# The Impact of Energy Efficiency and Demand Response Programs on the U.S. Electricity Market

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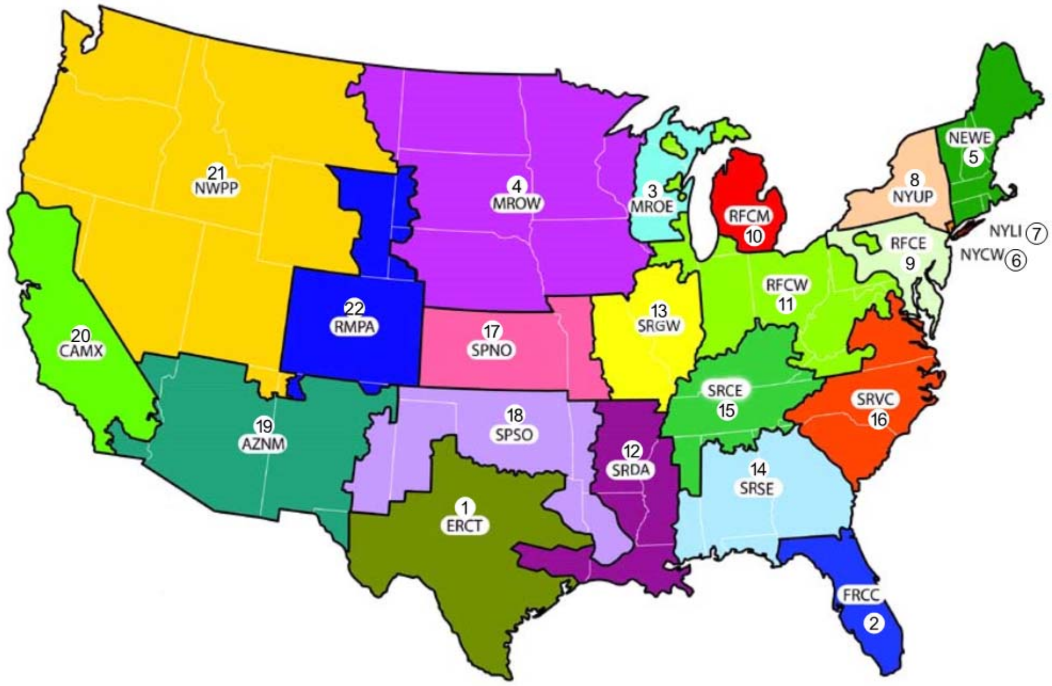
**ABSTRACT**

This study analyzes the impact of the energy efficiency (EE) and demand response (DR) programs on the grid and the consequent level of production. Changes in demand caused by EE and DR programs affect the dispatch of existing plants and new generation technologies, the retirements of old plants, and the finances of the market. To find the new equilibrium in the market, we use the Oak Ridge Competitive Electricity Dispatch Model (ORCED) developed to simulate the operations and costs of regional power markets depending on various factors including fuel prices, initial mix of generation capacity, and customer response to electricity prices. In our analysis, we show changes in generation, price, revenue, and $CO_2$ emissions across regions.

## Introduction

Energy efficiency (EE) and demand response (DR) have been a growing part in energy policy agenda in the United States. The American Recovery and Reinvestment Act of 2009 (ARRA 2009) has provisions supporting energy efficiency and demand response programs. The evolution of energy efficiency and demand response programs have been expected to reduce electricity consumption by 5~15% in a decade from today (Faruqui and Mitarotonda 2011). As utility-sponsored EE and DR programs have expanded and relative regulations and policies have evolved, various studies have been conduced to understand the impact of the EE and DR programs on the power market (FERC 2011; Cappers et al. 2010; Faruqui and Mitarotonda 2011; Spees and Lave 2007; Albadi 2007; Levine et al. 1995; Brown et al. 2010). Whereas many studies have focused on the engineering and economic potential of the technologies and programs, relatively few studies have analyzed the holistic impact on the structure and the dynamics of the market. Changes in demand caused by EE and DR programs would affect not only the dispatch of existing plants but also the additions of advanced generation technologies, the retirements of old coal-firing plants, and the finances of the market. We analyze the impact of the EE and DR programs on the grid and the consequent level of production by fuel type. To find the new market equilibrium, we use the Oak Ridge Competitive Electricity Dispatch Model (ORCED) developed to simulate the operations and costs of regional power markets depending on various factors including fuel prices, initial mix of generation capacity, and customer response to electricity prices (Hadley 2008; Hadley 1998; Hirst and Hadley 1999). In ORCED, over 19,000 plant units in the nation are aggregated into up to 200 plant groups per region. Then, ORCED dispatches the power plant groups in each region to meet the electricity demands for a given year up to 2035. In our analysis, we show various demand, supply, and dispatch patterns affected by EE and DR programs across EIA (Energy Information Administration)'s 22 Electricity Market Module regions (Figure 1).

**Figure 1. EIA's Electricity Market Module Regions**[1]
(Image Source: Annual Energy Outlook 2011, EIA)




## Scenarios for Energy Efficiency and Demand Response Programs

To see how EE and DR influence the electricity grid in the year 2020, this study developed three different scenarios depending on the magnitude of electricity savings and the time slot when the savings happen. The range of % savings is set according to Faruqui and Mitarotonda's energy experts survey (2011).

- **Business-as-usual (BAU) scenario:** This scenario follows the EIA's Annual Energy Outlook 2011 (AEO 2011) reference case. It generally assumes that current laws, regulations, and programs affecting the energy sector remain unchanged throughout the projection.
- **Expanded EE scenario:** This scenario assumes that expanded EE programs lead to a 5% decrease (on average across regions) in electricity consumption over the year 2020 versus BAU.

