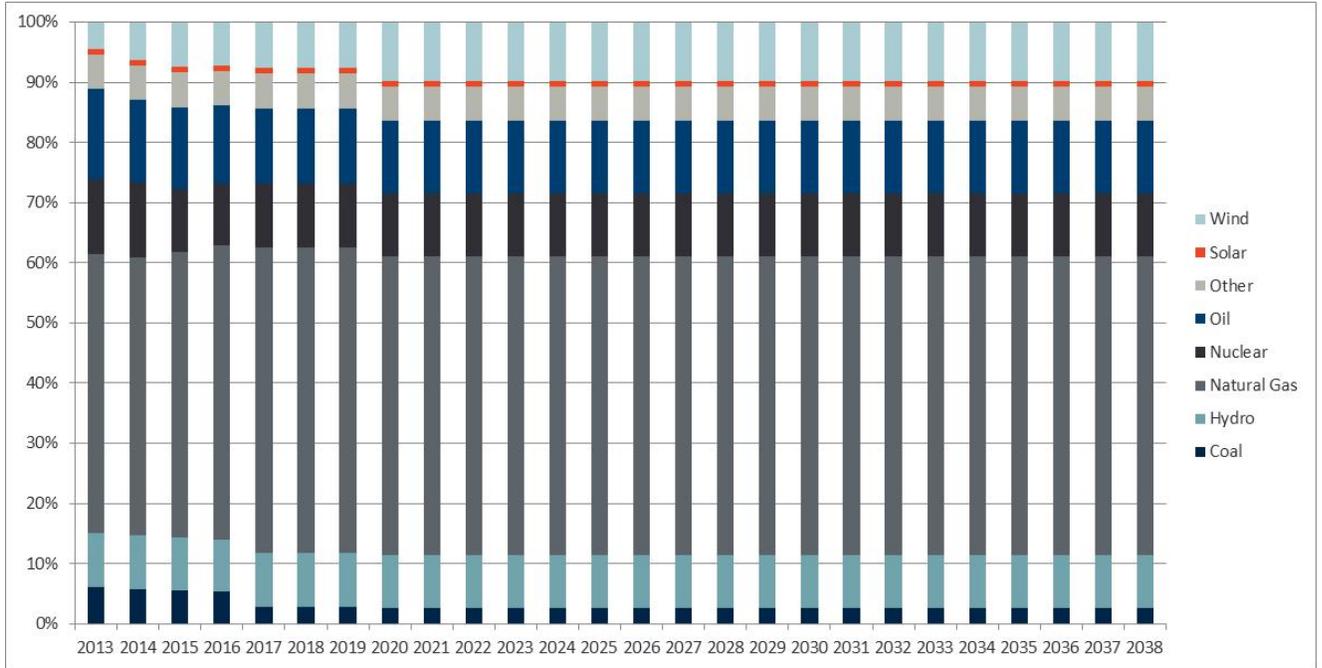
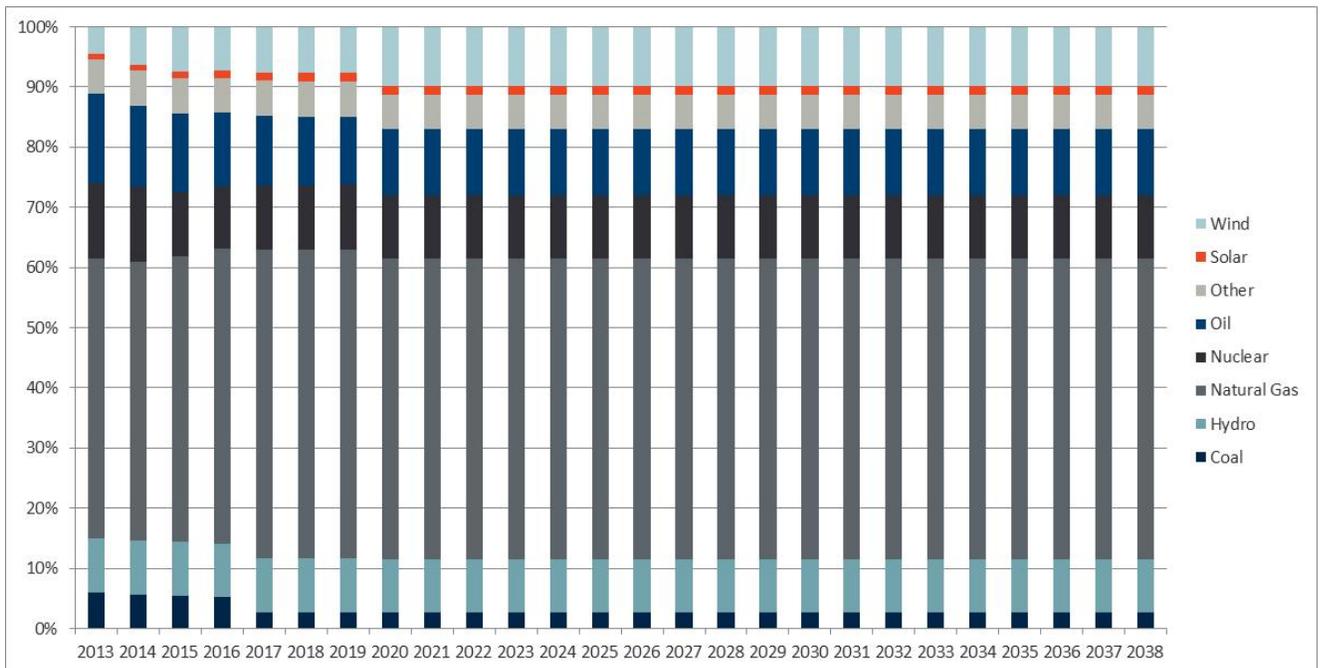


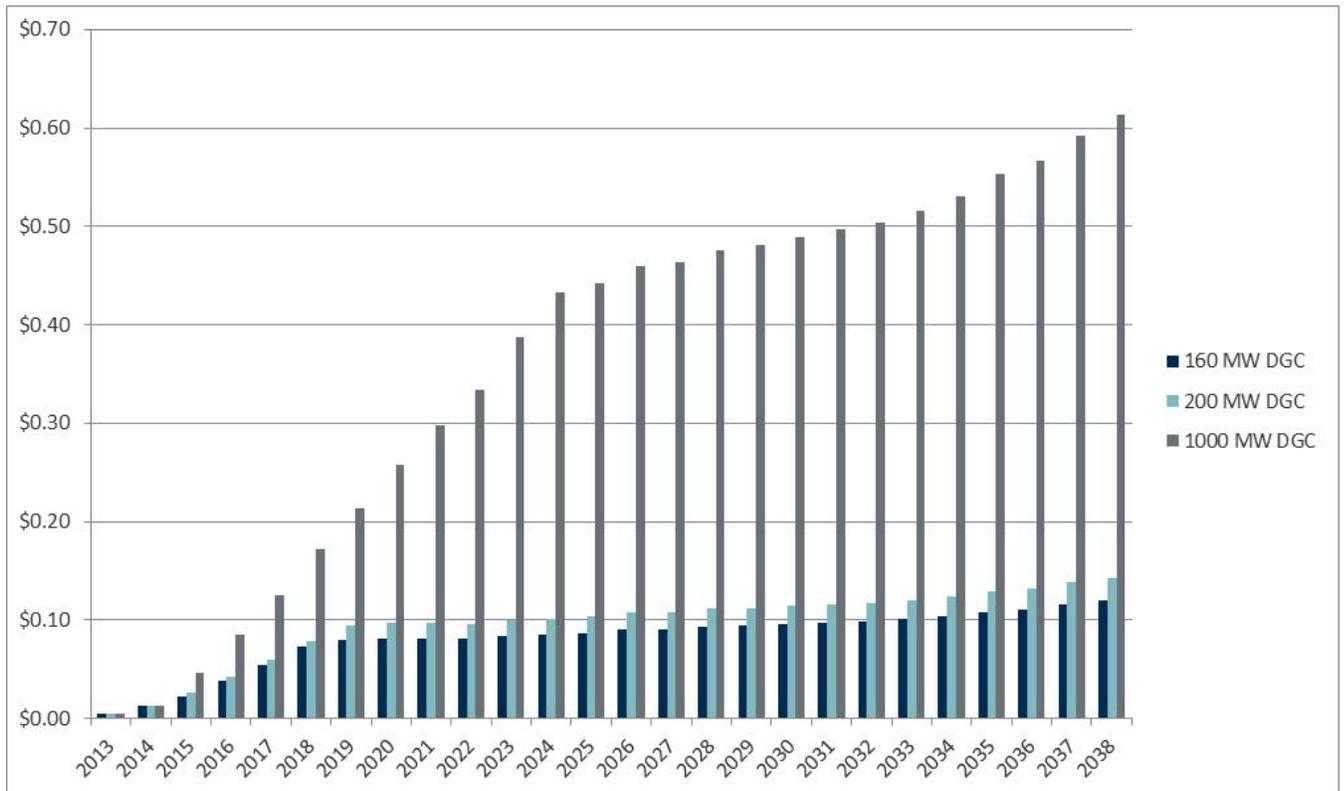
Figure 8B: New England Capacity Mix (MW) for 160 MW DGSC Scenario



B. DGSC AND REF IMPACT ON ELECTRICITY COSTS

Increased renewable capacity in Rhode Island can decrease New England wholesale electricity prices by replacing generation from high cost plants. The resulting price reduction is referred to as price suppression. We find that wholesale prices will be lower in the 160, 200, and 1000 MW DGSC scenarios than in the baseline scenario. Prices decrease by an average of \$0.08/MWh in the 160 MW DGSC scenario case. This figure is close to other estimates from National Grid and a 2013 Synapse report¹⁷. Price decreases get larger over time. As shown in Figure 9, price suppression grows from \$0.01/MWh in 2013 to \$0.12/MWh in 2038 under the 160 MW DGSC scenario¹⁸. Price suppression rises to as high as \$0.61/MWh in 2038 under the 1000 MW DGSC scenario. The magnitude of the price suppression will ultimately decline as the share of renewable capacity increases.

Figure 9: Rate Reductions from Price Suppression (\$2014/MWh)



¹⁷ Synapse, *Avoided Energy Supply Costs in New England: 2013 Report*. July 12, 2013.

¹⁸ This translates to an average of \$750,000 in savings from reduced rates for Rhode Island ratepayers annually

C. DGSC AND REF ECONOMIC IMPACTS

As discussed in Section III, economic impacts are measured using IMPLAN. This model determines economic output, employment, and state tax revenues accounting for changes in final demand that result from the DGSC and REF programs.

Figure 10 shows economic output impacts from the DGSC and REF programs. These numbers represent the annual change in economic output caused by the DGSC and REF programs. These impacts are smallest for the 160 MW DGSC scenario and largest for the 1000 MW DGSC scenario. Interestingly, economic output from the programs falls after 2016 when the federal solar ITC drops down to 10%. This makes solar more expensive for investors. The net present value of the economic output impacts for the 160 MW DGSC scenario is \$556 million. This figure, in part, reflects the program’s impact on in-state construction of renewable capacity and returns on investment to program participants (investors, businesses, municipalities, homeowners) and energy savings to ratepayers.

Figure 10: Economic Output Impacts (\$2014)

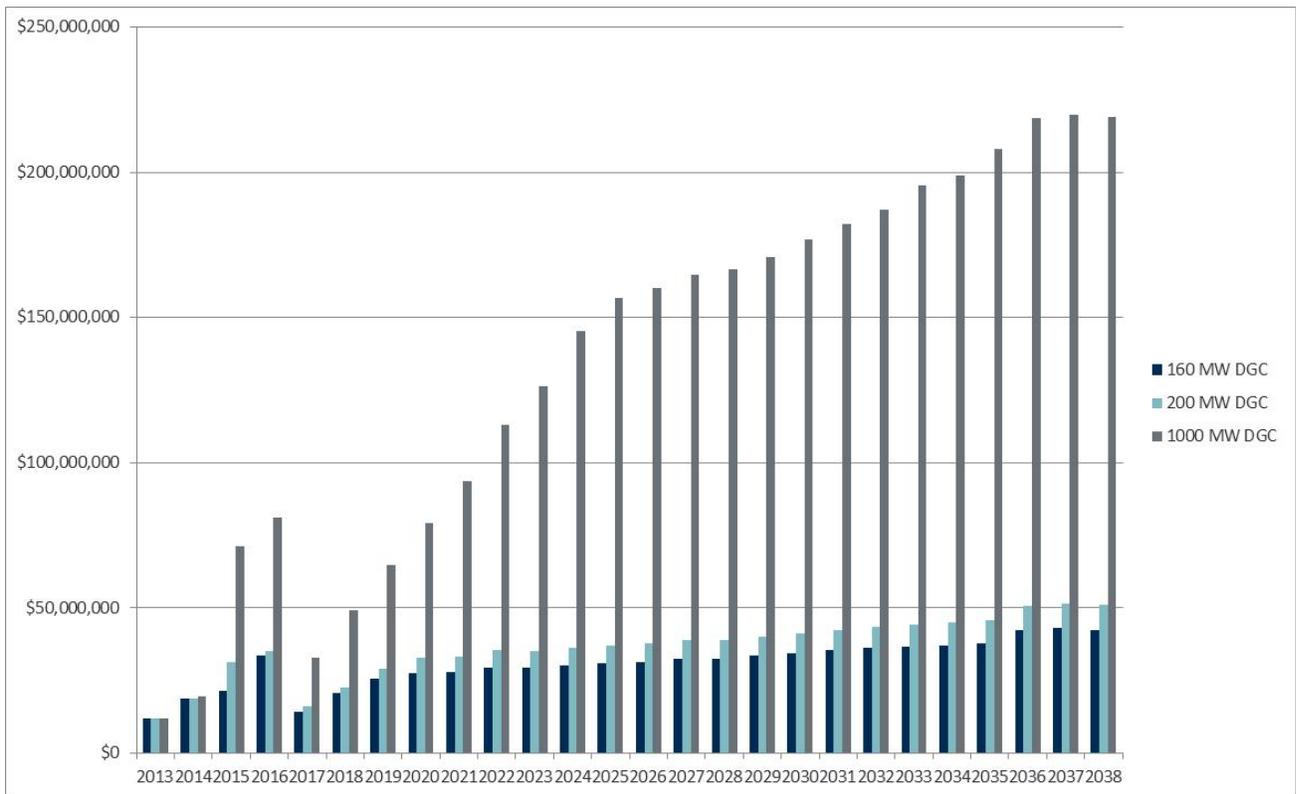


Figure 11 shows employment impacts from the DGSC and REF programs. These numbers represent the change in full-time employment caused by the DGSC and REF programs. These impacts largely mirror the output impacts. On average, 246 full-time equivalent jobs are created each year under the 160 MW DGSC scenario, 293 full-time equivalent jobs are created each year under the 200 MW DGSC scenario, and 1,095 full-time equivalent jobs are created each year under the 1000 MW DGSC scenario. These numbers include direct, indirect, and induced jobs.

