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Indiana Utility Regulatory Commission

NIPSCO

2011 Integrated Resource Plan

November 1, 2011

Volume I

NIPSCO 2011 Integrated Resource Plan ("IRP") Overview

Northern Indiana Public Service Company ("NIPSCO" or the "Company"), serves approximately 457,000 electric customers across the northern third of Indiana, and is the fourth largest electric distribution company in the state. Resources used to serve our customers include company owned generating facilities with a total net demonstrated capability ("NDC") of 3,322 megawatts ("MW") of coal, natural gas and hydroelectric generation, as well as long-term purchases of wind generation with a NDC of 100 MWs. NIPSCO supplements these resources with short-term purchases of energy from the markets operated by the Midwest Independent Transmission System Operator, Inc. ("MISO.)" NIPSCO is a member of MISO.

According to 170 IAC 4-7-3, 170 IAC 4-7 *et seq.* ("Rule 7"), each public, municipally owned and cooperatively owned utility in the State of Indiana is required to submit an Integrated Resource Plan ("IRP") to the Indiana Utility Regulatory Commission ("Commission" or "IURC") every two years. As used in Rule 7, the IRP is the utility's assessment of a variety of demand-side and supply-side resources to cost-effectively meet customer electricity service needs. The information contained herein is compiled and presented in accordance with the guidelines for integrated resource planning by an electric utility as outlined in Rule 7, and in accordance with the Commission Order dated Oct. 14, 2010 in Cause No. 43643.

In this 2011 IRP, NIPSCO sets forth its plan to reliably and cost-effectively meet its customers' future electricity service needs over the next 20 years. The forecasted information presented in this plan addresses the study period of 2012 through 2032 and is based on information available as the plan was prepared. The plan has been created with flexibility and allows for review as needed based on changing circumstances and new information. The long-term plan, as such, may contain general information that may be preliminary in nature; therefore, the plan may change over time as conditions change and information is updated. Specific and detailed data will be submitted through regulatory proceedings and filings, as appropriate.

In this 2011 IRP, the Company discusses the process, methods, models and assumptions used in the IRP development. The 2011 IRP includes various studies, analyses and reports generated by internal subject matter experts within the Company, as well as outside consultants.

This document is organized as follows:

Executive Summary: Outlines NIPSCO's forward view and driving assumptions, long-term resource requirements and the Short-Term Action Plan summary.

Section 1 - Business Climate: Describes the business climate in which NIPSCO operates and pertinent planning information.

Section 2 - Customer Engagement: Outlines NIPSCO's enhanced customer communications with improved technology, performance measurement and community relations and corporate giving.

Section 3 - Planning Process: Outlines the integrated resource planning process and criteria, and identifies the resource options evaluated for the plan.

Section 4 - Energy and Demand Forecast: Discusses customer electric demand and load characteristics and NIPSCO's customer forecasting methodology.

Section 5 - Existing Resources: Describes NIPSCO's current generating facilities, purchased power agreements, demand-side management programs, and its transmission and distribution system.

Section 6 - Load and Resource Analysis: Evaluates balance between load and existing resources.

Section 7 - Resource Alternatives: Discusses supply and demand-side resource alternatives.

Section 8 - Environmental Considerations: Describes the environmental issues that affect NIPSCO.

Section 9 - Resource Alternatives Analysis: Outlines the integrated resource planning process and potential resource additions.

Section 10 - Transmission and Distribution: Describes NIPSCO's transmission and distribution planning process, criteria, guidelines and assessment for delivering energy services to customers.

Section 11 - 2011 Integrated Resource Plan: Summarizes the long term plan and the actions recommended in the timeframe of 2012 – 2013.

Table of Contents

Appendices Volume I

Appendices Volume II – Confidential

Index of Figures and Tables

INVESTING IN INDIANA'S ENERGY & ECONOMIC FUTURE

NIPSCO

INTEGRATED RESOURCE PLAN EXECUTIVE SUMMARY

INVESTING IN INDIANA

I'm pleased to provide this introduction to NIPSCO's 2011 Integrated Resource Plan (or IRP), a document which I see as a key part of our roadmap to becoming Indiana's premier utility.

Our IRP, presented to the Indiana Utility Regulatory Commission every two years, charts our strategy for meeting the future energy needs of our customers. It outlines our long-term plans to provide cost-effective, reliable and sustainable supplies of electricity to our customers – a service that is essential to powering life in northern Indiana for generations to come.

$5 Billion in System Investments

As you will see, central to NIPSCO's long-term resource plan is our strategy to invest more than $5 billion in system improvements and upgrades over the next 10 years. These investments will not only help ensure reliable service to our customers, but they will also create local jobs and provide a platform for continued economic development across our service territory.

Our system enhancement plans range from approximately $850 million in environmental compliance upgrades to our electric generating stations – projects that will create more than 1,000 jobs – to facility upgrades that will strengthen the reliability of our electric transmission and distribution system.

A Disciplined, Collaborative Approach

As we explore the most cost-effective and reliable energy options available for our customers, we understand there are complex factors affecting the planning process. We consider a wide range of key drivers, such as ever-increasing environmental requirements, an aging electric infrastructure, congestion on the electric grid and the need for service and reliability improvements for our customers. We also incorporate constructive input from many of our key stakeholders, including customers, regulators, industry partners, and the Midwest Independent System Operator.

In developing our analysis, we have kept an open mind, knowing that there is no single approach to addressing all these challenges. For example, rather than adding new and costly electric generating resources, we are

JIMMY STATON
NIPSCO CEO

proposing programs to help customers actually use less energy at critical times, such as new interruptible service options.

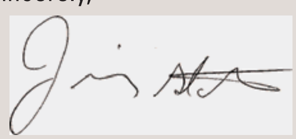
Meeting Customer Needs Now and in the Future

The good news is, our findings indicate that NIPSCO has sufficient existing energy resources – assuming favorable outcomes for pending environmental upgrades – to meet the needs of our customers for the next decade. Our plan also anticipates that NIPSCO will require additional electric generation capacity in 2022. At that point our plan calls for adding an additional clean-burning, natural gas-fired electric generating facility to our energy portfolio.

As you would expect, given the dynamic world in which we operate, our plan is flexible enough to adapt to change. Assumptions about market conditions, fuel prices, energy policies and the state of the economy could change.

We take great pride in our mission to provide Indiana customers with energy that is sustainable, reliable and affordable. We are working hard to meet that commitment now and in the future.

Sincerely,



Jimmy Staton

WHAT IS AN INTEGRATED RESOURCE PLAN

NIPSCO's Integrated Resource Plan is a comprehensive planning document that looks out 20 years to assess customer requirements for electricity and evaluates all our available options to meet that need. Our goal is to reliably and cost-effectively serve customers today and in the future, while addressing the inherent uncertainties and risks that exist in the electric utility industry. The IRP is filed every two years with the Indiana Utility Regulatory Commission (IURC), and it discusses the process, methods, models and assumptions utilized in the plan's development. The strategy includes various studies, analyses and reports generated by a combination of internal and external subject matter experts. The long-term plan may change over time as conditions change and information is updated.