[1] 1 ERCT (ERCOT All); 2 FRCC (FRCC All); 3 MORE (MRO East), 4 MROW (MRO West); 5 NEWE (NPCC New England); 6 NYCW (NPCC NYC/Westchester); 7 NYLI (NPCC Long Island); 8 NYUP (NPCC Upstate NY); 9 RFCE (RFC East); 10 RFCM (RFC Michigan); 11 RFCW (RFC West); 12 SRDA (SERC Delta); 13 SRGW (SERC Gateway); 14 SRSE (SERC Southeastern); 15 SRCE (SERC Central); 16 SRVC (SERC VACAR); 17 SPNO (SPP North); 18 SPSO (SPP South); 19 AZNM (WECC Southwest); 20 CAMX (WECC California); 21 NWPP (WECC Northwest); 22 RMPA (WECC Rockies)

- **Expanded DR scenario:** This scenario assumes that the national peak demand declines consistently by up to 14% during the peak hours, compared to what it would have been without incremental improvements in DR programs. This scenario refers to specific time periods representing when DR has a high probability of being used. The "peak hours" on a "typical event day" is defined as hours between 2 and 6 pm on the top 15 system load days (FERC 2009). Regional differences in % of DR savings are applied. This scenario does not consider load shifting between peak and off-peak hours.

## Data and Projections

This study uses two publicly available datasets to set the supply and demand levels of the BAU case. The Annual Electric Balancing Authority Area and Planning Area Report of the Federal Energy Regulatory Commission (FERC 714) is used to update Load Duration Curves (LDCs) of the demand module. FERC 714 contains hourly load by utilities or their regional system operators. Daylight saving time by utilities is adjusted to have a consistent time format across regions. Some utilities place a zero for the missing hour in March and combine two hours values in November, while others report their loads using standard time for entire year; there are other variations as well. Hourly load graphs for several days before and after the spring and fall shift are compared to ensure consistency. Because the data on the hourly in-flows or out-flows are not available in FERC 714, the total net energy load for a region in AEO 2011 is used to adjust the load reflecting imports and exports of electricity of the region. This provides the hourly loads that internal generating plants would have to provide.

The raw data of the supply module is updated by 2011 input data for the Electricity Market Module (EMM) of EIA's National Energy Modeling System (NEMS). AEO 2011 re-classifies the old 13 EMM regions into 22 subregions. Input file Pltf860.txt in NEMS provides various information of summer/ winter capacity, heat rate, emission rates of $NO_X$ and $SO_X$ of 18,570 existing and planned plants. This study also uses the cumulative unplanned additions forecast of AEO2011 to consider not only the existing and planned plants but also 525 unplanned (but expected) plant additions in the year 2020.

## Methodology

This study uses ORCED model to simulate the operations and costs of regional power markets depending on various factors including fuel prices, initial mix of generation capacity, and customer response to electricity prices. ORCED consists of three modules of supply, demand, and dispatch.

- **Demand Module:** The year 2010 hourly loads were retrieved from all utilities that submitted data to the FERC 714 database. In addition, data from regional transmission organizations were accessed. These were consolidated into the 22 EMM regions and escalated to meet the 2020 demands from the AEO2011 reference case. The 5% EE case simply reduced each hour's load by 5%. For the DR scenario, in each region we determined the 15 days with highest demands and lowered the demands between 2 pm and 6 pm on those days only. The demand module then consolidates the 8760 hours of demands into three Load Duration Curves (LDC), one each for summer, winter, and off-peak seasons.

- **Supply Module:** The list of units for each region that are operating in 2020 are consolidated into up to 200 power plant groups based on their technology, fuel type, and operating cost. For each season, the 200 plants from Supply are sorted in order of increasing variable costs. The order may be different in each season because some costs (e.g., $NO_X$ emission credits) might only be added to the summer season, depending on the scenario. The power capacities are adjusted for planned and forced outages.
- **Dispatch Module:** This module dispatches plant groups created in the supply module to meet the demand. The steps involved begin with altering the LDCs for hydro and pumped storage production. It then proceeds to dispatch the plants for each season using a modified Balleriaux-Booth procedure for unserved energy calculations follow (Vardi and Avi-Ithak 1981). Figure 2 shows an example of the LDC for a region along with the types of pants that are used to fulfill those demands. Some plants are most effective at providing power essentially all the time, or "baseload" power. They typically have low variable costs but may have high fixed costs. Intermediate or "load-following" plants are called on to meet the demand of a significant fraction of the year but will still cycle on and off. Peaking plants are called on least frequently, during high demand times only to meet capacity emergencies. They have the highest marginal costs but typically have low fixed costs either because of their low-cost technology or because they are old, fully depreciated plants. The amount of generation by each plant is then calculated. Lastly, time-dependent prices and revenues are calculated. ORCED has the capability for a plant to use a price other than its variable cost for its bid price into the market. By default, ORCED sets the price of "must-run" and intermittent plants to zero so that they are always called upon. The seasonal results are then combined for a yearly result. Emissions and other financial parameters are last to be calculated. Since demand fluctuate over the year, some plants are called on more often than others in the electricity supply portfolio.