Figure 11: Employment Impacts (Full-Time Jobs)

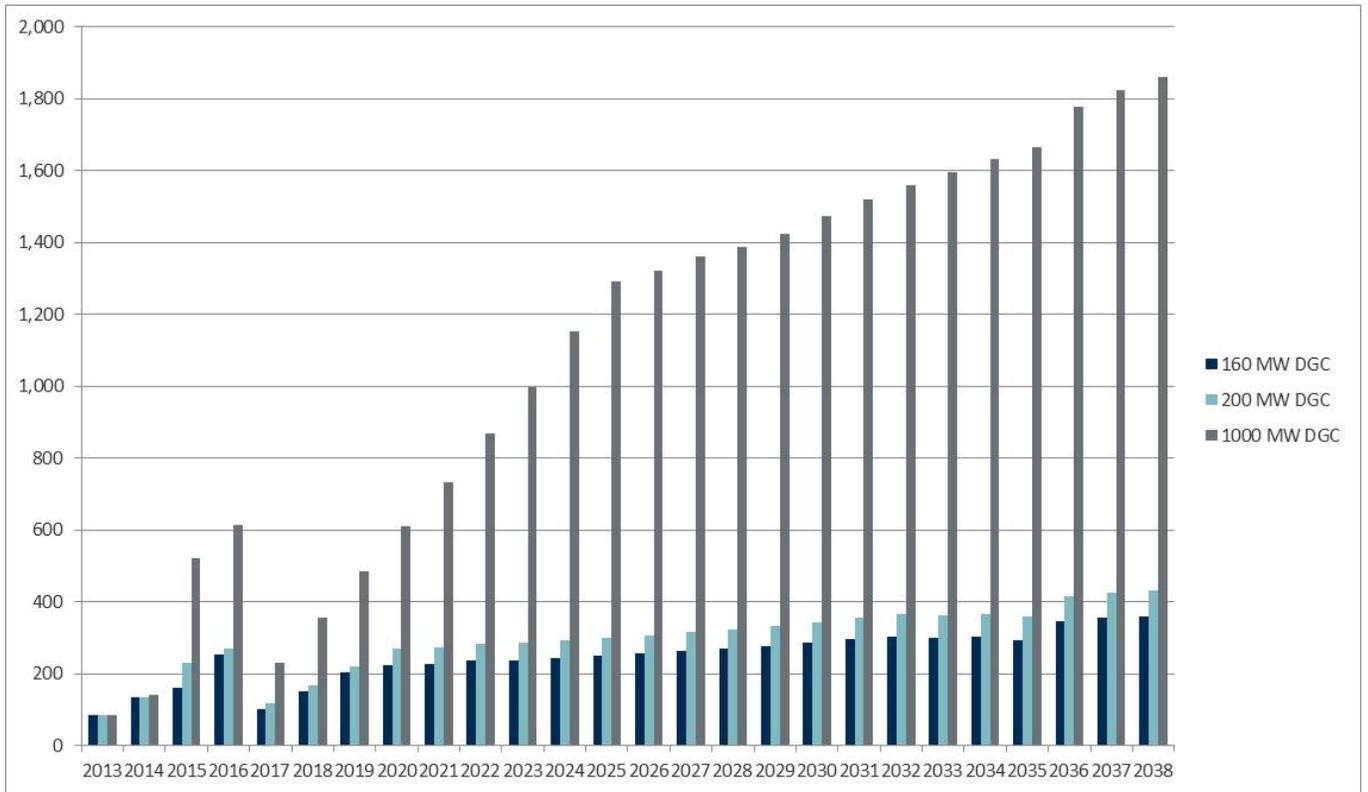
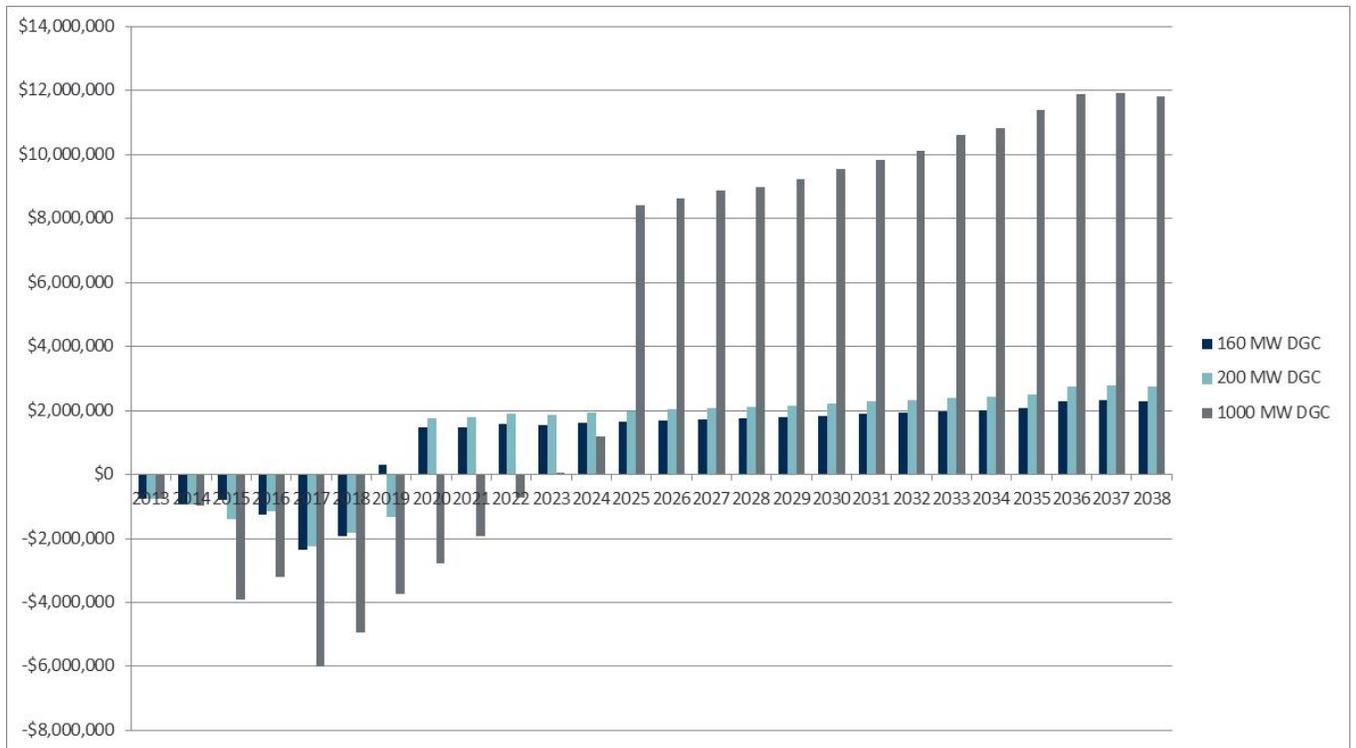


Figure 12 shows the state tax revenue impacts from the DGSC and REF programs. These impacts remain negative during the initial investment period. After construction is complete, however, the state begins to see net positive state tax impacts from investment returns and electricity savings. The net present value of state tax impacts is \$16 million under the 160 MW DGSC scenario, \$19 million under the 200 MW DGSC scenario, and \$63 million under the 1000 MW DGSC scenario.

Figure 12: State Tax Impacts (\$2014)



D. DGSC AND REF ENVIRONMENTAL IMPACTS

As discussed in Section III, environmental impacts are measured by determining the reduction in emissions of CO₂ and the criteria pollutants compared to the emission levels absent the DGSC and REF programs. We calculate the avoided cost of emissions allowances resulting from the programs by multiplying emissions reductions induced by the programs by emissions allowance costs shown in Table 10. These emissions reductions are then translated into dollar damages avoided reflecting the harm to human, health, and the environment avoided by the renewable capacity added under the programs.

1. Emissions

Figure 13 shows average annual CO₂ emissions reductions by scenario. Reductions are smallest for the 160 MW DGSC scenario and largest for the 1000 MW DGSC scenario. This is because less fossil fuel-fired generation is dispatched when more renewable capacity is added.

Figure 13: Average Annual CO₂ Emissions Reductions (Tons)

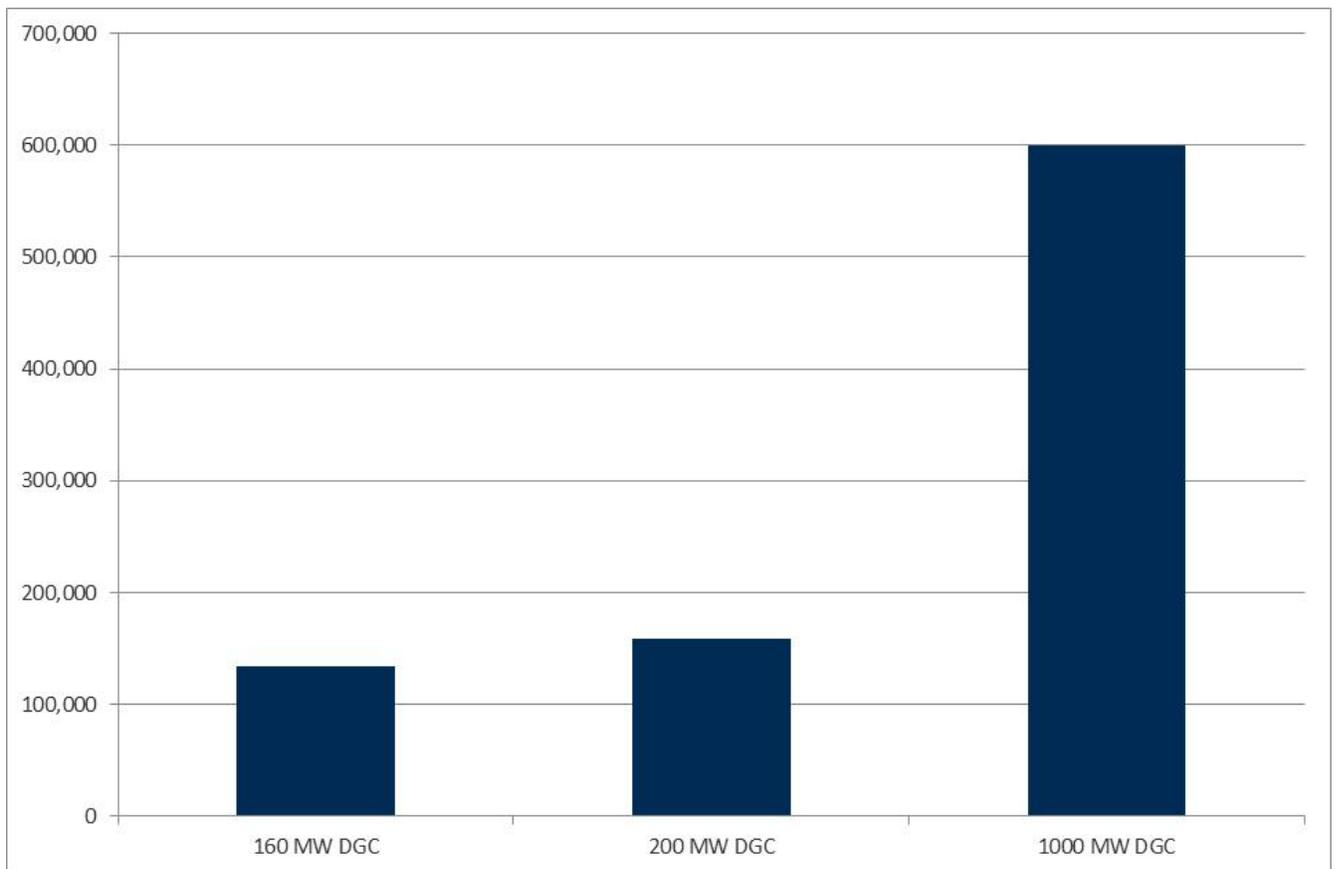
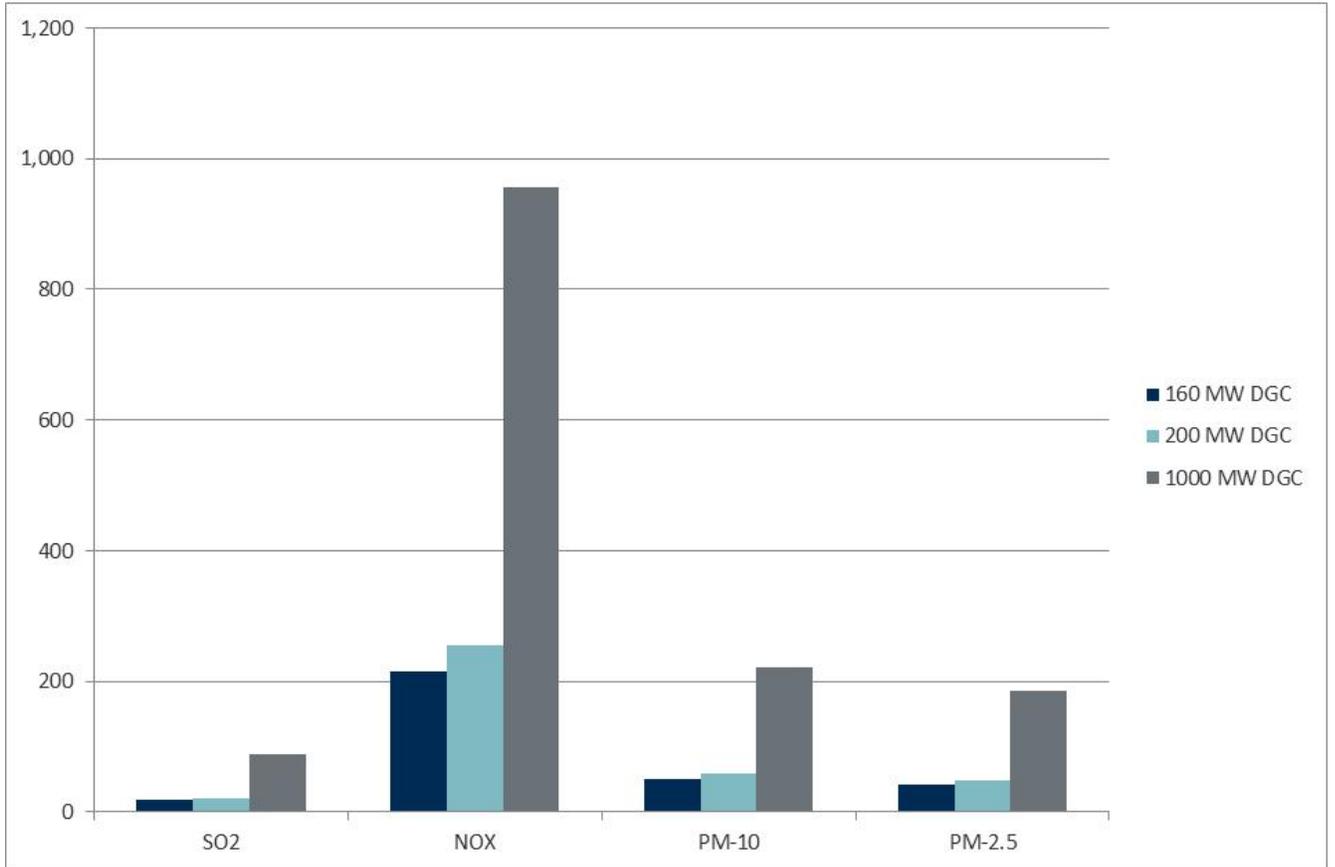