ABOUT NIPSCO

NIPSCO provides affordable, safe and reliable energy to more than 457,000 residential, commercial and industrial electric customers.

Our team of 2,700 employees is dedicated to meeting the needs of this unique and diverse customer base, serving a service territory that spans 21 northern Indiana counties.

We are proud of the significant and positive role NIPSCO plays in enhancing the quality of life in the communities we serve – and where our team members live and work. We are working hard to strengthen customer service and convenience, build strong community partnerships, support economic development efforts, and practice good environmental stewardship.

We believe these efforts serve to strengthen Indiana's economy by improving the quality of life and supporting economic growth and job creation.

These commitments, which are complemented by the long-term planning elements in this IRP, are central to our mission to become Indiana's Premier Utility.

Member of Midwest Independent Transmission System Operators (Midwest ISO)

NIPSCO serves as a member of the MISO network, along with electric utilities across 12 U.S. states and the Canadian province of Manitoba. As a participating member, NIPSCO is able to supplement its existing energy resources with short-term purchases of energy from the markets operated by MISO.

NIPSCO'S CURRENT ELECTRIC PORTFOLIO

In order to cost-effectively and reliably provide electric service to our customers – and to comply with environmental regulations – we must have a diverse portfolio of options.

Coal remains the most common fuel source for generating electricity in the nation. In 2009, 45 percent of the U.S.'s nearly 4 trillion kilowatt-hours (kWh) of electricity used coal as the source of energy (Figure 1).

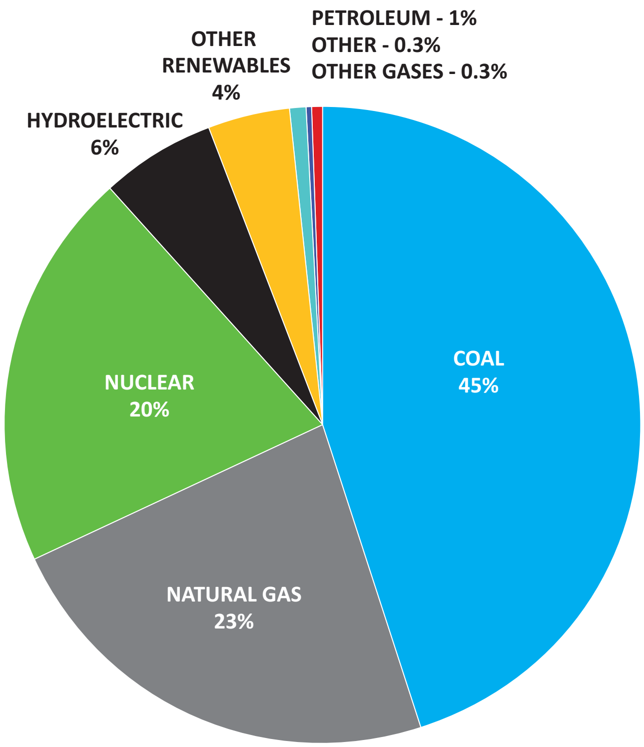
In Indiana, the makeup of coal-fired electric generation accounts for more than 90 percent of the total resources, given the low-cost access and abundant supply of this fuel source within the state.

Up until recent years, nearly 100 percent of NIPSCO electric generating portfolio was comprised of coal-fired generation. Today, our dependence on virtually one fuel source has been greatly reduced (Figure 2).

PRIMARY DRIVERS BEHIND FUTURE ENERGY PLANNING

Once we've obtained an accurate assessment of our customer's future needs for electricity, there are an assortment of key drivers that serve as a guide for how our long-term energy strategy is developed. The following primary drivers are carefully evaluated and factored into the planning process of our Integrated Resource Plan.

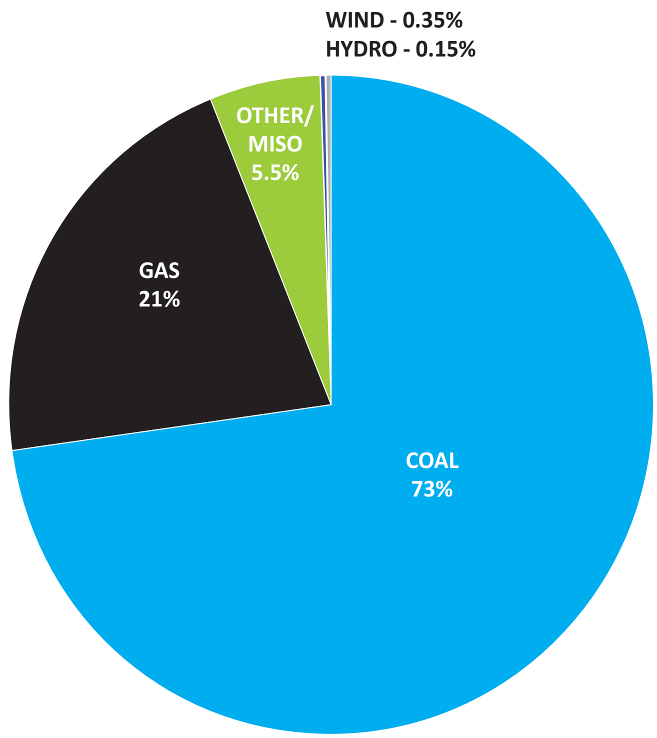
FIGURE 1: U.S. ELECTRIC POWER INDUSTRY NET GENERATION BY FUEL, 2009*



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION, ELECTRIC POWER MONTHLY, TABLE 1.1 (MARCH 2011), PRELIMINARY DATA

** For illustrative purposes only.*

FIGURE 2: NIPSCO NET ELECTRIC GENERATION BY FUEL



Customer Demand

The ability to forecast future electric demand is challenging, given the spectrum of unforeseen variables – primarily externally-driven – that can alter our outlook.

Our forecasts show an increase in overall customer demand by about 20 percent over the next 20 years. The total number of NIPSCO electric customers is projected to increase from approximately 457,000 customers today to about 506,000 customers by 2032.

Accurate forecasting also applies to Indiana's manufacturing sector, which has a large concentration in the northern part of the state. Approximately 26 percent of the nation's steelmaking industry capacity resides in NIPSCO's service area.

Considering the steel industry's global nature, the number of variables that can affect the economic condition of the industry is extensive. The ability to accurately forecast future economic activity within this sector becomes increasingly important to effectively plan for future energy resource needs.

Reliable Energy

In the age of electronics and emerging technologies, the need for a constant, reliable source of electricity has grown. Customers' tolerance for an interruption has diminished.

While renewable energy resources provide a significant environmental benefit, they lack the same level of reliability offered by other options such as natural gas or coal-fired generation. Until renewable energy has the ability to be stored for an extended period of time, it will continue to serve as a supplemental supply of power, rather than a base-load source.

Affordable Energy

Historically, coal-fired electric generation has served as the least expensive option for generating electricity. Coal is also an abundant natural resource – particularly in Indiana.

However, the projected cost for natural gas – as a result of the prolific shale gas discoveries in North America, a robust long-term supply outlook, and stabilized prices – has quickly cut the gap in terms of its price relative to coal-fired market prices.