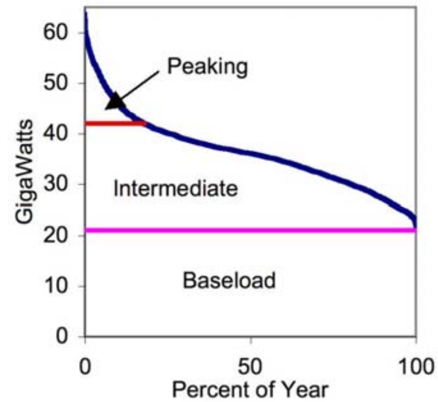



**Figure 2. LDC and Different Power Plant Classes**

## Results

We ran three sets of cases (BAU, EE, and DR) with ORCED for 22 different EMM regions separately. A comprehensive analysis for the nation and a detailed sample analysis for a region, ERCT (TX), in year 2020 are presented in this section. We analyzed the changes in dispatch pattern with three major generation sources of coal, gas, and nuclear. The nation could reduce 209.73 TWh of electricity generation by EE programs but just 4.53 TWh by DR programs in year 2020 (Table 1). There would be a big difference in generation between EE and DR. However, in peak demand reduction, the impact of DR (18.67 GW) would be comparable to that of EE (40.39 GW). EE would significantly contribute to the reduction in $CO_2$ emissions (142.76 million Ton). A decrease in revenue that is proportional to the generation reduction was also shown. Because relatively expensive generating options are involved to meet peak demands in general, DR is expected to subdue the increase in average electricity price. EE could contribute to reducing a significant amount of Green House Gas (GHG) emissions in that EE shifts down the absolute levels of electricity consumption across the entire year. Some regions where the peak demand is served by a variety of other generation options which are cleaner than fossil fuels might not be able to expect a significant reduction in GHG emission from DR because the replaced generation option for serving the highest demand could be less expensive (in terms of operating cost), but a higher emitter of GHGs.

**Table 1 Changes in Outputs in 2020**

| Region | Generation (TWh) | | Peak Demand (GW) | | $CO_2$ (Million Ton) | | Revenue (Billion $) | | Average Cost (¢/kWh) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | EE | DR | EE | DR | EE | DR | EE | DR | EE | DR |
| **ERCT** | -17.52 | -0.28 | -3.60 | -3.51 | -7.93 | -0.17 | -3.66 | -2.04 | -0.81 | -0.59 |
| **FRCC** | -12.13 | -0.22 | -2.31 | -1.12 | -5.52 | -0.10 | -1.06 | -0.04 | -0.15 | -0.01 |
| **MROE** | -1.84 | -0.03 | -0.35 | -0.14 | -1.53 | -0.03 | -0.14 | -0.02 | -0.25 | -0.08 |
| **MROW** | -10.83 | -0.33 | -1.95 | -0.07 | -10.72 | -0.21 | -0.96 | -0.06 | -0.28 | -0.02 |
| **NEWE** | -6.57 | -0.16 | -1.36 | -0.13 | -2.96 | -0.08 | -0.77 | -0.33 | -0.41 | -0.26 |
| **NYCW** | -2.60 | -0.09 | -0.55 | -0.16 | -1.10 | -0.05 | -0.16 | -0.03 | 0.03 | -0.11 |
| **NYLI** | -1.08 | -0.03 | -0.28 | -0.23 | -0.61 | -0.04 | -0.21 | -0.09 | -1.16 | -0.79 |
| **NYUP** | -4.16 | -0.13 | -0.85 | -0.21 | -2.26 | -0.05 | -0.26 | 0.00 | -0.17 | 0.00 |
| **RFCE** | -14.99 | -0.46 | -3.08 | -1.00 | -10.00 | -0.35 | -2.54 | -1.04 | -0.67 | -0.34 |
| **RFCM** | -5.60 | -0.17 | -1.06 | -0.43 | -3.55 | -0.12 | -0.78 | -0.19 | -0.53 | -0.17 |
| **RFCW** | -29.04 | -0.49 | -5.36 | -2.32 | -27.28 | -0.23 | -1.60 | -0.15 | -0.13 | -0.02 |
| **SRDA** | -7.25 | -0.15 | -1.36 | -0.48 | -3.05 | -0.09 | -0.54 | -0.05 | -0.15 | -0.03 |
| **SRGW** | -5.80 | -0.19 | -1.10 | -0.24 | -5.52 | -0.11 | -0.41 | -0.05 | -0.18 | -0.03 |
| **SRSE** | -12.90 | -0.25 | -2.44 | -0.44 | -9.01 | -0.09 | -0.85 | -0.02 | -0.16 | 0.00 |
| **SRCE** | -12.54 | -0.25 | -2.32 | -0.58 | -11.70 | -0.13 | -0.78 | -0.06 | -0.20 | -0.02 |
| **SRVC** | -16.62 | -0.31 | -3.12 | -1.36 | -15.20 | -0.18 | -1.19 | -0.08 | -0.23 | -0.02 |
| **SPNO** | -3.71 | -0.13 | -0.76 | -0.34 | -3.54 | -0.10 | -0.48 | -0.13 | -0.53 | -0.18 |
| **SPSO** | -7.75 | -0.24 | -1.56 | -1.12 | -3.47 | -0.14 | -0.83 | -0.24 | -0.28 | -0.15 |
| **AZNM** | -7.10 | -0.14 | -1.51 | -1.34 | -2.90 | -0.06 | -0.47 | -0.02 | -0.09 | -0.01 |
| **CAMX** | -14.33 | -0.26 | -2.98 | -2.58 | -5.35 | -0.10 | -0.83 | -0.02 | -0.10 | 0.00 |
| **NWPP** | -11.72 | -0.17 | -1.87 | -0.65 | -6.32 | -0.10 | -1.11 | -0.01 | -0.30 | 0.00 |
| **RMPA** | -3.65 | -0.06 | -0.63 | -0.21 | -3.23 | -0.03 | -0.44 | 0.00 | -0.44 | 0.00 |
| **Total** | -209.73 | -4.53 | -40.39 | -18.67 | -142.76 | -2.56 | -20.08 | -4.67 | | |