Figure 14 shows the average annual criteria pollutant emissions reductions by scenario. Again, reductions are smallest for the 160 MW DGSC scenario and largest for the 1000 MW DGSC scenario.

Figure 14: Average Annual Criteria Pollutant Emissions Reductions (Tons)



2. Allowance Costs

Figure 15 shows the net present value of CO2 emissions allowance cost reductions.

Figure 15: Net Present Value of CO2 Emissions Allowance Cost Reductions (\$2014)

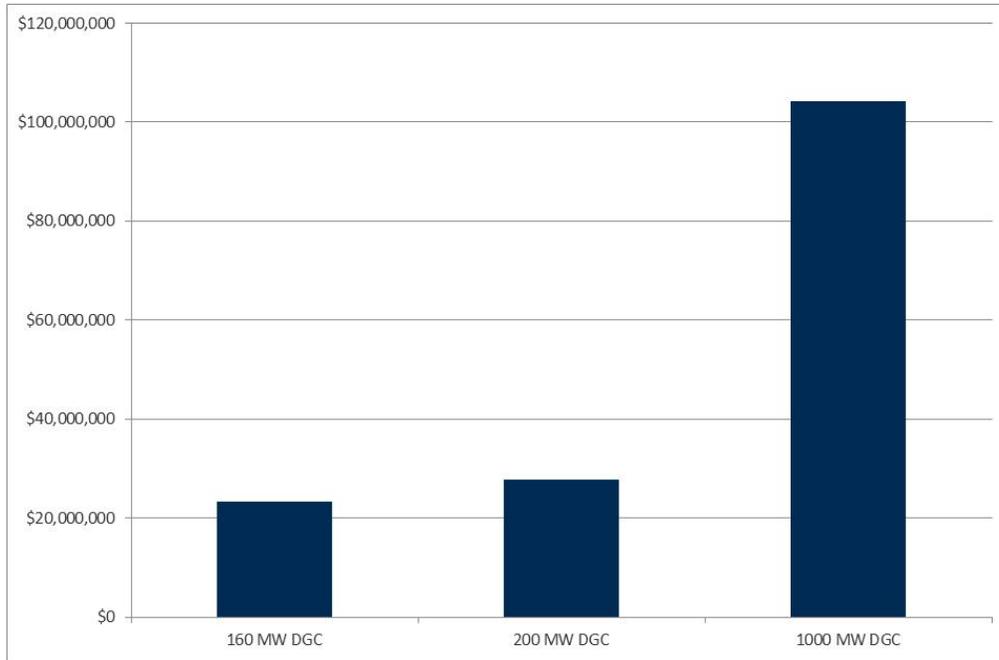
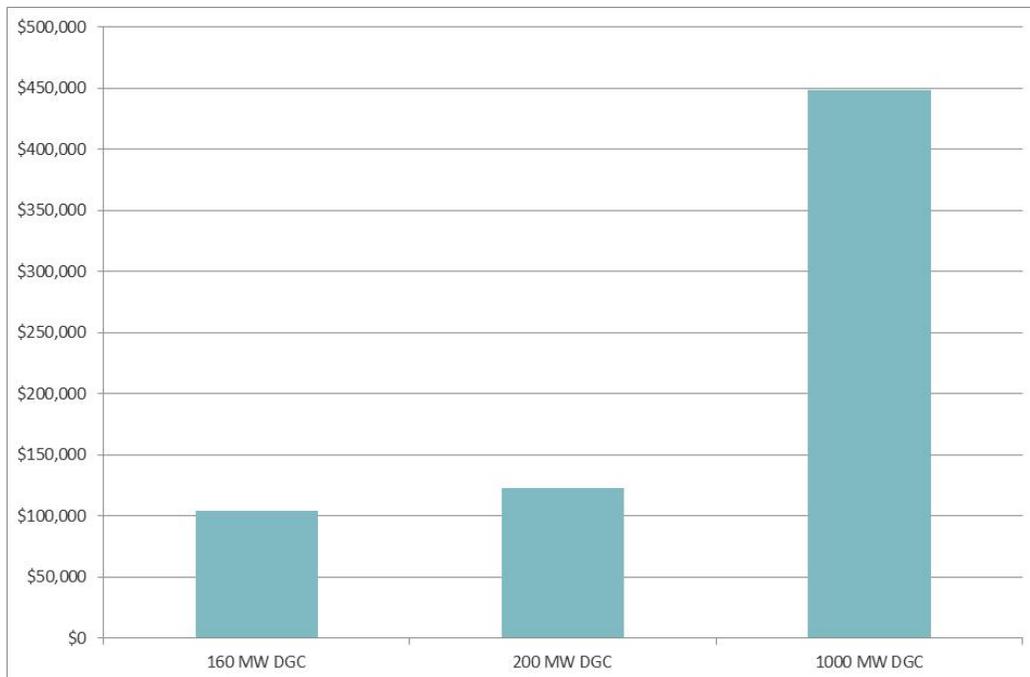


Figure 16 shows the net present value of NOX emissions allowance cost reductions.

Figure 16: Net Present Value of NOX Emissions Allowance Reductions (\$2014)



3. Damages Costs

Figure 17 shows the net present value of CO2 damage cost reductions.

Figure 17: Net Present Value of CO2 Damage Cost Reductions (\$2014)

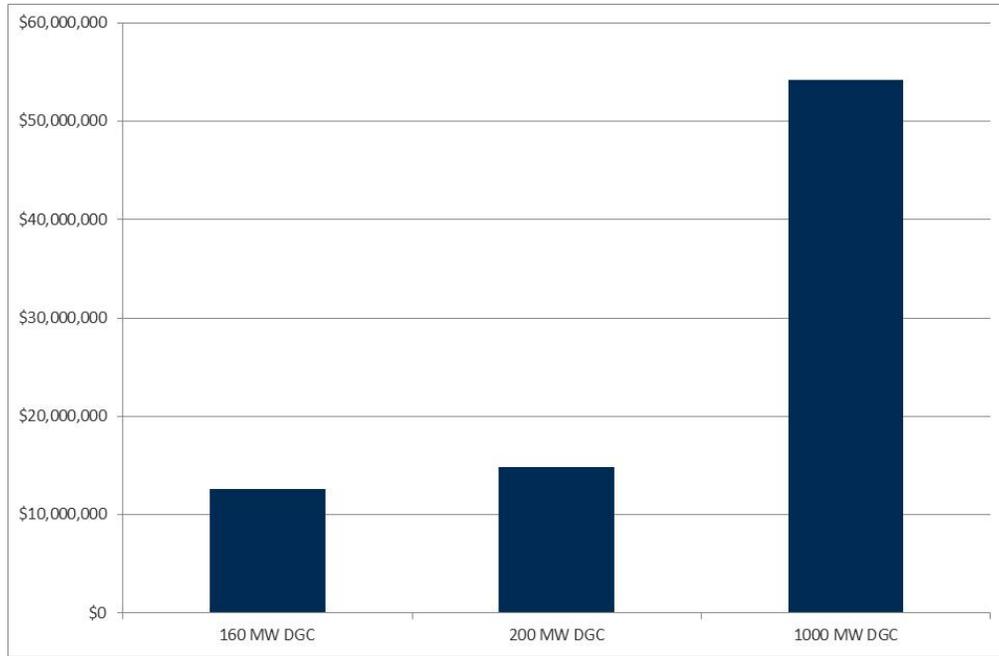
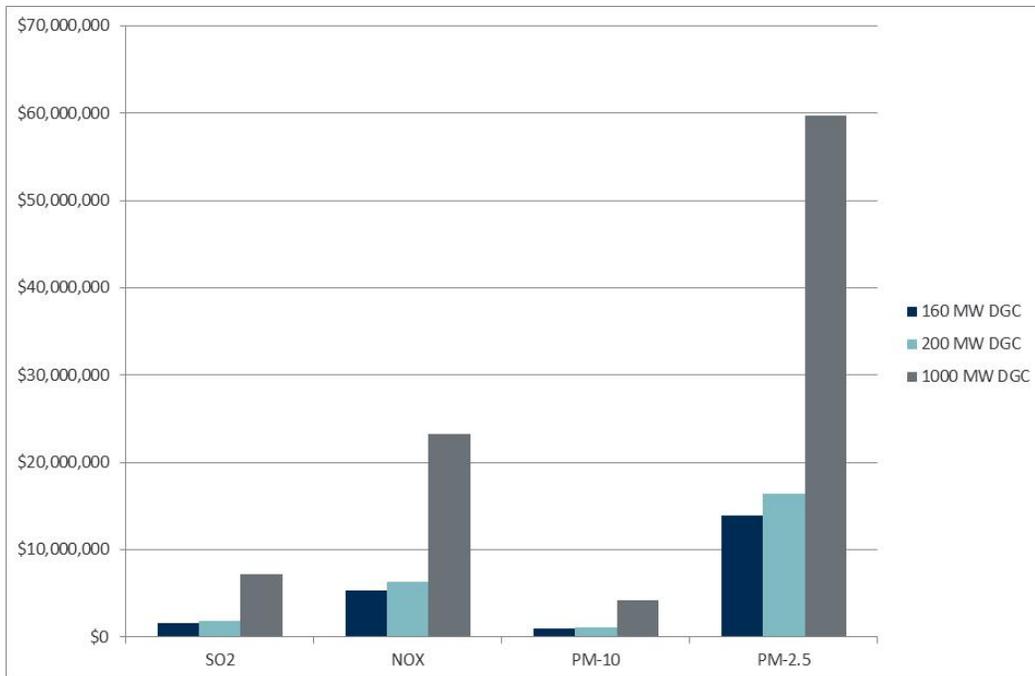


Figure 18 shows the net present value of criteria pollutant damage cost reductions.

Figure 18: Net Present Value of Criteria Pollutant Damage Cost Reductions (\$2014)



E. OTHER BENEFITS AND COSTS

The DGSC and REF induced renewable capacity may provide other benefits not directly captured by the price, environmental benefits described above. These include avoided transmission and distribution (T+D) costs, and reduced exposure to fuel price spikes (diversity) and reliability. There may also be some additional costs. These costs could include higher grid integration and management costs, which may partially offset the T+D and diversity benefits.

1. Diversity

Diversity savings capture the value of avoiding price increases by reliance on power plants reliant on highly volatile fuels. To measure this savings, we compared electric generating costs under the baseline and high gas price scenarios outlined in Figure 4. We estimated the NPV of these benefits to be \$5 million in \$2014.

2. Reliability

Although improved reliability is often cited as a benefit of increased reliance on renewable energy, this is difficult to measure in part because it is very site specific. The location of a renewable plant may help avoid a wide spread outage, but without a very detailed grid study, it is not easy to identify. Further, the modest addition of capacity added by the DGSC and REF programs makes it unlikely that they offer a large benefit. Consequently, no reliability value is attributed to the DCG and REF programs.