We also recognize the relative drop in prices for renewable energy resources as the market continues to develop, and we are encouraging renewable energy development through our net-metering and feed-in tariff customer programs.

Environmental Regulations

Protecting the environment is important. The U.S. Environmental Protection Agency (EPA) continues to present new regulations seeking improvements in air and water quality, coal ash management and more. With more stringent regulations comes increased compliance costs which must be passed on to customers in their electric bills.

NIPSCO has a proven track record when it comes to meeting or exceeding environmental standards, and we also recognize we must remain focused on maintaining a balance between the financial impact to customers and environmental progress.

Aging Infrastructure

The average age of NIPSCO's current electric fleet is more than 40 years, which is comparable to facilities across the nation.

As a result of increased environmental regulations, we expect to see a rise in the retirement of smaller and older electric generating facilities within the MISO footprint.

Our long-term strategy, however, includes the continued investments and necessary environmental upgrades to keep our facilities running efficiently for years to come.

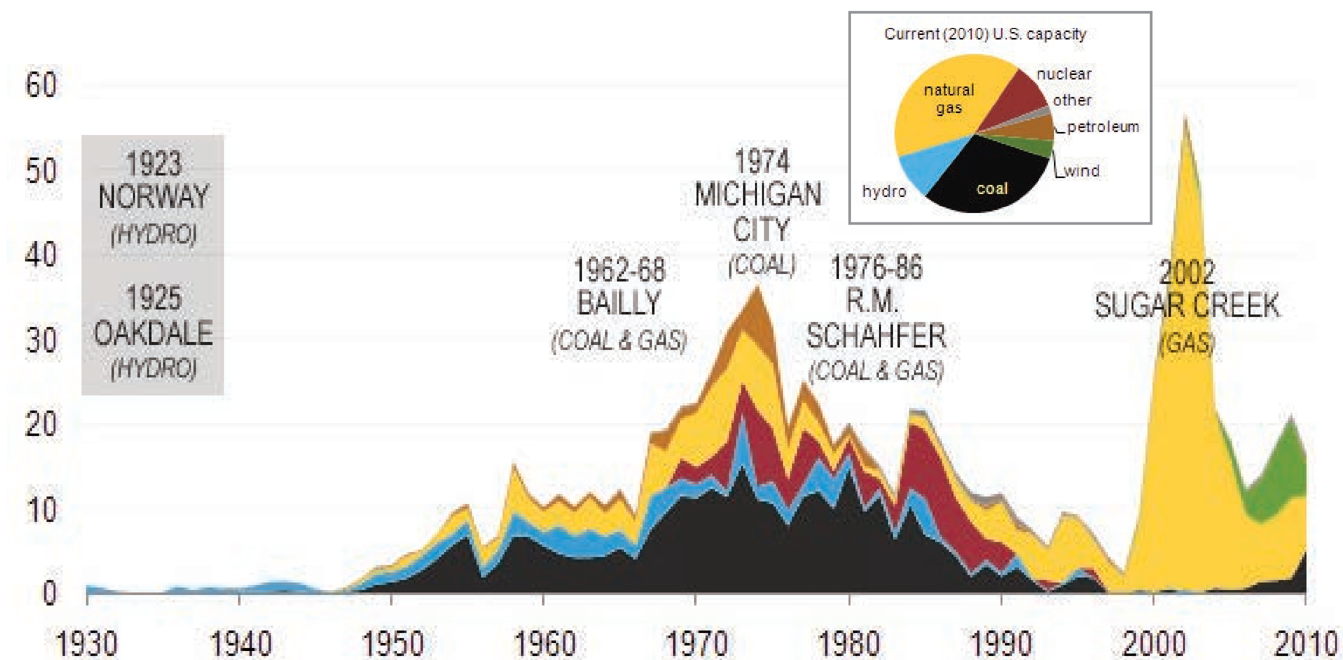
MODERNIZING THE
ENERGY DELIVERY SYSTEM

A reliable source of energy begins with a modern, up-to-date energy infrastructure. And, just like the nation's plans for improving its transportation infrastructure, the utility industry is in need of an overhaul to ensure that it has a safe and reliable system to keep up with future demand.

Not only is NIPSCO in the process of upgrading our existing electric generating facilities to meet new environmental requirements, we are also making the necessary investments to strengthen our electric transmission and distribution system to improve the safety and reliability of our service.

These improvements will provide greater market access to supplies of electricity at lower costs, as well as improved service to our customers.

CURRENT (2010) CAPACITY BY INITIAL YEAR OF OPERATION AND FUEL TYPE - GIGAWATTS*
INCLUDING NIPSCO START-UP DATES OF ACTIVE UNITS



SOURCE: WWW.EIA.GOV
** For illustrative purposes only.*

EVALUATING ALL AVAILABLE OPTIONS

Each source of electric generating options comes with its own set of unique advantages and disadvantages, ranging from relative costs and environmental benefits to reliability and impact on the electric system. As we prepare our 2011 Integrated Resource Plan, we conducted a thorough evaluation of the following options to meeting our customers' future energy needs:

- Coal-Fired Electricity
- Natural Gas
- Renewable Energy
- Hydroelectric Power
- Biomass Energy
- Nuclear
- Energy Efficiency
- Interruptible Service
- Customer-Generated Power

Ultimately, our electric portfolio strives to include a diverse mix of options that provide the most cost-effective, sustainable and reliable source of energy for our customers.

Energy Spotlight: Customer-Generated Power

We offer two program options aimed at promoting further renewable generation opportunities in northern Indiana and responding to customers' interest in powering their homes and businesses with renewable energy projects.

The program options – Net Metering and Feed-in Tariff – allow customers to either sell the energy they generate back to us or offset their own usage. The added power is then used by other NIPSCO electric customers.

In addition to contributing to environmental sustainability, these programs help slow the need for us to invest in additional power resources, as the demand for energy continues to rise.

SHORT-TERM ACTION PLAN BASED ON FINDINGS

In summary, our findings indicate that we will utilize our current electric portfolio in 2012 and 2013, combined with the availability of interruptible resources and market purchase of short-term electric capacity as needed to meet reserve requirements and customer demand.