We found that the electricity generated from coal and gas would decrease in most of the regions under both Expanded EE and DR scenarios (Table 2). On the other hand, any significant change in nuclear-based generation was not noticed. Under the EE scenario, the level of generation reduction out of coal (100.66 TWh) was comparable to that from gas (106.28 TWh). Under the Expanded DR case, however, the total reductions in coal-electricity (0.27 TWh) and gas-electricity (3.97 TWh) were noticeably different. This result is explained by the fact that EE programs are implemented to shift down the level of electricity demand by adopting energy-efficient technologies, on the other hand, DR is designed to cope with supply-deficiency situations during the peak hours. In addition, while gas is used for meeting not only base load but also marginal peak demand, coal is generally used for base load in many regions. Regionally, RFCW is the major contributor to reduced coal consumption under EE case, with SRVC next largest. Because ERCT (TX) generates most of its electricity with gas, the region reduces the most gas-based electricity under the Expanded EE scenario.

## Table 2. Changes in Electricity Generation by Fuel in 2020

| Region | Scenario | Coal | | Gas | | Nuclear | |
|---|---|---|---|---|---|---|---|
| | | (TWh) | (% Change) | (TWh) | (% Change) | (TWh) | (% Change) |
| **ERCT** | **EE** | -0.96 | -0.66% | -16.50 | -12.74% | 0.00 | 0% |
| | **DR** | -0.01 | -0.01% | -0.24 | -0.18% | 0.00 | 0% |
| **FRCC** | **EE** | -1.29 | 0.00% | -10.51 | -0.32% | 0.00 | 0% |
| | **DR** | 0.00 | 0.00% | -0.22 | -0.31% | 0.00 | 0% |
| **MROE** | **EE** | -1.19 | -6.44% | -0.65 | -28.18% | 0.00 | 0% |
| | **DR** | -0.01 | -0.08% | -0.02 | -0.73% | 0.00 | 0% |
| **MROW** | **EE** | -9.66 | -6.26% | -0.97 | -20.83% | 0.00 | 0% |
| | **DR** | -0.11 | -0.07% | -0.21 | -4.51% | 0.00 | 0% |
| **NEWE** | **EE** | -0.49 | -3.49% | -5.85 | -10.46% | 0.00 | 0% |
| | **DR** | 0.01 | 0.08% | -0.11 | -0.19% | 0.00 | 0% |
| **NYCW** | **EE** | 0.00 | (-) | -2.60 | -12.17% | 0.00 | (-) |
| | **DR** | 0.00 | (-) | -0.08 | -0.39% | 0.00 | (-) |
| **NYLI** | **EE** | 0.00 | (-) | -0.94 | -9.48% | 0.00 | (-) |
| | **DR** | 0.00 | (-) | 0.00 | 0.00% | 0.00 | (-) |
| **NYUP** | **EE** | -1.18 | -13.19% | -2.84 | -20.42% | 0.00 | 0% |
| | **DR** | 0.00 | 0.00% | -0.13 | -0.95% | 0.00 | 0% |
| **RFCE** | **EE** | -6.84 | -4.38% | -7.46 | -30.35% | 0.00 | 0% |
| | **DR** | 0.00 | 0.00% | -0.34 | -1.38% | 0.00 | 0% |
| **RFCM** | **EE** | -2.27 | -3.15% | -3.05 | -16.99% | 0.00 | 0% |
| | **DR** | -0.01 | -0.01% | -0.16 | -0.91% | 0.00 | 0% |
| **RFCW** | **EE** | -27.15 | -6.09% | -1.84 | -38.15% | 0.00 | 0% |
| | **DR** | 0.01 | 0.00% | -0.49 | -10.26% | 0.00 | 0% |
| **SRDA** | **EE** | -0.19 | -0.35% | -7.06 | -10.63% | 0.00 | 0% |
| | **DR** | 0.00 | 0.00% | -0.15 | -0.23% | 0.00 | 0% |
| **SRGW** | **EE** | -5.42 | -4.99% | -0.37 | -47.82% | 0.00 | 0% |
| | **DR** | -0.03 | -0.02% | -0.16 | -20.93% | 0.00 | 0% |
| **SRSE** | **EE** | -8.79 | -5.12% | -4.09 | -22.23% | 0.00 | 0% |
| | **DR** | 0.01 | 0.00% | -0.26 | -1.40% | 0.00 | 0% |
| **SRCE** | **EE** | -11.59 | -7.72% | -0.93 | -42.71% | 0.00 | 0% |
| | **DR** | -0.03 | -0.02% | -0.22 | -10.02% | 0.00 | 0% |
| **SRVC** | **EE** | -14.83 | -10.23% | -1.63 | -26.57% | 0.00 | 0% |
| | **DR** | -0.04 | -0.03% | -0.26 | -4.26% | 0.00 | 0% |
| **SPNO** | **EE** | -3.05 | -7.37% | -0.62 | -29.31% | 0.00 | 0% |
| | **DR** | 0.01 | 0.01% | -0.12 | -5.64% | 0.00 | 0% |
| **SPSO** | **EE** | -0.18 | -0.23% | -7.57 | -13.64% | 0.00 | (-) |
| | **DR** | 0.00 | 0.00% | -0.24 | -0.44% | 0.00 | (-) |
| **AZNM** | **EE** | -0.02 | -0.04% | -7.07 | -12.58% | 0.00 | 0% |
| | **DR** | 0.00 | 0.00% | -0.14 | -0.24% | 0.00 | 0% |
| **CAMX** | **EE** | -0.09 | -0.57% | -13.94 | -17.29% | 0.00 | 0% |
| | **DR** | 0.00 | 0.00% | -0.25 | -0.31% | 0.00 | 0% |
| **NWPP** | **EE** | -2.85 | -3.15% | -8.77 | -38.68% | 0.00 | 0% |
| | **DR** | -0.06 | -0.07% | -0.11 | -0.46% | 0.00 | 0% |
| **RMPA** | **EE** | -2.62 | -4.99% | -1.01 | -22.10% | 0.00 | (-) |
| | **DR** | -0.01 | -0.01% | -0.05 | -1.14% | 0.00 | (-) |
| **Total** | **EE** | -100.66 | | -106.28 | | 0.00 | |
| | **DR** | -0.27 | | -3.97 | | 0.00 | |