3. Avoided Costs of Transmission & Distribution

Transmission and Distribution (T+D) costs tend to be very site specific and therefore are difficult to estimate at the level of analysis presented here. The models employed did not simulate National Grid or ISO New England grid operations. National Grid recently reported to the Rhode Island Public Utility Commission that no T+D savings had occurred as result of the first 23.5 MW of renewable investments under the DGSC program.¹⁹ However, National Grid and the OER are currently running a pilot program that will provide better information regarding T&D delay or avoidance savings resulting from solar investment in Tiverton. A review of other studies indicates that these savings could be substantial. For example, a national review by the National Renewable Energy Laboratory (NREL) found that these savings ranged from \$4.28 to \$26.26/MWh. The “most common” was \$4.84/MWh. A 2013 Vermont study reported T&D savings of \$13.71/kw-month, but acknowledged that while this figure represented savings to Vermont ratepayers, it would result in costs to others served by the New England ISO.²⁰

¹⁹ National Grid response to Records Request by the RI Public Utility Commission February 26, 2014, on March 11, 2014. (letter from T. Teehan to L. Massaro, Commission Clerk)

²⁰ Vermont Public Service Department, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012*. January 25, 2013.

4. Grid Integration Costs

In addition to the savings that may be attributable to adding renewable energy capacity to the grid, there are costs. The same NREL study cited above, found that integration costs associated with renewable energy because of the lack of centralized control and weather and time of day variations were not trivial. NREL reported that these costs for solar PV ranged between \$2.50 and \$10.90/MWh.

VI. Conclusions

This analysis indicates that DGSC and REF will result in net positive economic and environmental impacts over the period 2014-2038. These impacts are relative to a scenario without DGSC and REF programs and incorporate both the positive and negative impacts of the DGSC and REF programs. All of these positive impacts are net of increased costs to ratepayers and net of investments that would have taken place in the absence of the DGSC and REF programs. The environmental impacts are also net of emissions of CO₂ and criteria pollutants that would have occurred in the absence of the programs. All three scenarios considered, which add between 164 MW and 1008 MW of renewable energy capacity to Rhode Island between 2015 and 2024 (including REF capacity), yielded net positive economic and environmental impacts. Economic output will increase between \$556 and \$2,340 million in present value terms. The average number of jobs created will be between 246 and 1,095 (these are not additive over time). These positive impacts are net of increased costs to ratepayers and net of investments that would have taken place in the absence of the DGSC and REF program. The environmental impacts are also net of emission of carbon dioxide and criteria pollutant emission that would occur in the absence of the program.

Carbon dioxide emissions will be reduced creating a social benefit of between \$13 million and \$54 million on a NPV basis. Reductions in criteria pollutants can also be attributed to the program. The combined damages avoided by reducing SO₂, NO_X, PM-10, and PM-2.5 emissions ranges between \$22 million and \$94 million on a NPV basis. Since these reductions are mostly from the reduced generation of power plants located outside of Rhode Island, not all of the benefits will be captured by Rhode Island residents. Tracing the actual exposure paths and associated damages from pollution from these plants to determine precisely who benefits, however, is beyond the scope of this study. Some pollution emissions are most harmful in close proximity to the source, other emissions do more harm downwind.

Table 12A: Average Annual Impacts of DGSC and REF Programs

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Economic Output (\$2014 MM)	\$30.65	\$36.40	\$135.13
Employment (FTE Jobs)	246	293	1,095
State Tax Impacts (\$2014 MM)	\$1.05	\$1.24	\$4.40
CO2 Damage Cost Reductions (\$2014 MM)	\$0.70	\$0.83	\$3.13
SO2 Damage Cost Reductions (\$2014 MM)	\$0.09	\$0.11	\$0.45
NOX Damage Cost Reductions (\$2014 MM)	\$0.30	\$0.35	\$1.33
PM-10 Damage Cost Reductions (\$2014 MM)	\$0.05	\$0.06	\$0.24
PM-2.5 Damage Cost Reductions (\$2014 MM)	\$0.77	\$0.91	\$3.42

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.

Table 12B: Net Present Value Impacts of DGSC and REF Programs (\$2014 MM)

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Economic Output	\$556	\$658	\$2,340
State Tax Impacts	\$16	\$19	\$63
CO2 Damage Cost Reductions	\$13	\$15	\$54
SO2 Damage Cost Reductions	\$2	\$2	\$7
NOX Damage Cost Reductions	\$5	\$6	\$23
PM-10 Damage Cost Reductions	\$1	\$1	\$4
PM-2.5 Damage Cost Reductions	\$14	\$16	\$60

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.

Table 13A: Average Annual Ratepayer Impacts of DGSC and REF Programs (\$2014 MM)

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Ratepayer Price Suppression Savings	\$0.75	\$0.90	\$3.44
Ratepayer Program Costs	-\$17.93	-\$20.94	-\$136.83
Net Ratepayer Impacts	-\$17.18	-\$20.04	-\$133.39

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.

Table 13B: Net Present Value Ratepayer Impacts of DGSC and REF Programs (\$2014 MM)

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Ratepayer Price Suppression Savings	\$13	\$16	\$59
Ratepayer Program Costs	-\$367	-\$427	-\$2,680
Net Ratepayer Impacts	-\$354	-\$412	-\$2,621

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.

Rhode Island ratepayers will bear the cost of these programs through rate increases to: 1) cover the costs to National Grid for contracting above market rate contracts and or tariffs and contracting administration and 2) a fee to fund the REF. These costs, however, are partially offset over the study period by rate reductions that result from increased reliance on renewable energy capacity, which exhibit lower operating costs.

It is important to recognize that the results presented here are sensitive to several key assumptions. First, the study reflects the assumption that solar energy costs will continue to fall over time at 1.5% per year. A more rapid decline will increase the savings attributable to the programs, but also raise questions regarding the need for state level incentives. Second, the study accounts for natural gas price increases deemed most likely over the 25 year study period. The diversity value of \$5 million in net present value terms would be considerable higher if an even higher gas price scenario was considered. Third, the study does not reflect the completion of the Deepwater federal offshore wind project.. The final size of this project and the destination of power generated are too uncertain to account for at this time.

Finally, adding renewable capacity may provide additional benefits including T+D savings and protection against natural gas price spikes, which the state and New England have experienced in recent years. At the same time, these additions may also result in higher grid management costs. More definitive calculations of these benefits is beyond the scope of this report.

VII. Appendix A: Generation and Capacity Mixes for 200 and 1000 MW DGSC Scenarios

A. GENERATION

Figure A1 shows the generation mix in Rhode Island under the 200 MW DGSC scenario. Figure A2 shows the generation mix in Rhode Island under the 1000 MW DGSC scenario.

Figure A1: Rhode Island Generation Mix (MWh) for 200 MW DGSC Scenario

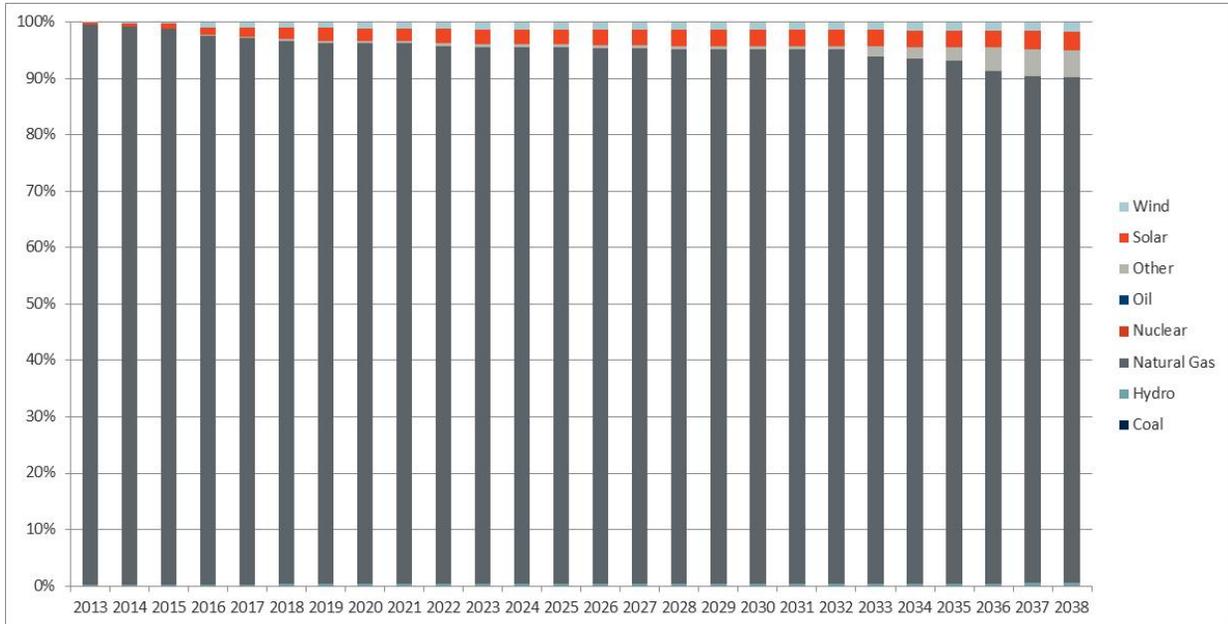


Figure A2: Rhode Island Generation Mix (MWh) for 1000 MW DGSC Scenario

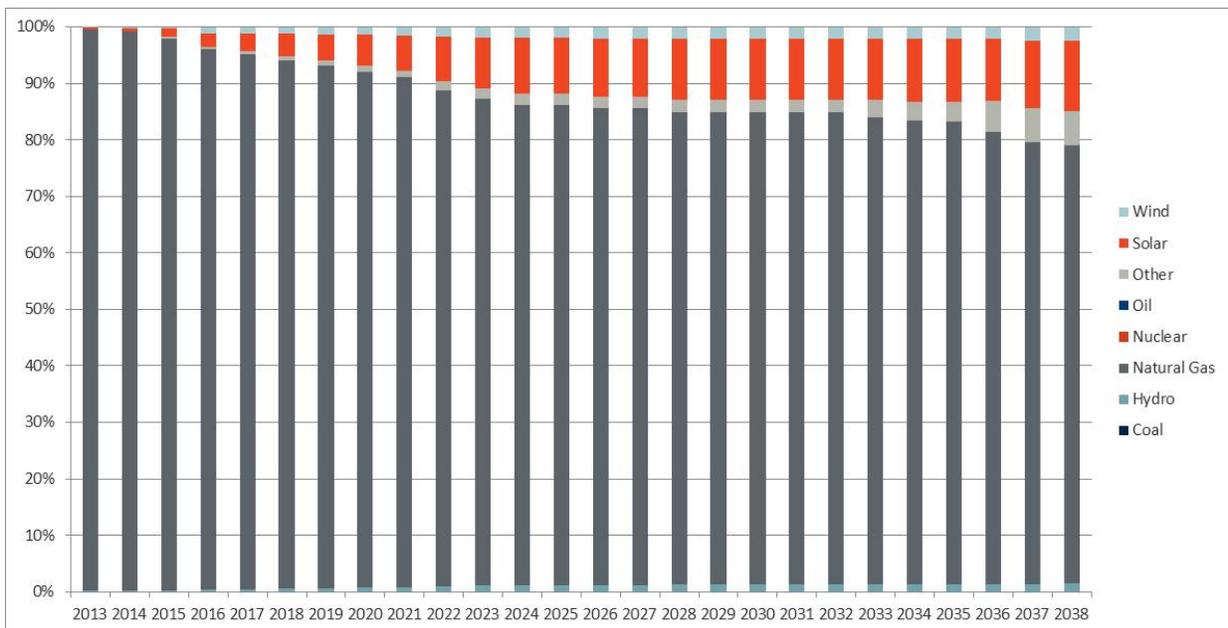


Figure A3 shows the generation mix in New England under the 200 MW DGSC scenario. Figure A4 shows the generation mix in New England under the 1000 MW DGSC scenario.