LONG-TERM PLAN FOR FUTURE ENERGY NEEDS

Compared to the last Integrated Resource Plan filed two years ago, the 2011 IRP preferred portfolio reflects:

1. Increased energy efficiency and demand side management resources
2. Increased market purchases
3. Potential new gas-fired combined cycle gas turbine (CCGT) generation
4. Potential retirement of 528 MW of primarily coal-fired generation and expiration of 100 MW of wind generation PPAs

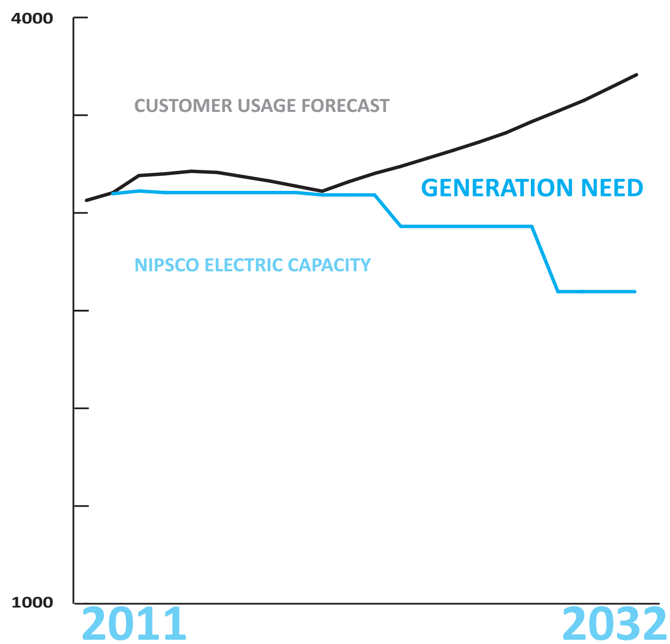
NIPSCO's current generation – incorporating required environmental controls – are projected to operate through the period up to 2022. Between 2013-2022, we plan to meet projected energy needs by calling on additional interruptible service. If such resources do not meet our estimates or are not available, we will supplement our capacity needs with market power purchases.

In 2023, we are projecting the need for a CCGT facility. The construction lead time for a CCGT facility is five years, which requires approval from the Indiana Utility Regulatory Commission.

We will continue to monitor market conditions and revisit the supply-side resource plan in our 2013 IRP, and we expect to conduct a Request for Proposal for CCGT facilities to support the analysis of market options in its 2013 IRP.

The long-term plan is subject to change. Factors that can affect the plan include capital investments, revised assumptions, the retirement of aging units, policy, legislative and regulatory changes, market opportunities and economic changes. We continue to evaluate potential options for our long-term energy resource plan as appropriate to ensure that the best decisions are made for serving customers now and in the future.

NIPSCO FORECAST GENERATION NEED - MEGAWATTS



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SECTION 1: BUSINESS CLIMATE

NIPSCO

INTEGRATED RESOURCE PLAN

Highlights – NIPSCO's Business Climate

- ***NIPSCO's customer base is unique, with a heavy industrial concentration.***
- ***A significant percentage of residential customers (about 12 percent) is economically challenged.***
- ***NIPSCO's economic development activity serves to strengthen Indiana's economy by supporting growth and creating jobs.***

NIPSCO provides electrical service to more than 457,000 commercial, industrial and residential customers in 20 counties in the northern third of Indiana. Its electric service territory contains the industrial cities in Lake and Porter counties of Crown Point, East Chicago, Gary, Hammond, Michigan City and Valparaiso, and other cities and towns across Northern Indiana including Angola, Goshen, LaPorte, Monticello, Plymouth and Warsaw.

Unique Customer Base

The diversity of NIPSCO's customer base is equal to the unique diversity of the Hoosier state. NIPSCO's customer base includes very large industrial customers, various large, medium and small commercial and business customers, and more than 375,000 residential customers located in urban, suburban and rural settings. Each customer group has its own set of specific attributes and issues, which provides NIPSCO with its unique customer profile and some of the special issues that go with it.

Some Key Statistics about NIPSCO's Territory

- More than 90 percent of NIPSCO's customer base resides in three areas: Chicago Metro (Lake, Porter, Newton and Jasper Counties), La Porte County (including Michigan City) and the Elkhart/Goshen area.
- 376,000 households, about 1 million residents, live in these three areas.
The balance of served households is widely dispersed throughout the service territory.
- This region has approximately 84,000 manufacturing jobs, nearly 1 in 4 households.
- The August 2011 unemployment rate in NIPSCO's territory was 9.6%, versus a statewide rate of 8.7%.

As such, NIPSCO is working to achieve a balance to meet the needs of all of its customers when it develops and proposes solutions to issues facing the businesses and residents of Northern Indiana – such as strong impact global market forces can have on our largest customers and the trickle-down effect their performance can have on other businesses and workers in the region.

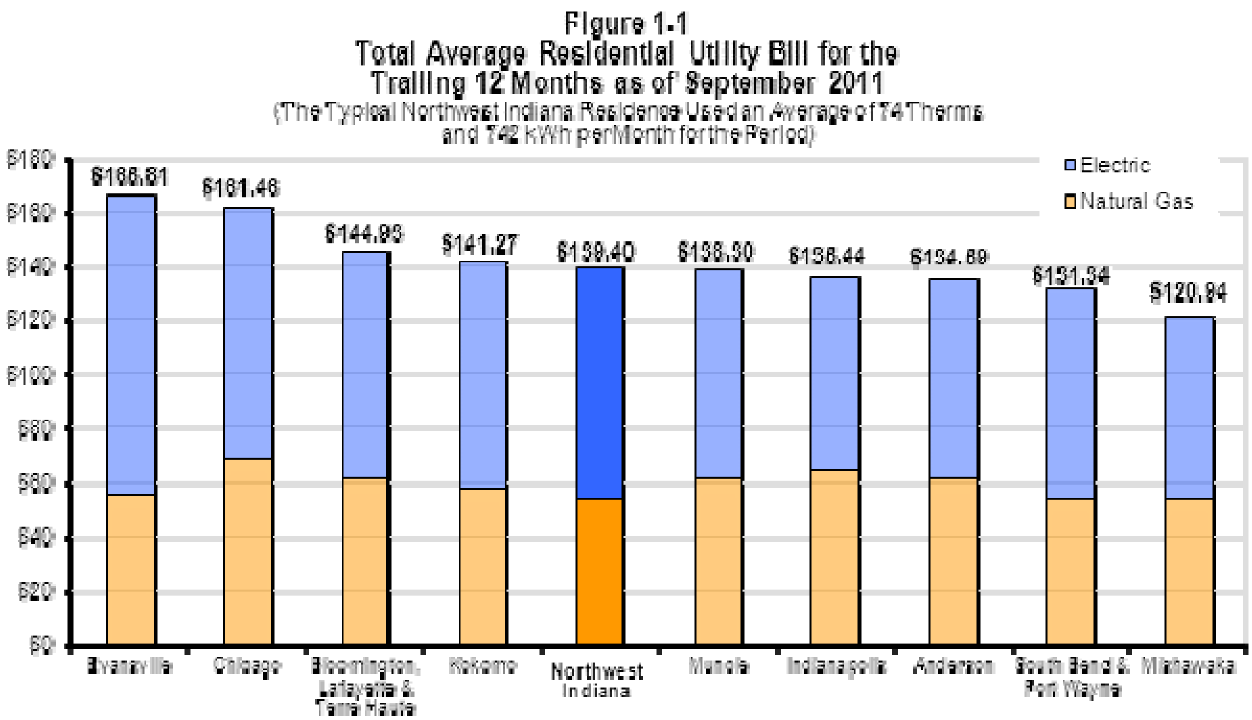
Unique Customer Challenges

Industrial customers, primarily in steel and oil refining, account for less than 1 percent of NIPSCO's total customers. These customers, however, make up more than 50 percent of NIPSCO's total energy sales and are among the top production facilities in the United States. These industries have been a mainstay of Northwest Indiana since the late 1800's and require unique energy services. While operations consume large amounts of energy, at times consumption can vary widely on short notice. These industries follow economic cycles and are tied to the global economy. As such, NIPSCO's planning assumptions are heavily dependent on its ability to accurately forecast future economic activity.