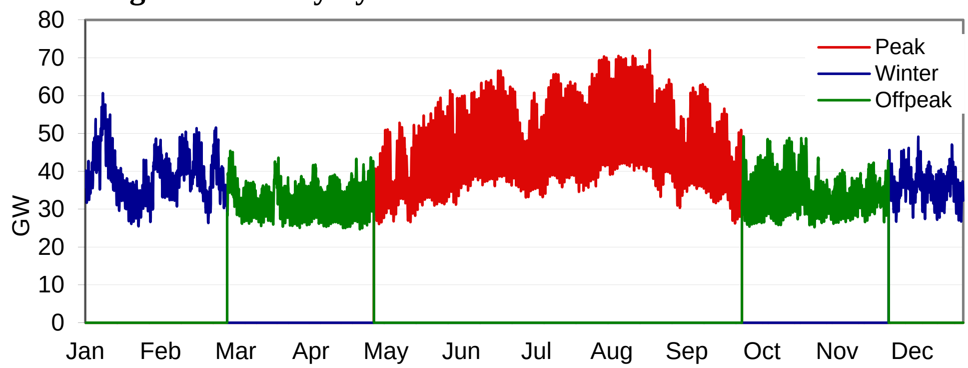
* Other generation sources such as renewables, distillate oil, etc. are not presented in this table, because the scale of generation and the impact of EE and DR on those sources were marginal compared to coal and gas.

## ERCT (TX): A Sample Result[2]

ORCED provides region-by-region results about load changes, electricity production, and dispatch pattern. Due to the space limit assigned for this paper, we present additional and detailed results only for ERCT as a sample. All Results presented in this sub-section show the snapshot of electricity market of the year 2020.

In general, regions have peaks in summer season ranging from July to September. However, some regions have winter peaks as well. FRCC has some winter peak days of January 6-9, January 10-12 as well as typical summer peak days. SRSE, SRCE, and SRVC also have winter peaks of January 11, January 6 and 8, and January 11 respectively. NWPP has some peaks in November and December (Nov. 22-24, Nov. 29 and Dec. 30 and 31). All top 15 expected peak days of ERCT are placed in August (August 2-6, 9-13, 16-17, 20, 22, and 23) (Figure 3).

**Figure 3. Hourly System Load of ERCT in 2020 under BAU**




Expanded EE and DR programs are expected to increase the reserve margin by 7% points in summer in ERCT (Figure 4). DR does not affect the reserve margin of winter and offpeak (Current reports show ERCT having low reserve margins in the near future, but our reserve margin values include full credit for wind capacity as well as additional capacity additions between now and 2020). The two programs will drop the level of annually-unserved energy from 1 GWh to 0 level. In addition, the Loss of Load Probability (LOLP)[3] would drop from 0.88 to 0 days per year under the Expanded DR scenario and from 2.11 to 0 days per year under the Expanded EE scenario even during the summer.

[2] To update inputs in the ORCED demand module for this regional analysis, we used pltf860.v1.148.txt file from EIA's Annual Energy Outlook 2011 (AEO 2011) Early Release, which did not include additional plants stored in WFLOOR.txt file. ORCED with the inputs from the final AEO 2011 may show different results.

[3] Loss of Load Probability (LOLP) is defined as the amount of time that demand exceeds capacity.

**Figure 4. Reserve Margin by Scenario and by Season in 2020**

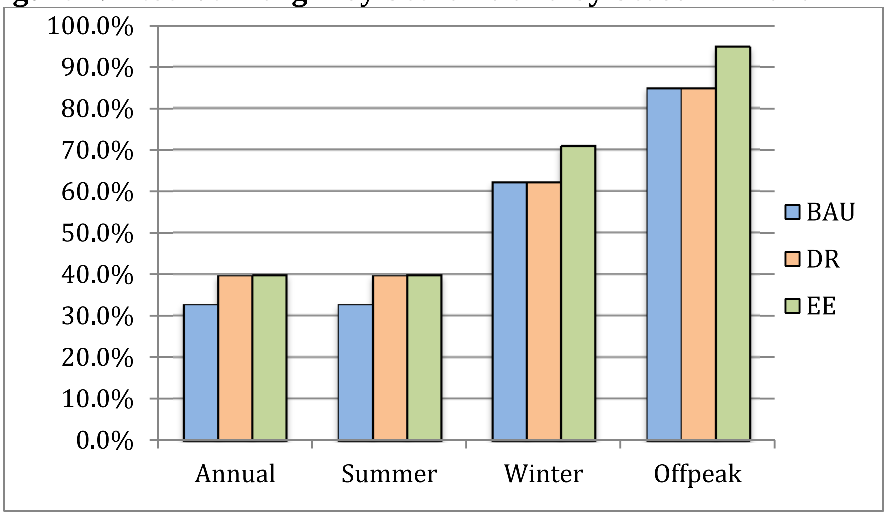



Figure 5 shows how many GWh of electricity is generated over the year. All 365 days, 8760 hours of a year are ordered in demanded power levels. The size of area under projection lines means total electricity generated. EE shifts the BAU's projection curve down by about 5% across the year. On the other hand, the impact of DR is showed only in the first top 10% of the year ( Figure 6).