Figure A3: New England Generation Mix (MWh) for 200 MW DGSC Scenario

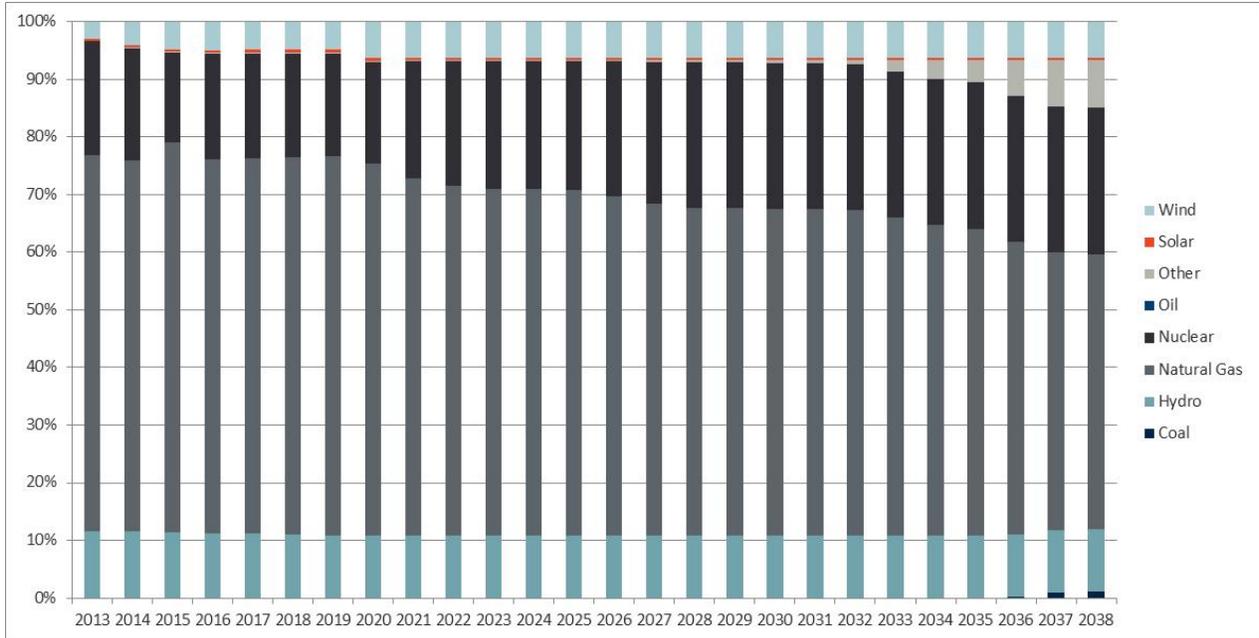
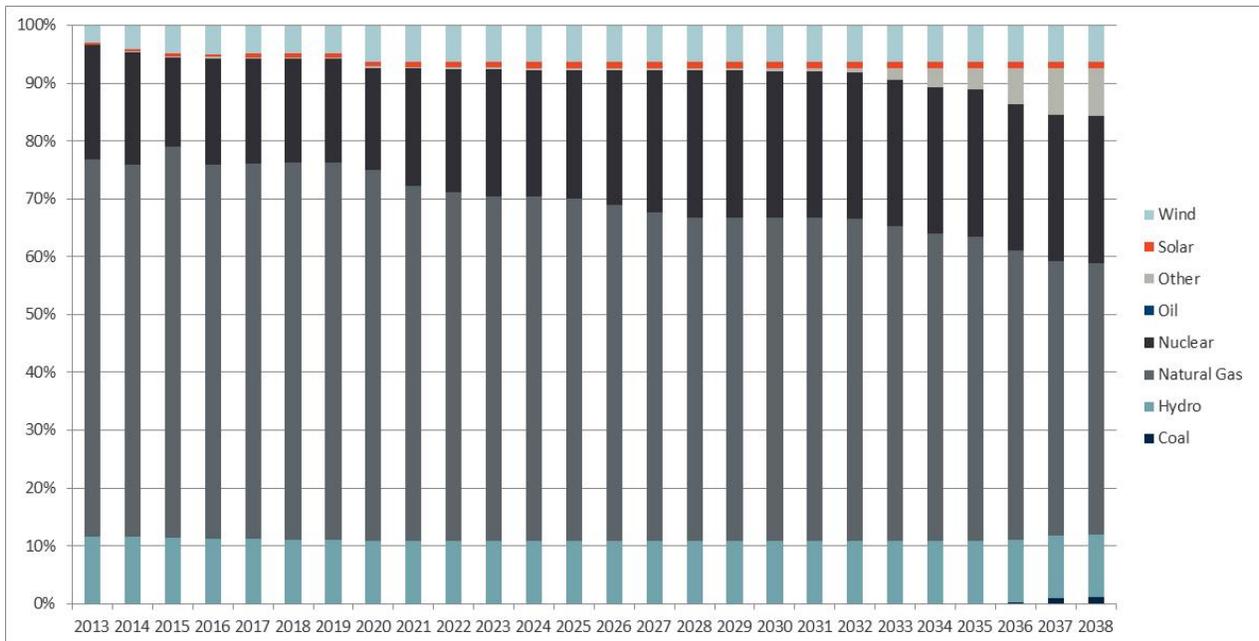


Figure A4: New England Generation Mix (MWh) for 1000 MW DGSC Scenario



B. CAPACITY

Figure A5 shows the capacity mix in Rhode Island under the 200 MW DGSC scenario. Figure A6 shows the capacity mix in Rhode Island under the 1000 MW DGSC scenario.

Figure A5: Rhode Island Capacity Mix (MW) for 200 MW DGSC Scenario

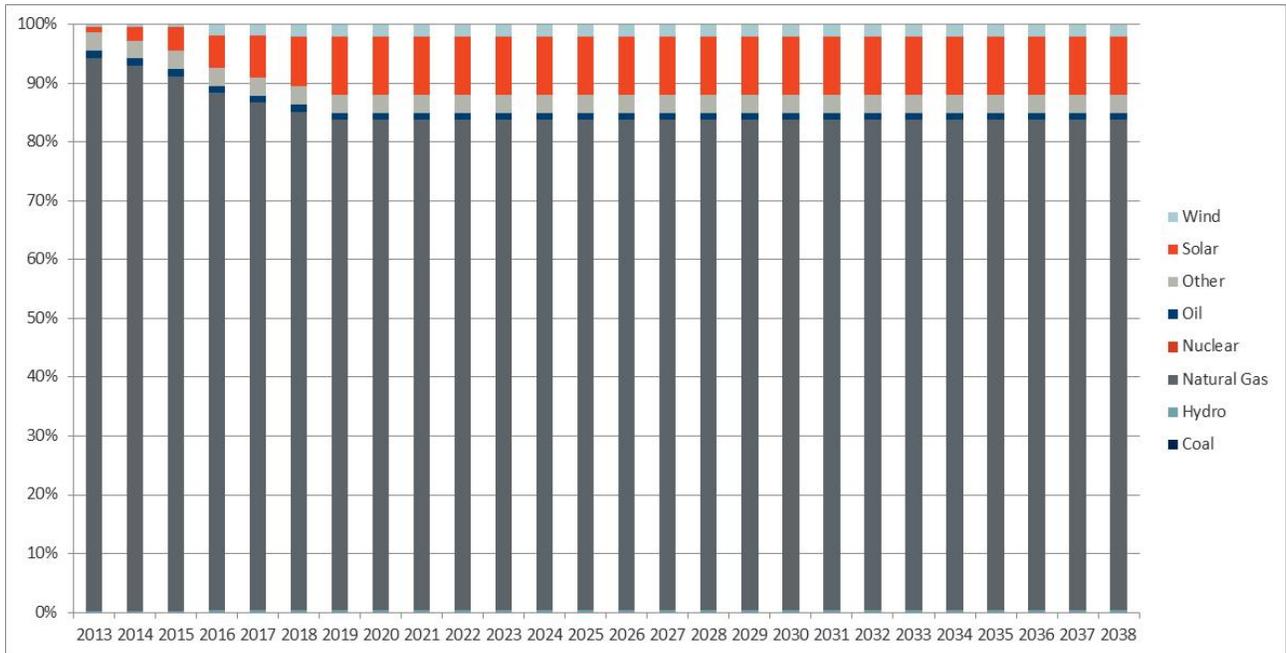


Figure A6: Rhode Island Capacity Mix (MW) for 1000 MW DGSC Scenario

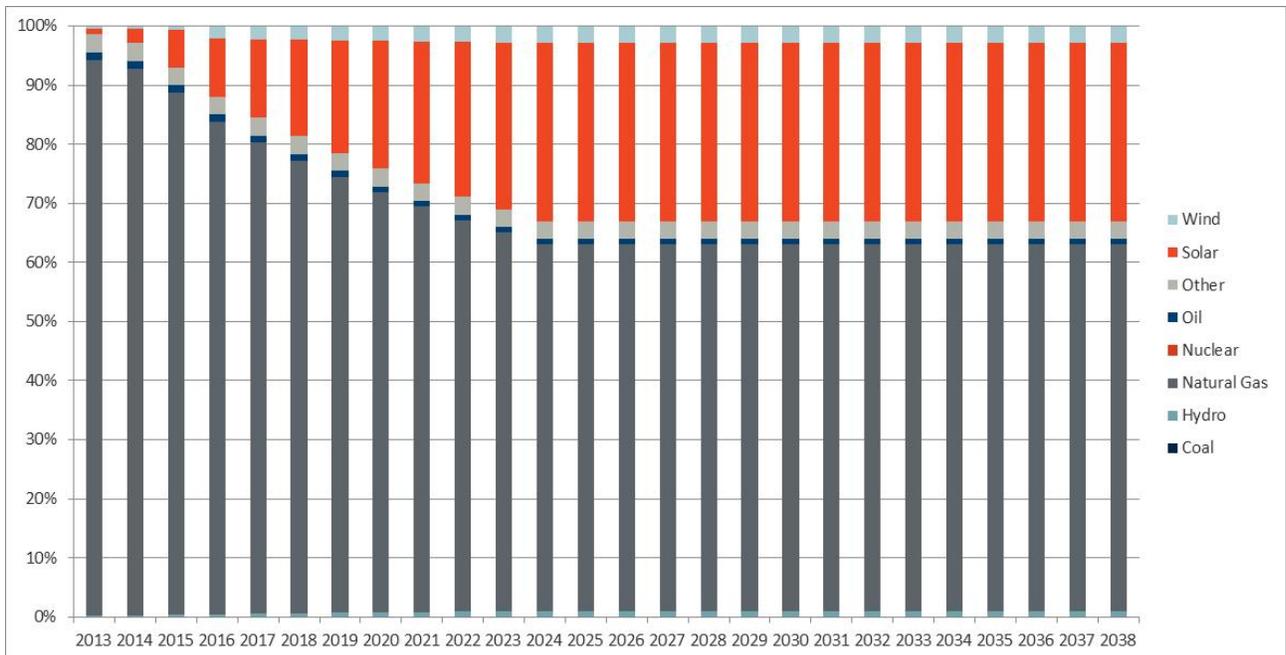


Figure A7 shows the capacity mix in New England under the 200 MW DGSC scenario. Figure A8 shows the capacity mix in New England under the 1000 MW DGSC scenario.

Figure A7: New England Capacity Mix (MW) for 200 MW DGSC Scenario

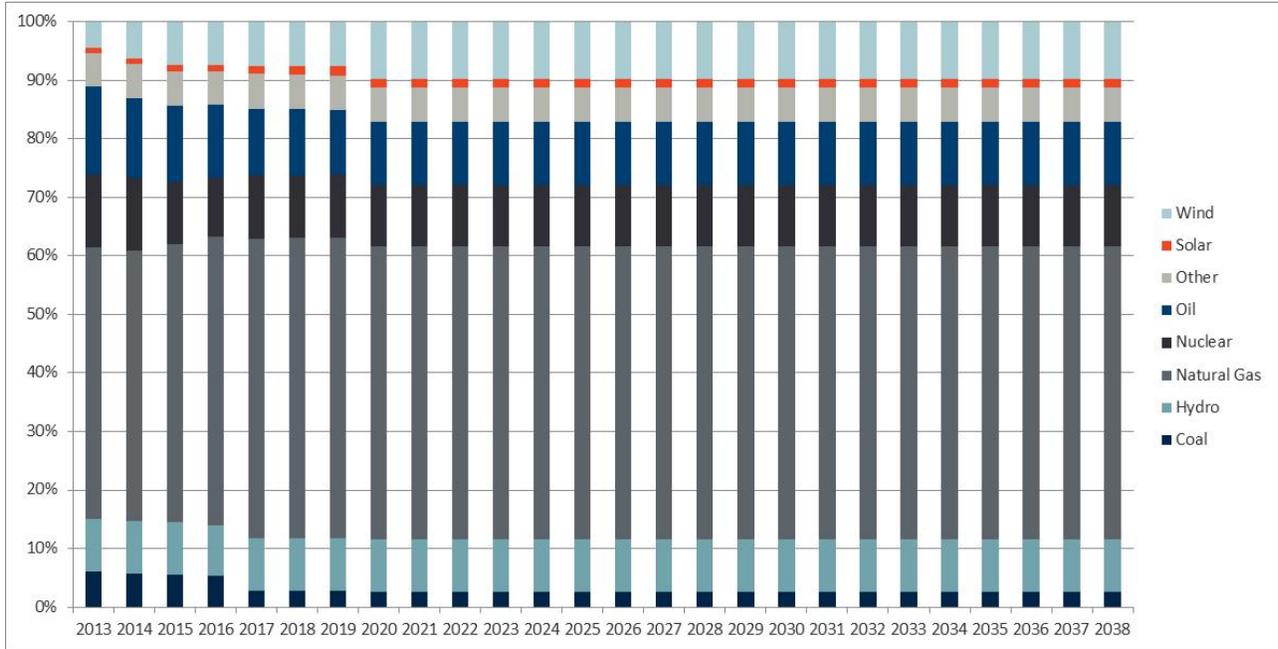
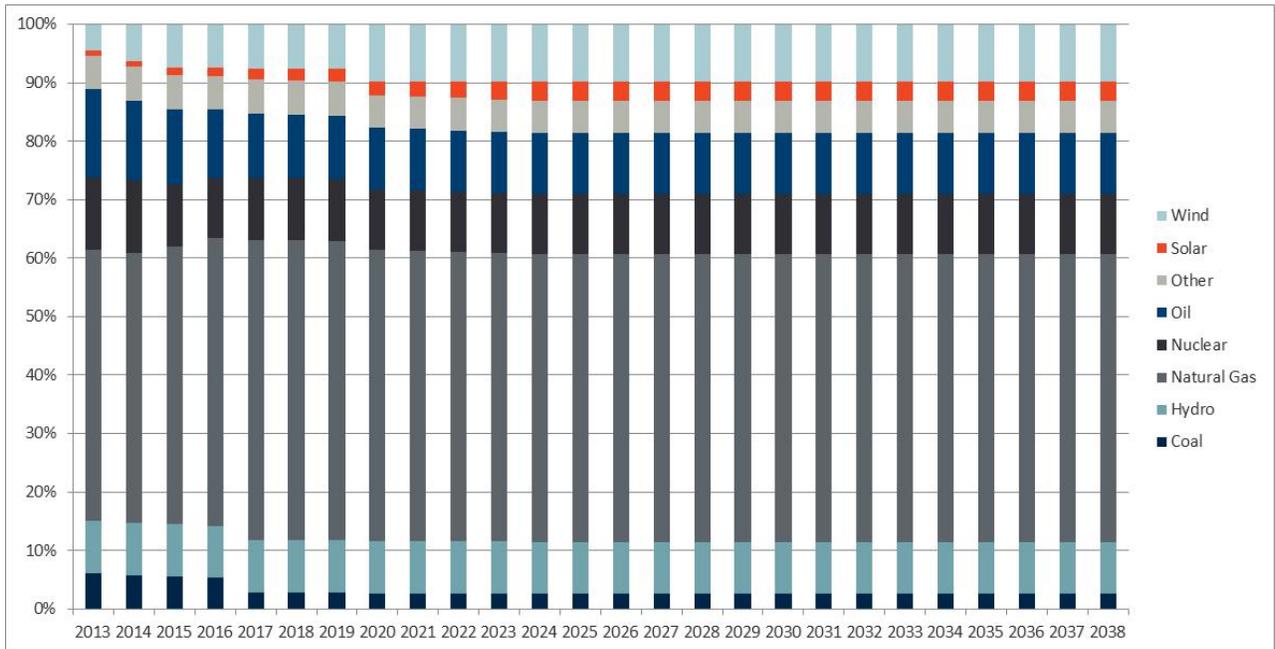


Figure A8: New England Capacity Mix (MW) for 1000 MW DGSC Scenario



VIII. Appendix B: Annual Environmental Results

A. EMISSIONS

Figure B1 shows CO₂ emissions changes by year from the DGSC and REF programs. Figure B2 shows SO₂ emissions changes by year from the DGSC and REF programs. Figure B3 shows NO_x emissions changes by year from the DGSC and REF programs. Figure B4 shows PM-10 emissions changes by year from the DGSC and REF programs. Figure B5 shows PM-2.5 emissions changes by year from the DGSC and REF programs.