Other unique customer considerations include the demographics of our service territory. Some residential customers are challenged by the economy and face economic hardships that affect their ability to pay for electric and other utility services. At this time, approximately 12 percent of the population in NIPSCO's electric service territory lives in poverty.

Serving a Unique Customer Base

NIPSCO's combined utility offering is extremely competitive in Indiana as shown in Figure 1-1. NIPSCO continually works to keep prices as low as possible for all customers.



- Indiana Natural Gas pricing data from IURC
- Indiana Electric pricing data from utility tariff available at utility web-site
- Chicago pricing data from ComEd & People's NG, tariff available at utility web-site
- Usage data from NIPSCO Customer Information System

For example, interruptible rate tariffs, which allow NIPSCO to reduce electric demand during peak and expensive time periods, are a least cost solution that is a benefit for all customers. NIPSCO is actively working with its largest customers to implement interruptible services, which will assist these customers in managing their overall energy costs. Lower utility costs help energy intensive industries maintain overall cost competitiveness, keeping businesses and jobs in Northern Indiana. Other customers benefit as well when mainstay economic activity is maintained and when additional generation investment is deferred. The settlement reached in the pending electric rate case provides for up to 500 MW of interruptible service, which is roughly equivalent to a new combined cycle gas turbine ("CCGT") with a cost approaching $500 million. This creative regulatory approach minimizes costs for all customers.

Environmental Compliance Plan Considers Customer Base

Compliance with environmental regulations impacts our customers in two ways. First, a large portion of the next decade's increases in electric costs are anticipated to be driven by environmental compliance investments. Second, our large industrial customers will require investments to make their operations environmentally compliant. Absent significant adverse changes, NIPSCO's compliance strategy, supported by current regulatory proceedings, entails the environmental retrofit of existing power plants, maintaining the generation fleet's tradition of full environmental compliance. The 2011 IRP presumes a favorable ruling in the regulatory compliance filing proceedings, allowing NIPSCO to construct Flue Gas Desulfurization ("FGD") for R.M. Schahfer Units 14 and 15 and Michigan City Generating Station Unit 12. Based on recent stakeholder feedback, additional analysis regarding Unit 12 FGD will be provided. NIPSCO anticipates spending more than $600 million through 2018 so existing units will meet environmental obligations. NIPSCO undertakes these environmental investments only after diligence; ensuring our strategy is a least cost solution for our customers. NIPSCO will to continue to assess other resource options.

Economic Development

NIPSCO is pleased to join other leaders at the state and local level in working to build our economy. These efforts include partnering to attract new investment; new jobs, streamlining the process for companies moving to the area, and helping existing businesses expand. In addition, NIPSCO's Economic Development Rider tariff offers discounts on existing tariff services for qualifying economic development projects that bring in new jobs and investment from outside the territory. When coupled with local and state incentives, a powerful package is created with often positive results.

NIPSCO's resource plans focus on maintaining and developing resources in NIPSCO's service territory. NIPSCO's transmission and distribution system is designed to provide all customers with reliable energy services. For NIPSCO facility construction, NIPSCO has a focused effort, tapping local, Indiana-based resources first as it relates to building and construction support, supplies and other specialized service needs.

Legislative Solutions

Legislative solutions may be part of the answer in helping to balance stakeholder interests especially for low income customers' affordability issues. Legislative solutions may also be part of the answer for addressing energy service providers' infrastructure investment issues.

2011

SECTION 2:
CUSTOMER ENGAGEMENT

INTEGRATED RESOURCE PLAN

Highlights – NIPSCO's Customer Engagement

- ***Technology enables better customer communications and improved control of Transmission and Distribution ("T&D") assets.***
- ***Listening to customers helps formulate creative solutions to meet their needs.***
- ***NIPSCO gives back to, and supports local communities.***

Improving Customer Engagement

NIPSCO is working hard to improve relationships with our customers and the communities we serve in Northern Indiana. Customers benefit from our renewed focus on customer service, community partnerships, economic development, environmental stewardship and corporate citizenship, which has served to strengthen Indiana's economy by supporting growth and job creation. NIPSCO is also striving to enhance the customer experience by offering customers new and convenient ways to conduct business.

Communicating with Customers

The recent electric rate case settlement process and Demand-Side Management ("DSM") proceedings are examples of successful communications between stakeholders through a formalized process. Stakeholders established common ground, and then collaboratively worked to resolve differences as part of the process.

Fostering Community Partnerships - Community Advisory Panels ("CAPs")

NIPSCO uses CAPs as an outreach avenue with our stakeholders and customers. The CAPs serve as a positive forum to discuss new company initiatives and programs as well as to facilitate feedback regarding service and other NIPSCO-related matters in their communities. NIPSCO has established six regional across the Company's footprint; which are comprised of customers, local government and community leaders representing a broad cross-section of NIPSCO customers. NIPSCO senior management meets with each of the regional CAPs three times annually to share the company's strategic direction and to ask CAPs members for their insights on emerging issues.

Community Support

Supporting Job Growth and Economic Development

NIPSCO is a leader in driving local and statewide economic development opportunities and invests more than $1 million annually on economic development initiatives. Through established partnerships with local communities, the State, and regional economic development organizations across its service territory, NIPSCO has successfully helped communities grow by attracting new jobs, streamlining the process for companies moving to the area, and helping existing businesses expand; and will continue to do so in the future. In recent months, qualifying business expansions for two companies resulted in the creation of nearly 500 jobs. NIPSCO also has a focused effort on tapping local, Indiana-based resources first as it relates to building and construction support, supplies and other specialized service needs.

Corporate Citizenship

Recognizing the importance of being a good corporate citizen, NIPSCO invests more than $1.5 million annually to support local organizations and efforts that help improve the overall quality of life across the service area.

- In September 2011, NIPSCO, NiSource, its employees, vendors, family and friends contributed $200,000 to the American Heart Association ("AHA"). This contribution is among the largest in the nation for AHA this year.
- Additionally, NIPSCO employees at all levels of the organization actively volunteer their time and effort within local communities. Many employees take leadership positions on local boards that help drive economic development, support those in need and make Northern Indiana a better place to live.
- As an example of NIPSCO's commitment to the growth of its service territory, NIPSCO has partnered with the Urban League to introduce a pilot mentoring program where students from selected local schools will meet with NIPSCO volunteer mentors to discuss and learn about the utility business. NIPSCO has also partnered with Ivy Tech to provide training classes to those students who wish to explore a career in the utility industry.
- NIPSCO implemented a Disaster Recovery team. NIPSCO employees will be on site after severe weather to help customers with basic necessities, aid in service restoration, and answer questions. NIPSCO seeks to expand its personal outreach to all of its customers.
- NIPSCO participates in community events and festivals throughout the service territory. NIPSCO representatives attended many county and city events in 2011, promoting new energy efficiency programs and convenient access to Company representatives to ask questions and to provide feedback and suggestions.