**Figure 5. Electricity Production Amounts Showing Marginal Time by Scenario**

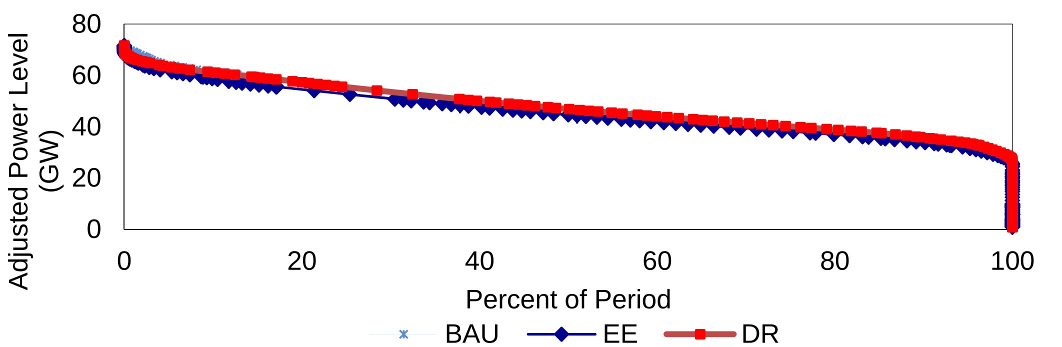
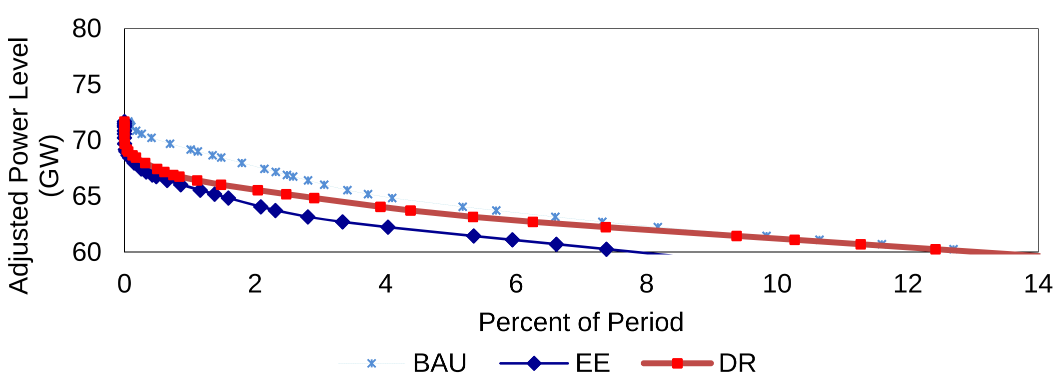
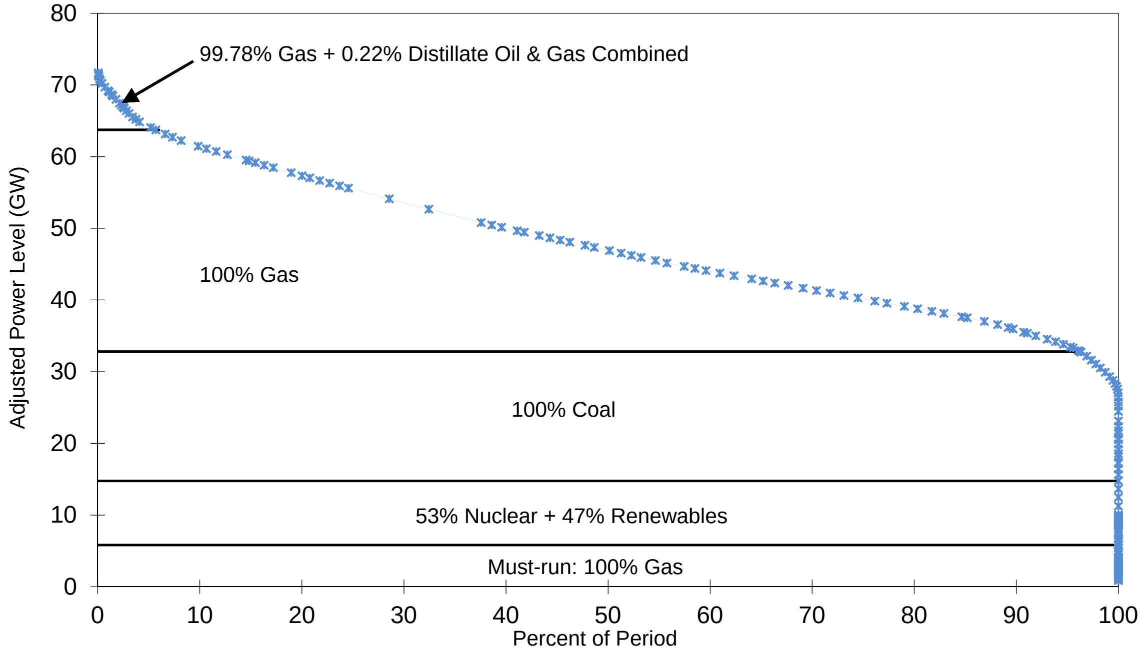