Figure B1: CO₂ Emissions Changes (Tons)

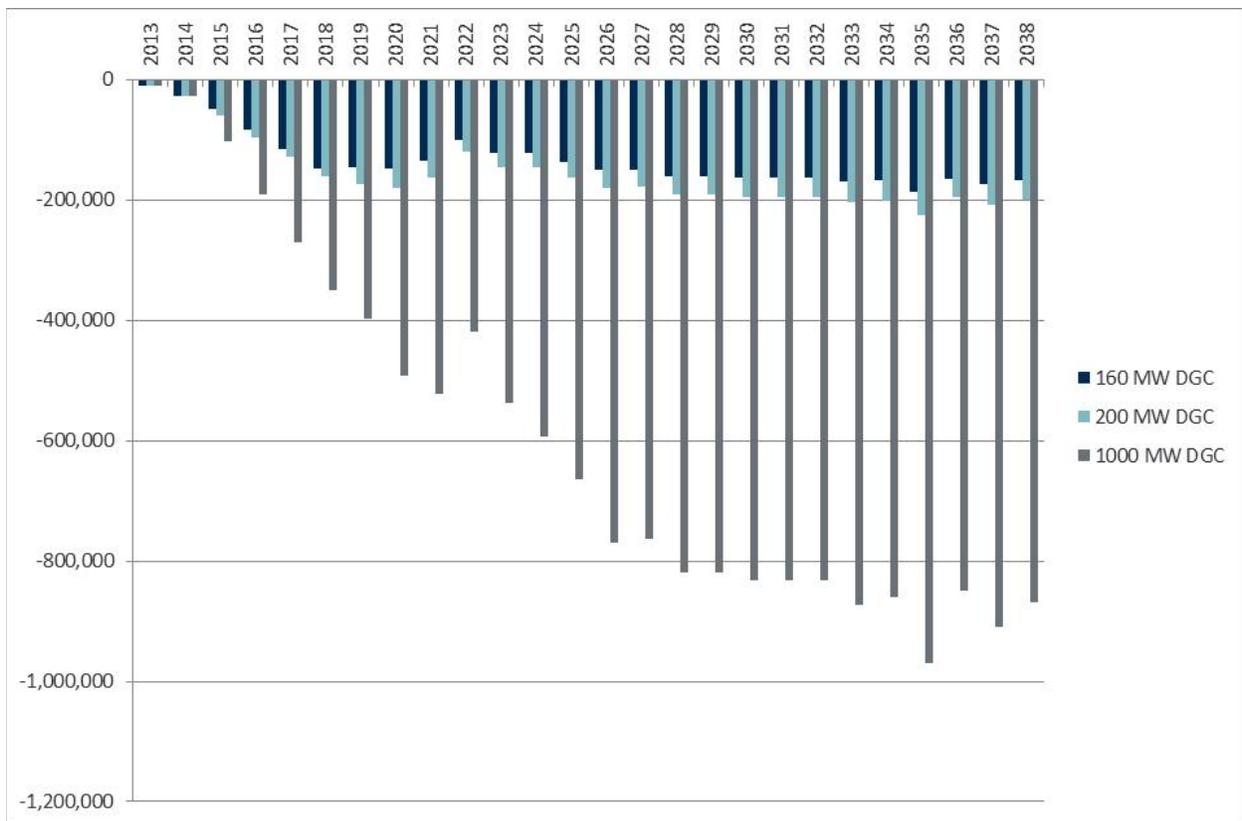


Figure B2: SO2 Emissions Changes (Tons)

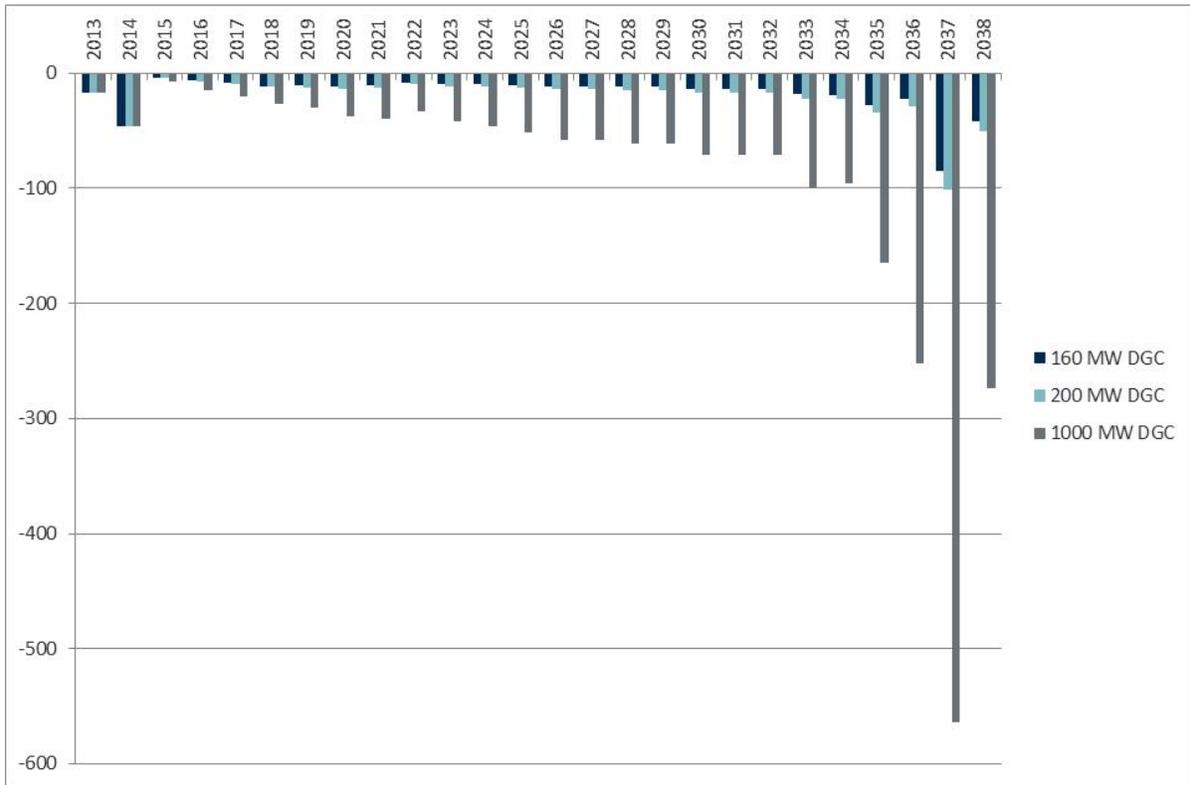


Figure B3: NOx Emissions Changes (Tons)

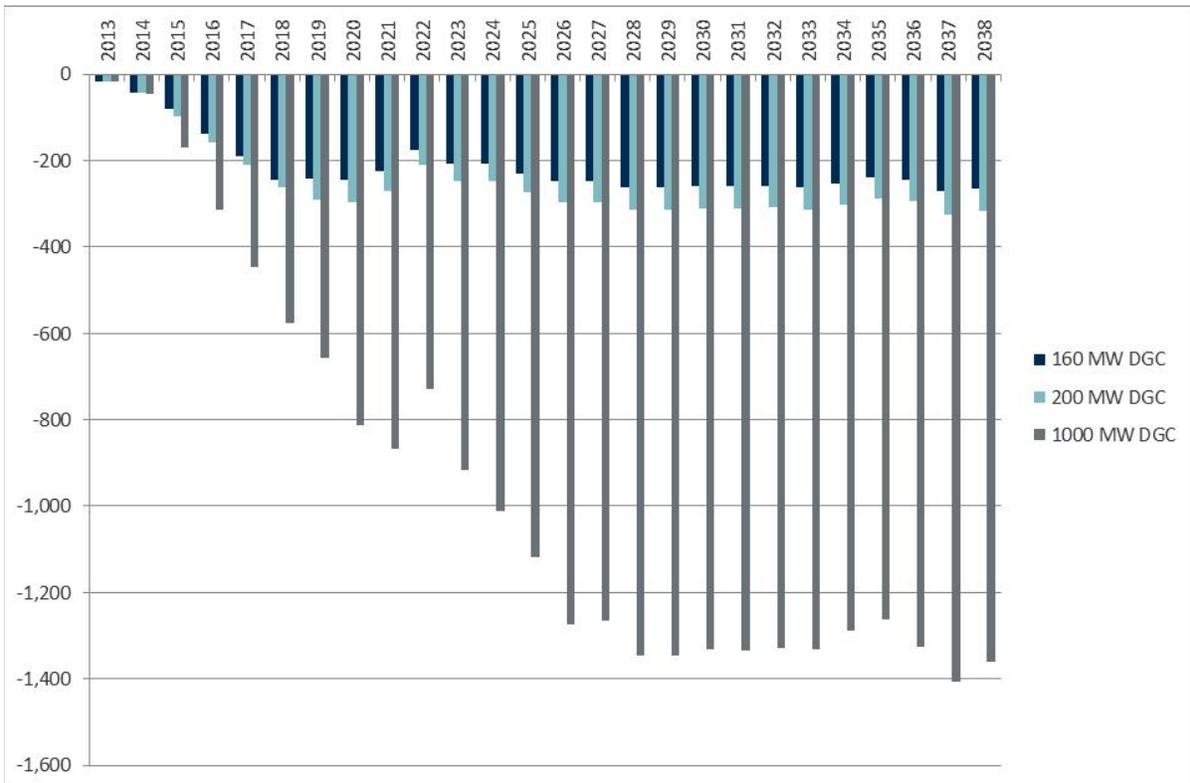


Figure B4: PM-10 Emissions Changes (Tons)