Delivering Outstanding Customer Service

Through customer input, learning from top-performing utilities in the customer service category and other research efforts, NIPSCO has forged a strong commitment to improving service to its customers. NIPSCO strives to be a trusted energy adviser for customers, while developing more convenient options to manage bills, receive helpful information and conduct business. The Company has also been focused on providing more convenient ways for customers to connect with the Company through the web, enhancements to our Interactive Voice Response ("IVR") system, and a mobile platform whereby customers will be able to view and pay their bills, report gas leaks, and power outages all through their mobile phone. NIPSCO currently has the lowest level of justified complaints among the large utilities in Indiana and ranks in the first or second quartile of utilities across North America with regards to Average Speed of Answer and Abandonment Rate.

Surveys

Customer feedback drives all we do in customer support and customer service offerings. Currently, NIPSCO surveys customers to measure customer satisfaction with the call center, the IVR, and the interactions with field personnel. Customer surveys are also used to capture specific customer issues, and to get immediate feedback on the quality of customer service. NIPSCO uses the results of these surveys, as well as JD Power Surveys to identify ways to improve customer interaction processes, to improve customer service representative ("CSR") training and development, and to improve the use of technology to better the overall customer experience.

Customer Support and Customer Service Offerings

Service Enhancements

Call Center and New Offerings

NIPSCO continues to upgrade its call center technology for more effective customer service. The IVR menu was simplified to make it easier for customers to conduct business. A new CSR dashboard is being implemented to give CSRs the ability to monitor their effectiveness on a real time basis.

Ambassador Program/Customer Point of Contact

The Ambassador Program, introduced in 2009, enables all NIPSCO employees to be ambassadors to customers. This provides customers with another means of resolving open questions and issues. NIPSCO established an internal process to receive customers issues through employees creating a culture focused on customer service throughout the organization.

Voice of Customer Process

NIPSCO created a new Customer Care Advisor position in 2010. This position tracks customer feedback channels and performs trending analysis. The Customer Care Advisor recommends customer communications improvements and customer service and field training enhancements.

New Gary Business Office

NIPSCO relocated its Gary Business office in February of 2011. Centrally located in Gary, the new location provides easier access for customers. The new office is larger to serve more customers and is used as a disaster recovery site for the main call center in the event of an emergency.

Builder/Developer Web Portal

Working with the builder/developer community, NIPSCO created an informational and transactional builder/developer portal on www.nipsco.com. Builders and developers can request utility service and access information including job site preparation and Gas & Electric Standards.

Demand Response Tariff

Working with industrial customers, potential customer aggregators, and other Indiana utilities, NIPSCO developed demand response curtailment options for individual customers and aggregated customers pools. Participants can elect to be curtailed during high electric load periods in return for financial rebates.

Pilot Programs for System Improvements and New Customer Services

System Operations

Working with MISO on several new technology initiatives for system reliability and quality, NIPSCO is installing synchrophasor devices on its transmission system. These Phasor Measurement Units provide MISO and NIPSCO with wide-area electrical measurements that monitor overall system operation and reliability. NIPSCO is participating in the Frequency Monitoring Network, a network of frequency tracking devices spanning North America. NIPSCO installed its first frequency data recorder in 2010, and a second in 2011. MISO is coordinating both projects, with the majority of the costs reimbursed through the DOE Smart Grid Investment Grant.

Feed-in Tariff

NIPSCO offers a feed-in program option aimed at promoting further renewable generation opportunities in Northern Indiana and responding to customers' interest in powering their homes and businesses with renewable energy projects. NIPSCO collaborated with the Indiana Office of Utility Consumer Counselor, the Hoosier Chapter of the Sierra Club, Citizen's Action Coalition, Indiana Distributed Energy Advocates and Bio Town Ag regarding the expansion of the company's ability to acquire or purchase customer-generated electricity from renewable energy.

The feed-in tariff allows small independent power producers of renewable energy, and residential customers with renewable energy resources, to offset their electric consumption costs by selling to NIPSCO power generated via these renewable resources. It allows NIPSCO access to a diverse mix of small capacity renewable resources to include new wind, solar, biomass, and hydroelectric technologies, in addition to contributing to environmental sustainability.

Electric Vehicle Tariff

NIPSCO is working with various stakeholders towards approval of an Economic Development Program that promotes the deployment of alternative fuel vehicles.

Customer Service Technology Upgrades

NIPSCO is improving customer support through technology upgrades and improvements. The following items represent technology upgrades or improvements that were completed since the last IRP submission and facilitate the improvement of service to our customers:

2009 (post 2009 IRP Filing)

- AllConnect integrates customer account detail and new service eligibility to enhance call center responsiveness and to help achieve first call resolution

2010

- Newly upgraded, user friendly NIPSCO website
- Web enhancements for new gas Choice Marketers Program
- Upgraded central cash/teller cash systems
- Web self-service enhancements
- Customer outage communications provide outage information and restoration times
- Opower integration provides customers with information to help reduce energy usage and take advantage of efficiency options
- Streetlight outage web reporting
- Call Center upgrade enhanced stability of call center technology to support CSR

2011

- Field control system for new meter data collection system

- Integrated computerized systems for work management
- Corrective Action Program software implementation to manage process improvements
- Mobile web self-service transactions and information via mobile devices

SECTION 3: PLANNING PROCESS

NIPSCO

Highlights – Planning Process

- ***The goal of NIPSCO's 2011 IRP is to identify resource options that reliably and cost-effectively meet customers' future energy needs.***
- ***Internal and external experts identified key assumptions, including operating parameters, customer needs, resource technologies, environmental regulations, economic conditions, and commodity markets.***

Planning is part of NIPSCO's ongoing business process. NIPSCO's 2011 IRP reflects the Company's long-term plan based on information available at the time.

Description of the IRP Process

NIPSCO developed its 2011 IRP by modeling projected customer electric load and the resource options that could be used to meet that load. The goal is to develop a long-term strategic plan that ensures NIPSCO will continue to provide reliable, reasonable-cost service to its customers.

The long-term strategic plan identifies customer and resource needs over a 20-year planning horizon, and recommends a potential resource portfolio to meet customer needs. A Short-Term Action Plan identifies the steps the Company will take during 2012 and 2013 to implement the strategic plan. The plan provides for compliance with applicable mandates and policies, and uses a balanced approach to manage cost, risk, uncertainty and reliability elements.

Creating NIPSCO's 2011 IRP was an iterative process. NIPSCO used both internal and external resources to accomplish the tasks necessary to complete the process. These tasks included:

- Collecting data needed for the planning process, including operating parameters, customer demand forecast, resource technologies, environmental compliance plan, economic conditions, and commodity markets;
- Identifying demand-side and supply-side resource options (market-based, self-build and renewable) resources;
- Evaluating resources, considering environmental externalities; and
- Selecting the best options to create an integrated, effective, and responsive plan.