**Figure 6. Impact of DR during Peak Hours (Magnified Image of Figure 5)**



The EE and DR programs are expected to influence changes in dispatch pattern across regions. If a region has a diversified generation portfolio that has a variety of variable costs, its dispatch patterns would change more dynamically than others. In that respect, ERCT (TX) is not a region whose dispatch patterns are affected by energy programs and policies much. As is well known, ERCT is a gas-fired-generation dominant region. Its must-run baseload is comprised of gas-fired plants such as gas turbines and combined-cycle plants (Figure 7). Baseload generation is made up of coal, nuclear, renewables, and must-run plants. Gas generation provides almost all of the generation above baseload. As a consequence, gas-fired generation is the price-setter most of the time. In 96% of the time gas generation is "on the margin" and setting the price, while coal generation sets the price only 4% of the time.

**Figure 7. Dispatch Pattern under BAU Scenario**




ERCT could change its dispatch pattern to serve the highest levels of demand generally served at high price levels. The 0.22% of distillate oil combined plants to be forced to generate electricity during the highest peak time can be replaced with solely gas-fired turbines which are less expensive to operate in general. The replacement is anticipated to happen both under the Expanded EE and DR scenarios (compare Figure 7 with Figure 8 and Figure 9).

**Figure 8. Dispatch Pattern under Expanded EE Scenario**

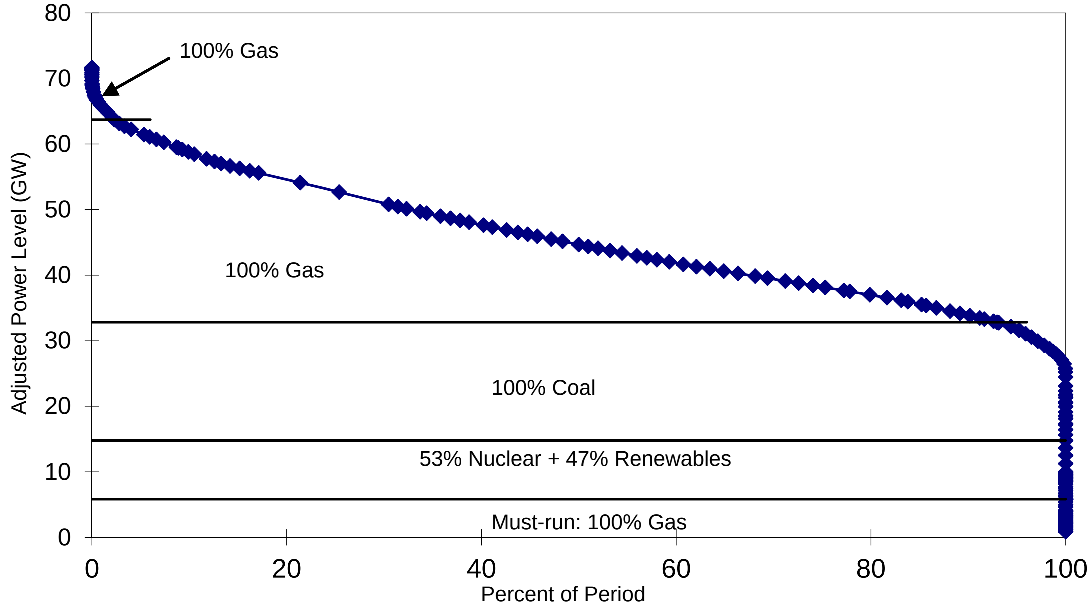
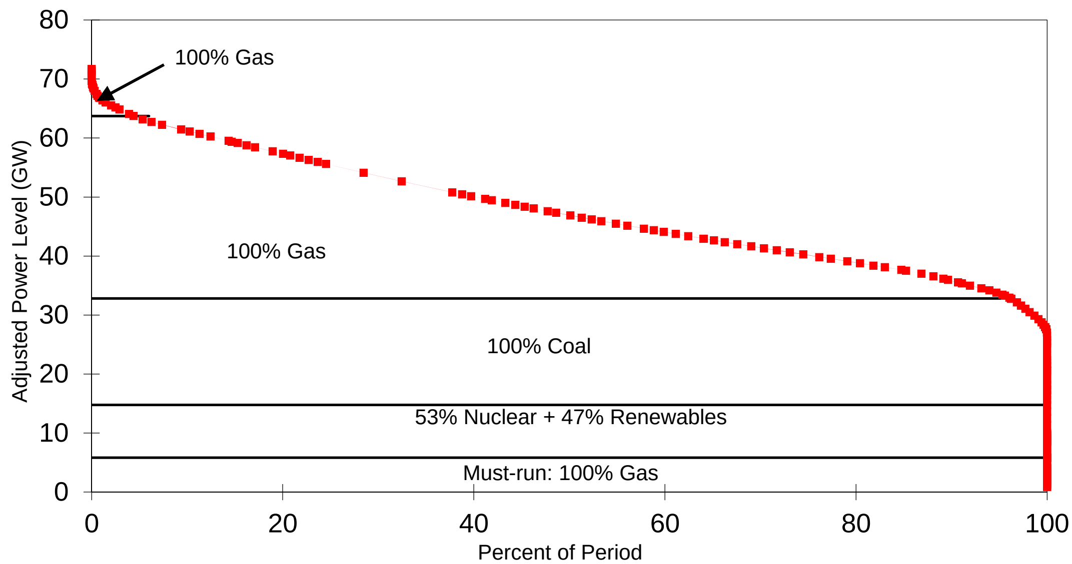