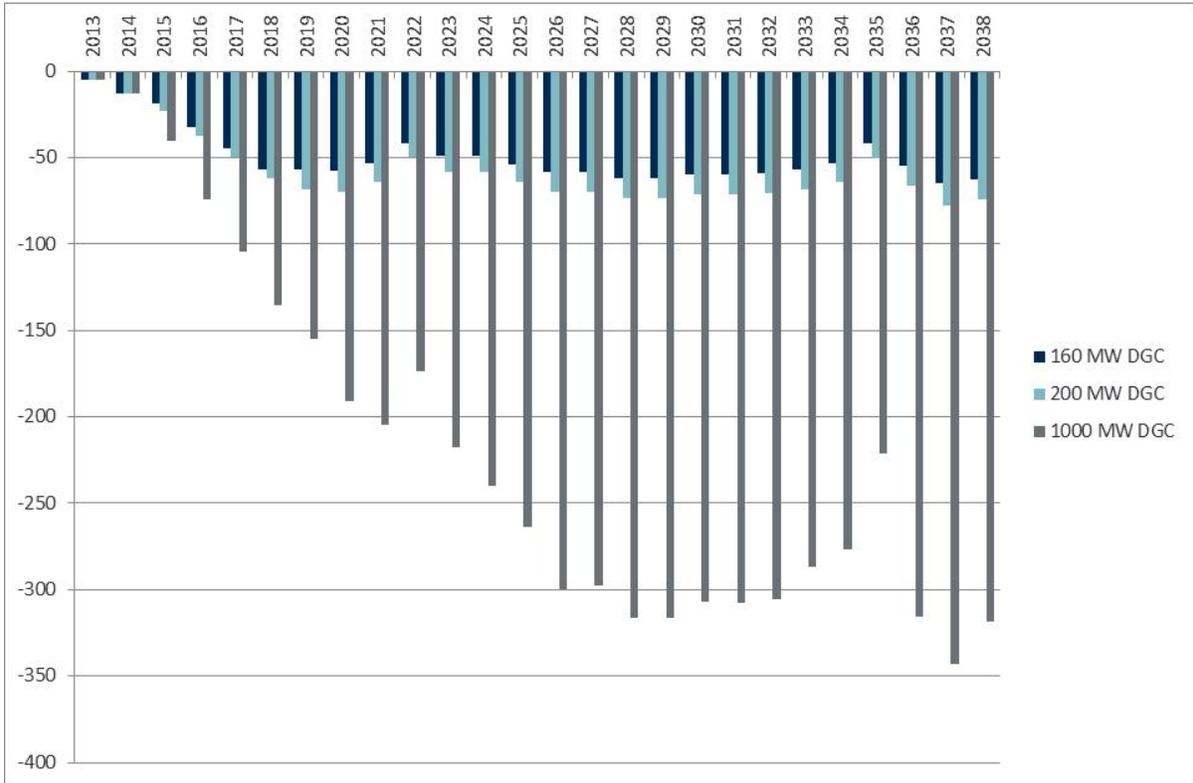
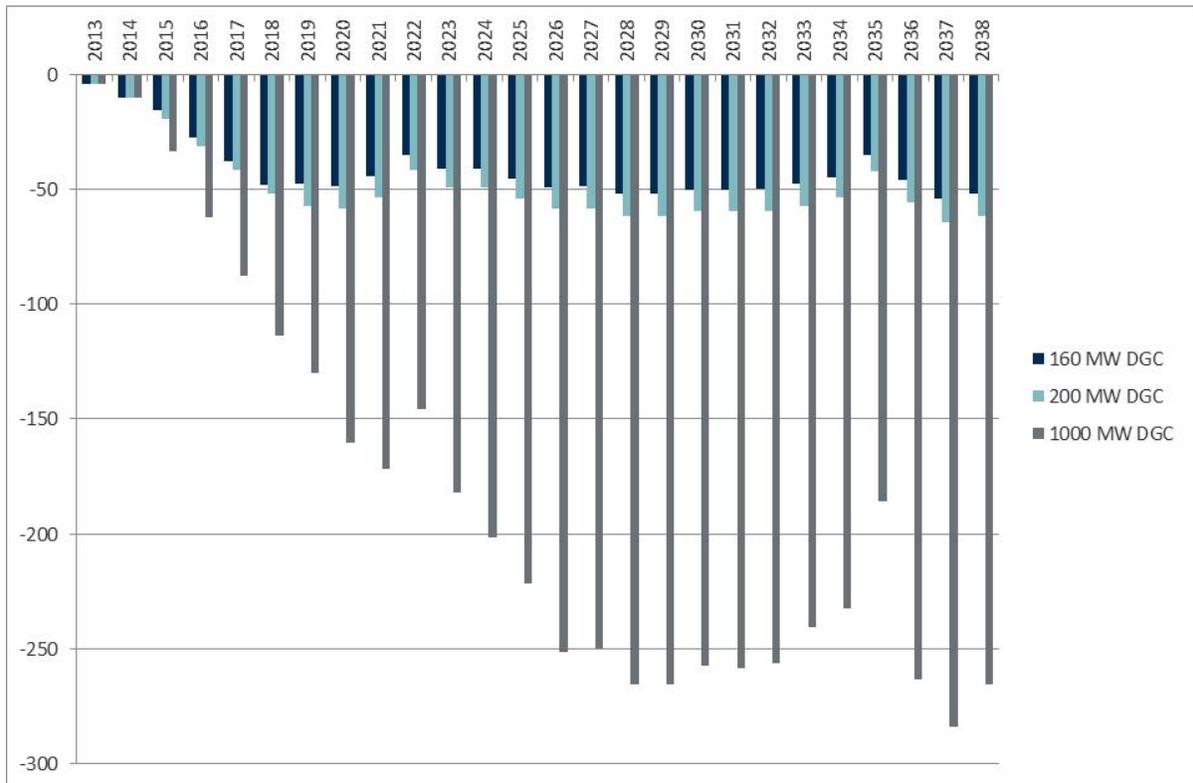


Figure B5: PM-2.5 Emissions Changes (Tons)



B. ALLOWANCE COSTS

Figure B6 shows CO2 allowance cost changes by year from the DGSC and REF programs. Figure B7 shows NOX allowance cost changes by year from the DGSC and REF programs.

Figure B6: CO2 Allowance Cost Changes (\$2014)

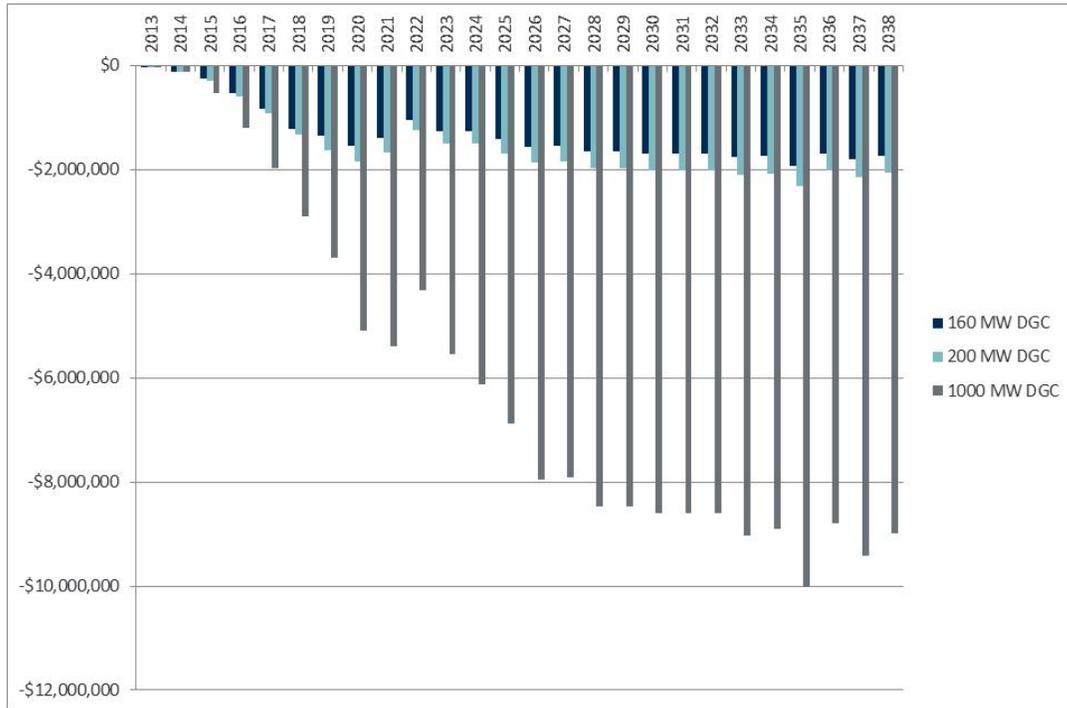
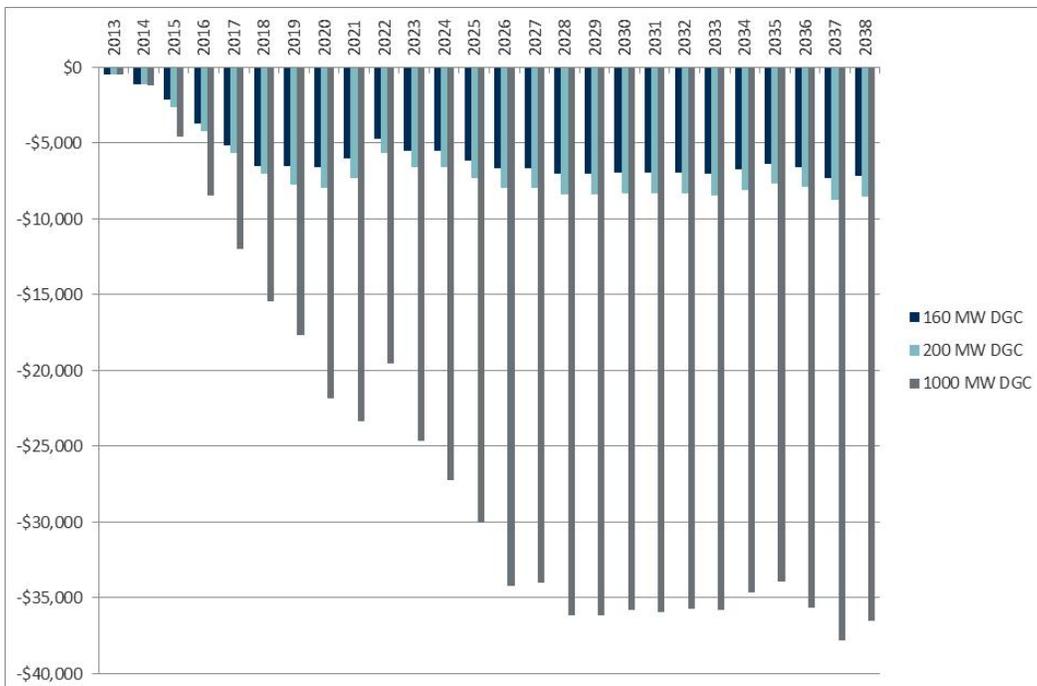


Figure B7: NOX Allowance Cost Changes (\$2014)



C. DAMAGES

Figure B8 shows CO2 damage cost changes by year from the DGSC and REF programs. Figure B9 shows SO2 damage cost changes by year from the DGSC and REF programs. Figure B10 shows NOX damage cost changes by year from the DGSC and REF programs. Figure B11 shows PM-10 damage cost changes by year from the DGSC and REF programs. Figure B12 shows PM-2.5 damage cost changes by year from the DGSC and REF programs.

Figure B8: CO2 Damage Cost Changes

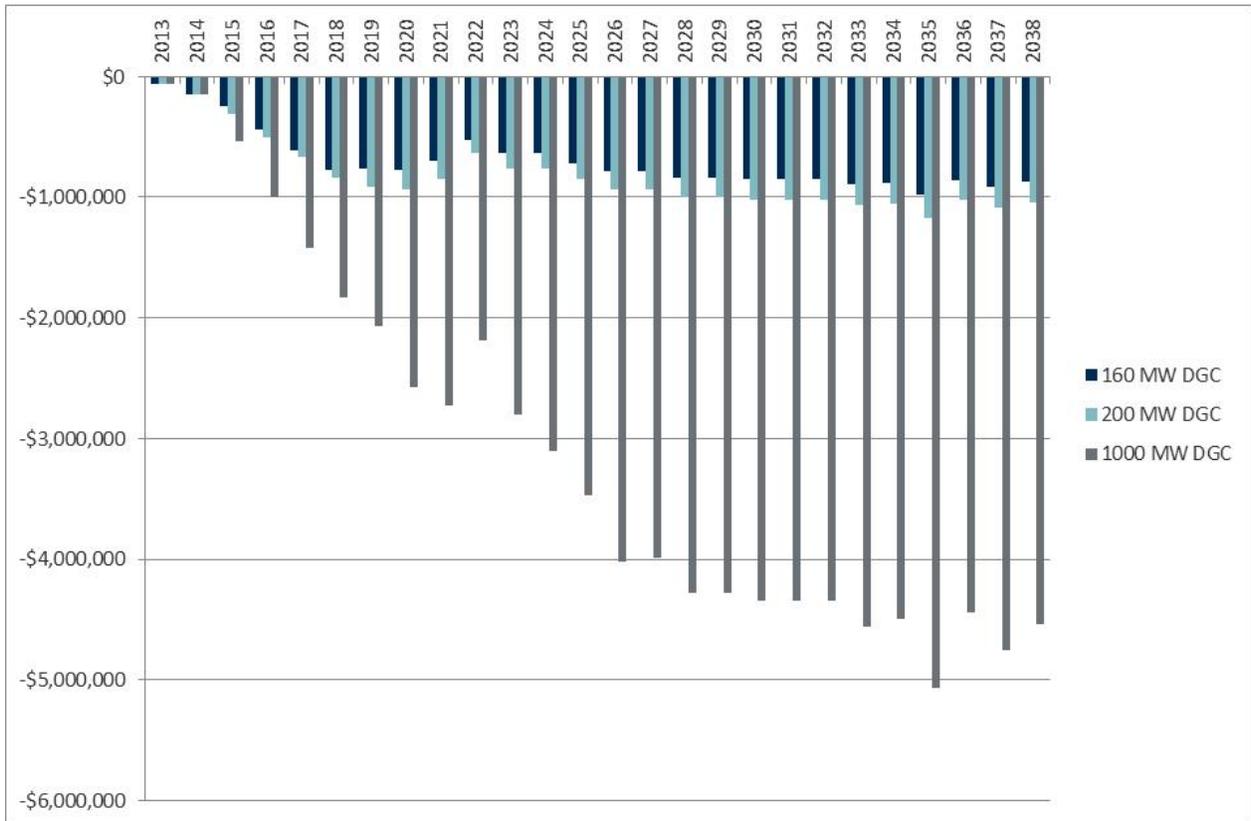


Figure B9: SO2 Damage Cost Changes (\$2014)