NIPSCO conducted uncertainty, or sensitivity, analyses for different economic and environmental circumstances. NIPSCO recognizes that such events are often difficult to predict with accuracy. Based on the uncertainty analyses, the 2011 IRP addresses the most likely contingencies. The options were integrated resulting in the optimal long-term plan. The Short-Term Action Plan was developed to identify implementation steps in the first two years. After developing the Short-Term Action Plan, NIPSCO continued the planning process, by monitoring changes in elements of the plan.

In summary, the 2011 IRP process takes a myriad of resource options through various screening and detailed analyses. The process methodically funnels down the resource options until a combination of feasible and economic resource options are reached. This combination of resources reliably meets the anticipated future customer needs, at the lowest reasonable cost and maintains flexibility. NIPSCO's planning process is part of the ongoing business process. New information is analyzed as it becomes available.

The NIPSCO IRP Team consisted of experts from key functional areas within NIPSCO and its affiliate NiSource Corporate Services Company. Additionally, the following energy and engineering consultants listed below provided input to the development of the 2011 IRP:

- Burns & McDonnell 400 Ward Parkway, Kansas City, Missouri 64114
  performed the engineering study
- Ventyx, L.L.C. - 3301 Windy Ridge Parkway, Suite 200, Atlanta, Georgia 30339
  provided consulting services for the IRP preparation and evaluation
- IHS Global Insight - 24 Hartwell Avenue, Lexington, Massachusetts 02421
  provided forecasts of independent variables for NIPSCO's load forecasting process
- James Marchetti, Inc. - P.O. Box 36, Great Barrington, MA 01230
  provided the Environmental Compliance Planning assistance
- PIRA Energy Group - 3 Park Avenue, 26th Floor, New York, NY 10016
  provided the environmental assumptions for NO_x, SO_2 and CO_2
- Telvent DTN, Inc. – 9110 West Dodge Road, Omaha, NE 68114
  provided hourly weather data for three weather stations
- Morgan Marketing Partners - 6205 Davenport Drive, Madison, Wisconsin 53711
  provided assistance with modeling DSM programs in DSMore™
- Itron, Inc. - 2111 North Molter Road, Liberty Lake, Washington 99019
  provided historical and forecasted end use data

2011 Enhancements to the IRP Process

Dispatch to MISO Market Modeling

In previous IRP filings, NIPSCO employed a traditional utility "hub and spoke" interchange model. This traditional interchange model commits and dispatches NIPSCO units to meet NIPSCO load. Post unit commitment, the traditional interchange model evaluates the NIPSCO system marginal cost against the market price. When the external energy market price is less than NIPSCO's system marginal cost, and operational constraints permit it, uneconomic generation is backed down and replaced by economy energy purchases from the off-system market. When the external market price is greater than NIPSCO's system marginal cost and operational constraints permit it, available economic units are dispatched and sold into the off-system economy energy market. NIPSCO compared actual historical off-system sales to predicted off-system sales and benchmarked their production cost models to achieve equivalent sales.

The current MISO market structure is very different from the traditional utility interchange market model. Under the current MISO market structure, MISO administers an organized central market for wholesale power. Market participants, such as NIPSCO, may sell generation into the MISO market based on resource offers that include operational limits and an offer curve. MISO uses a security constrained economic dispatch to clear the forward energy market. The dispatch ensures adequate resources are available to meet the Day-Ahead energy market, and manage congestion. The result is an individual Locational Marginal Price ("LMP") for each generator and load hub. For the purpose of long term planning, NIPSCO addresses the Day-Ahead energy market and does not attempt any representation of the Real-Time energy market. MISO's market settlement consists of all generators selling to MISO at the generator's hub LMP and purchasing all loads from MISO at the load hub LMP.

DSM Energy Savings Incorporated into the Energy and Demand Forecast

NIPSCO anticipates compliance with the Commission's generic DSM order in Cause No. 43693, Phase II, calling for implementation of a portfolio of Core DSM programs on a statewide basis and targeting energy savings of 2 percent by 2019. NIPSCO has incorporated energy savings into its Energy and Demand Forecast.

2011

SECTION 4:
ENERGY AND DEMAND FORECAST
2012-2032

NIPSCO

INTEGRATED RESOURCE PLAN

Highlights – Energy and Demand Forecast

- ***NIPSCO expects energy consumption will grow at a rate of less than 1 percent annually over the next 20 years.***
- ***Low growth in the industrial segment is attributed to implementation of energy efficiency measures***
- ***NIPSCO's implementation of energy efficiency programs helps to manage growth without additional resources until 2023.***
- ***Peak demand is expected to grow from 3,127 MW in 2011 to 3,796 MW by 2032.***

Based on its analysis of the electric marketplace in Northern Indiana for the current IRP timeframe, NIPSCO is projecting low growth rates for electric demand of less than 1 percent annually through 2032.

Discussion of Load

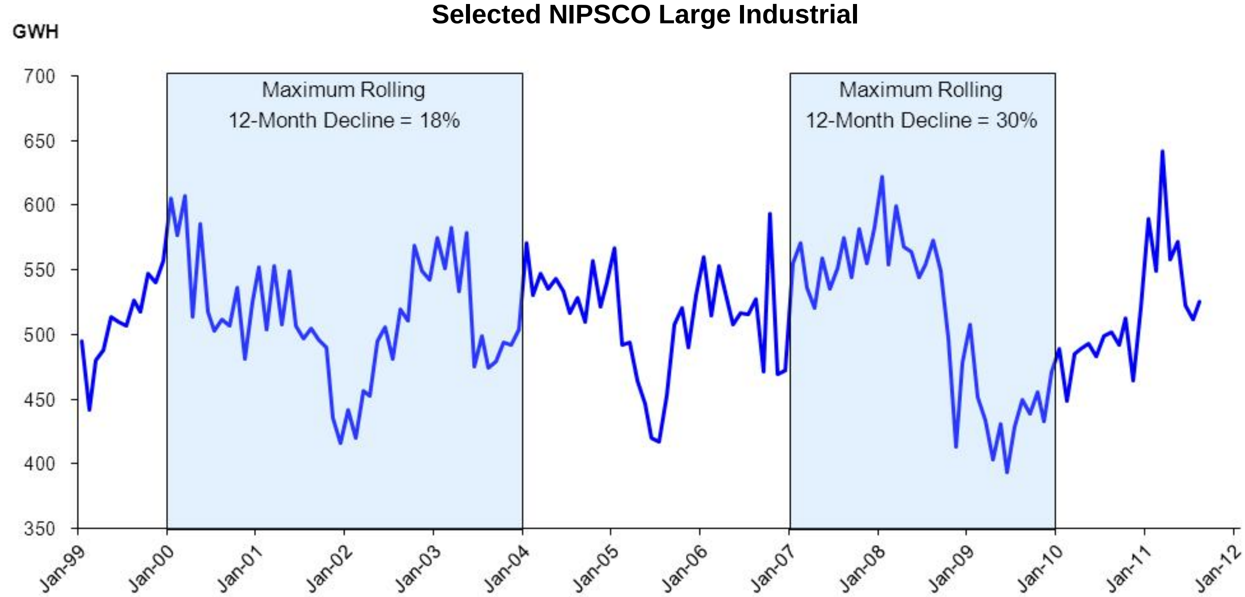
NIPSCO has a high proportion of manufacturing and industrial load on its system that affects both demand and resource planning. This load is highly variable and can be difficult to forecast. Understanding the demand characteristics of NIPSCO’s customers is important to establishing the demand and energy forecast.