**Figure 9. Dispatch Pattern under Expanded DR Scenario**




At any point in time, whatever plant is the last plant being dispatched, it is considered as being "on the margin." In other words, the plant dispatched last in a time slot becomes the marginal price setter of the time period. In a deregulated market, its variable cost of production would set the wholesale market price for power for itself and all other plants lower in the dispatch order. Because the variable cost of the intra marginal plants are lower than the marginal plants. Figure 10 shows seasonally-different price levels in ERCT in 2020. The EE programs have a significant impact on subduing prices set for top 20% of electricity consumption in 2020. By the definition of peak time period by FERC, 2-6 pm of top 15 peak days is equivalent to top 0.68% of year ordered in demand level. A magnified image of Figure 10 shows what happens in the very demanding time slot (Figure 11).

**Figure 10. Seasonal Prices of ERCT in 2020**

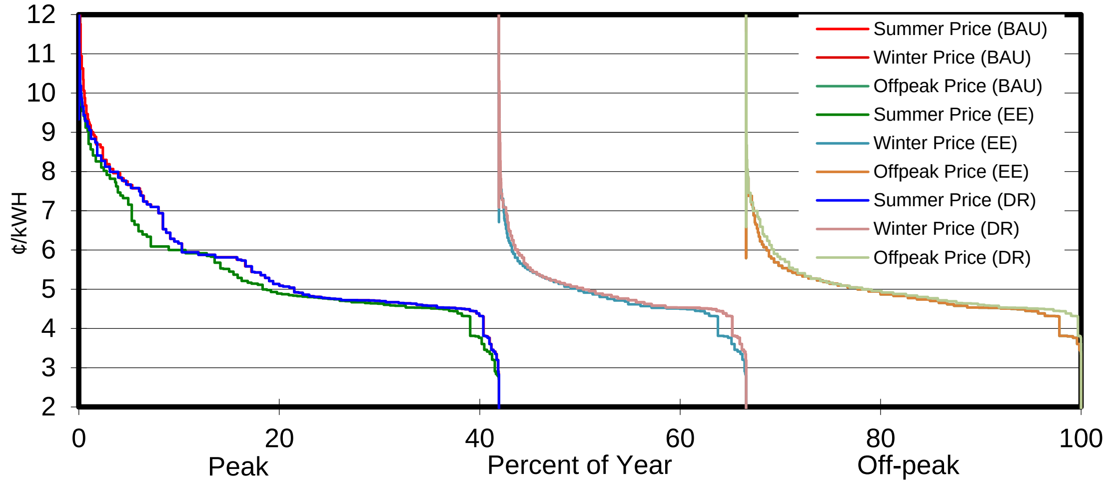
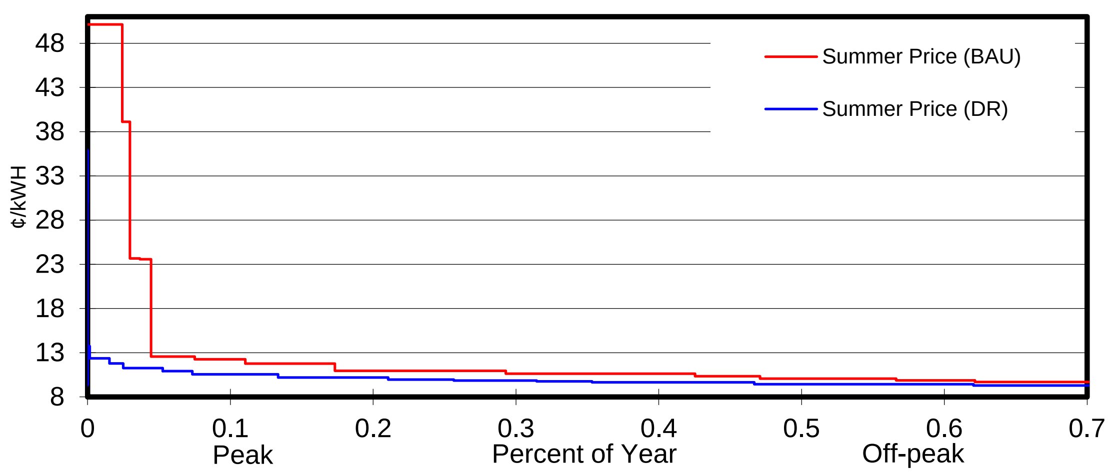



**Figure 11. Prices of Top 0.7% Electricity Demand**




## Conclusions

This study analyzed three different cases of BAU, Expanded EE, and Expanded DR and found that the two programs would significantly affect the generation dispatch pattern, pricing, revenue of utilities, and GHG emissions. While both policies are expected to influence the electricity market in general and contribute to curtailing the fossil fuel consumption for electricity generation, the time slots when the savings happen and the magnitude of the impacts varies tremendously. The impact of EE was distributed across the entire year, whereas that of DR was focused on the peak periods. As a consequence, EE programs have a far larger impact on emissions, fuel use, and revenues. This is because DR is originally designed for emergency controls and grid reliability but EE is implemented for overall load shavings. Expanded EE and DR programs are anticipated to contribute not only to controlling the quantity of electricity supply but also to subduing electricity prices during peak periods.

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