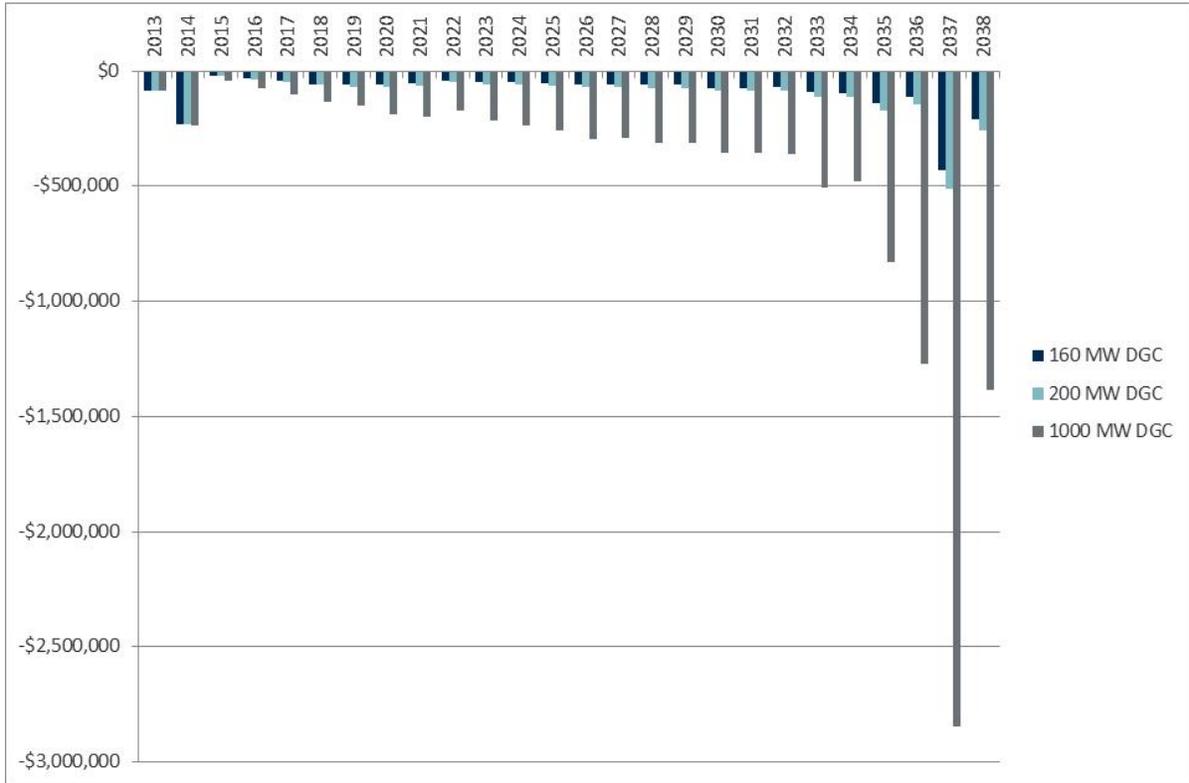


Figure B10: NOX Damage Cost Changes (\$2014)

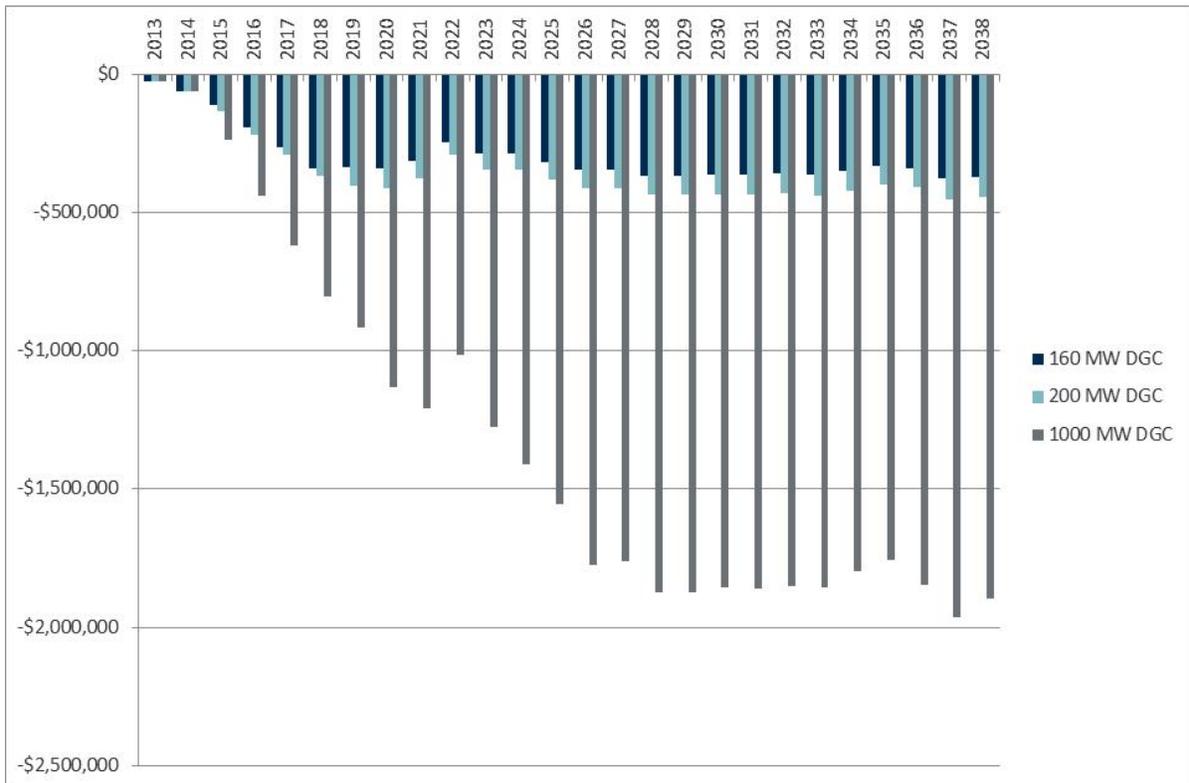


Figure B11: PM-10 Damage Cost Changes (\$2014)

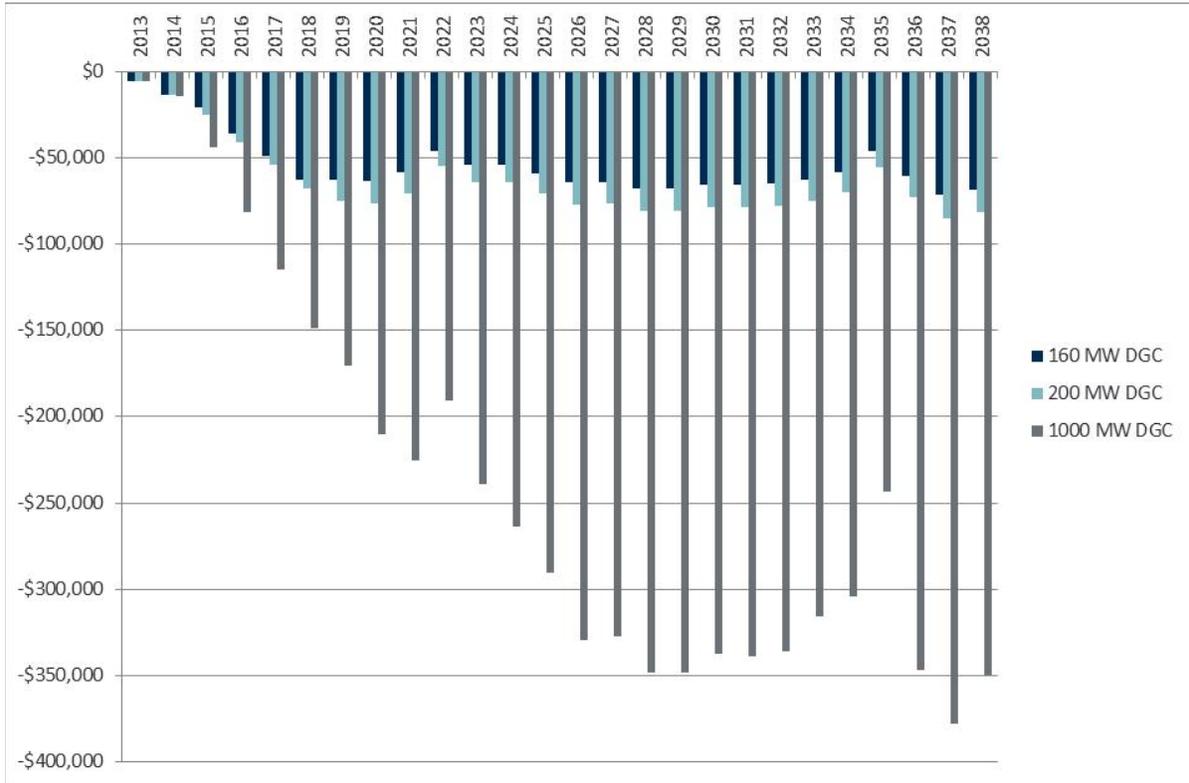
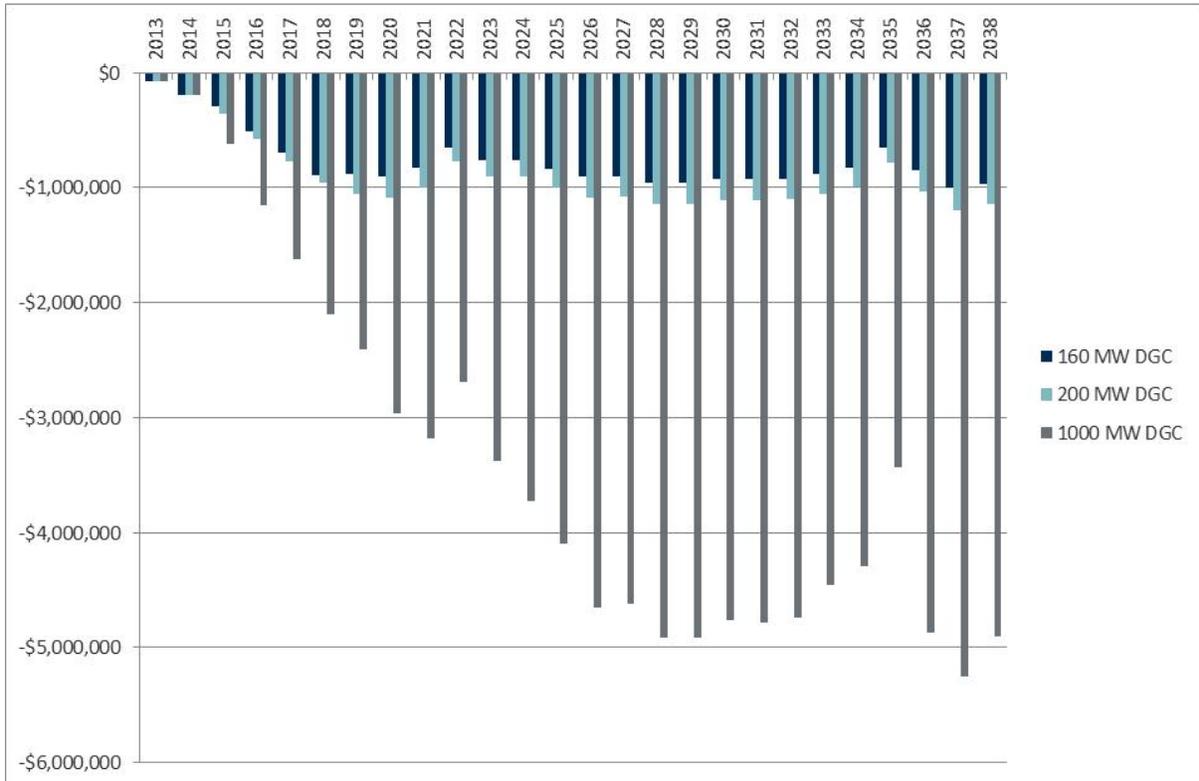


Figure B12: PM-2.5 Damage Cost Changes (\$2014)



IX. Appendix C: Economic and Environmental Impacts of DGSC and REF Scenarios under High Gas Price Case

A. SUMMARY OF RESULTS

Table C1A presents the average annual impacts of the DGSC and REF programs under a case where gas prices are higher than expected (as shown in Figure 4). Table C1B presents net present value impacts of the DGSC and REF programs under a case where gas prices are higher than expected. Table C2A presents the average annual ratepayer impacts of the DGSC and REF programs. Table C2B presents the net present value ratepayer impacts of the DGSC and REF programs.

Table C1A: Average Annual Impacts of DGSC and REF Programs

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Economic Output (\$2014 MM)	\$29.61	\$35.18	\$131.53
Employment (FTE Jobs)	243	290	1,088
State Tax Impacts (\$2014 MM)	\$0.98	\$1.17	\$4.18
CO2 Damage Cost Reductions (\$2014 MM)	\$0.73	\$0.87	\$3.33
SO2 Damage Cost Reductions (\$2014 MM)	\$0.22	\$0.25	\$1.13
NOX Damage Cost Reductions (\$2014 MM)	\$0.30	\$0.36	\$1.37
PM-10 Damage Cost Reductions (\$2014 MM)	\$0.06	\$0.07	\$0.25
PM-2.5 Damage Cost Reductions (\$2014 MM)	\$0.78	\$0.92	\$3.52

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.

Table C1B: Net Present Value Impacts of DGSC and REF Programs (\$2014 MM)

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Economic Output	\$539	\$638	\$2,282
State Tax Impacts	\$15	\$17	\$59
CO2 Damage Cost Reductions	\$13	\$16	\$58
SO2 Damage Cost Reductions	\$4	\$4	\$18
NOX Damage Cost Reductions	\$5	\$6	\$24
PM-10 Damage Cost Reductions	\$1	\$1	\$4
PM-2.5 Damage Cost Reductions	\$14	\$17	\$61

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.

Table C2A: Average Annual Ratepayer Impacts of DGSC and REF Programs (\$2014 MM)

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Ratepayer Price Suppression Savings	\$0.80	\$0.95	\$3.66
Ratepayer Program Costs	-\$17.93	-\$20.94	-\$136.61
Net Ratepayer Impacts	-\$17.13	-\$19.98	-\$132.94

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.

Table C2B: Net Present Value Ratepayer Impacts of DGSC and REF Programs (\$2014 MM)

Category	160 MW DGC	200 MW DGC	1000 MW DGC
Ratepayer Price Suppression Savings	\$14	\$17	\$63
Ratepayer Program Costs	-\$367	-\$427	-\$2,676
Net Ratepayer Impacts	-\$353	-\$411	-\$2,613

Notes:

In addition to the capacity additions listed in the table, each scenario also includes 40 MW of DGSC capacity, already committed, and between 5 and 10 MW of REF capacity anticipated through 2018.