Uncertainty of Industrial Demand

Approximately 50 percent of NIPSCO’s sales are attributed to the total industrial class. NIPSCO’s industrial load creates complexity in forecasting electric demand. Because the level of industrial consumption on NIPSCO’s system is greater than all other rate classes, industrial loads are capable of creating swings in demand throughout any given hour, day or week. Industrial consumption (primarily steel manufacturing) is generally not weather sensitive, but rather is more likely to be responsive to business cycles and trends. Individual operations inside our customers’ mills can swing load by more than 80 MW almost instantly. Industrial consumption is highly dependent upon transmission, distribution and energy delivery reliability. That is, industrial loads often rely on equipment that is sensitive to voltage fluctuation or that requires considerable electricity flow to restart after maintenance or shut-down.

There are several key characteristics underlying NIPSCO’s industrial forecast. First, volatility of the industrial load is capable of impacting the demand forecast because large industrial users can vary consumption by 20% or more within a one-hour period, depending on operating schedules, production upsets, and equipment availability. If industrial users use less or more than predicted, or operate with more load swings, the forecast may not be representative of future actual events. Second, if one large industrial customer severely downsizes or shutters its operations, the magnitude of the potential revenue loss relative to NIPSCO’s entire revenue requirement is such that making up the shortfall may be difficult. Three steel manufacturing customers drive almost all of our steel related energy demand. This concentration is a challenge unique to NIPSCO among Indiana utilities. Third, steel production levels vary. In the recession of 2007-2010 (see Figure 4-1), steel industry energy consumption dropped over 30%. Fourth, the future of carbon or Green House Gases (“GHG”) regulation is uncertain.

Figure 4-1
Selected NIPSCO Large Industrial



Introduction of DSM

NIPSCO's forecast includes projected results from the implementation of DSM programs, approved in Cause No. 43618 and implemented in January 2011. Details of NIPSCO's DSM program are covered later in this document.

Methodology

The 2011 IRP electric energy and peak demand forecast model uses an econometric approach to forecast long-term electric energy sales and peak hour demands. The forecast employs data representing service area demographics and economic data, saturation and efficiency information, electric energy sales by class, price of energy, and average monthly and peak hour weather. Residential consumption is related to end uses and efficiencies and real per capita income. Commercial activity is captured with gross county product. Prices for typical electric bills are used in both the residential and commercial econometric models to measure customer behavior in reaction to changing price.

In creating the NIPSCO Forecast for the 2011 IRP, individual forecast models were developed and validated for: residential sales; commercial sales; industrial sales; street lighting sale; public authority sales; railroad sales; company use sales; and 60-Minute electric peak demand.

Description of Sales Forecast Models

Residential Sales Forecast Model is calculated using a residential customer model and an average residential use per customer model. Average residential use per customer projections are multiplied by the total residential customer forecast to generate the total residential sales forecast. The residential use per customer model is a function of appliance saturations and efficiencies as defined in an end use variable supplied by Itron, Inc., real per capita income, and the real price of electricity. Other forecast considerations integrated into the residential sales forecast model are residential customer counts, cooling degree days ("CDD") and heating degree days ("HDD"). The residential customer count is a function of a three year outlook for new construction provided by NIPSCO's new business team and is developed using a "grass roots" approach. This grass roots approach includes conducting interviews with real estate developers and builders; thus assuring that short-term housing market intelligence is included in the forecast. The longer term customer outlook is modeled as a function of housing starts and is adjusted for customer attrition applied at an average historic rate. Total residential customers are calculated by incorporating the new customer outlook, existing customers and the historic attrition rate.

Commercial Sales Forecast Model is estimated using a total commercial energy usage model. Commercial energy consumption is a function of the commercial customer count, real gross county product, energy price, CDD and HDD. As with residential, the initial three year outlook for commercial customers is provided by NIPSCO's new business team. The longer term view is modeled as a function of local population and total employment. The commercial customer count forecast also reflects a historical attrition rate.

Industrial Sales Forecast Model forecasts the expected level of industrial sales in NIPSCO's service territory. Accordingly, the industrial sales forecast model contains individual sales forecasts for the largest of the Major Industrial account customers.

To obtain information specifically relevant to the creation of the industrial sales forecast, NIPSCO makes individual contact with each of its Major Industrial account customers and discusses each customer'' individual business, economic and strategic objectives. The goals, plans and concerns espoused in these one-on-one discussions form the basis of a forecast recommendation for each customer. The interviews are then combined and incorporated into a forecast model utilizing the Industrial Production Index (Primary Metals) growth curve to current run rates. The resulting forecast for the group, referred to as "Major Industrial," includes details concerning the outlook held for steel producers and related industries in Northwest Indiana. Importantly for the development of the NIPSCO Forecast for the 2011 IRP, this survey integrates the actual economic and business forecast of the customer with that customer's consumption related to each of its major industrial production sites in NIPSCO's service territory.

The industrial sales forecast model also integrates a sales forecast for the remaining industrial accounts (identified as "Other Industrial"). The Other Industrial sales forecast includes forecast data of national and state production indexes taken from IHS Global Insight. The Other Industrial forecasted growth curve also reflects the Industrial Production Index (Primary Metals) annual increases built at current usage levels.

Street-Lighting, Public Authority, Railroads, Company Use and Losses forecast is based upon units in service and known or anticipated trends.

60-Minute Electric Peak Demand Model calculates with a regression model using energy sales by class, cooling degree hours (summer) or heating degree hours (winter) at peak hour, and relative humidity at peak hour.

Customer Self-Generation
Most of NIPSCO's large electric customers with self-generation utilize the generation as a by-product of process steam production needs. The generation is not predictable or dispatchable to the utility.

Data Source – Internal is data collected internally by the Company in its regular business activities pertaining to energy sales, demands, number of customers, and price and saturation levels for the forecasting process. NIPSCO collects internal peak hour MW for the control area, wholesale customers, eight large industrial customers and all other. Both firm and interruptible MW are collected.

NIPSCO produces historical estimates of weather-normalized energy. Because industrial class energy consumption varies very little with weather, the Company weather-normalizes kilowatt hour ("kWh") sales for the residential and commercial classes only. The normalization procedure uses coefficients obtained from regressions of 36 months of kWh/Customer on CDD and HDD.

The general normalization equation is:

Normal kWh/Customer = Actual kWh/Customer + ((CDD coefficient) * (Normal CDD – Actual CDD)) + (HDD coefficient * (Normal HDD – Actual HDD))
Where
Monthly Normal kWh = (Normal kWh/Customer * Customers) and
Annual Normal kWh is the sum of the monthly normal kWh.

The actual and normal energy sales for residential and commercial customers are shown in the Figure 4-2 and Figure 4-3 below.

Figure 4-2
NIPSCO Residential ("GWh")

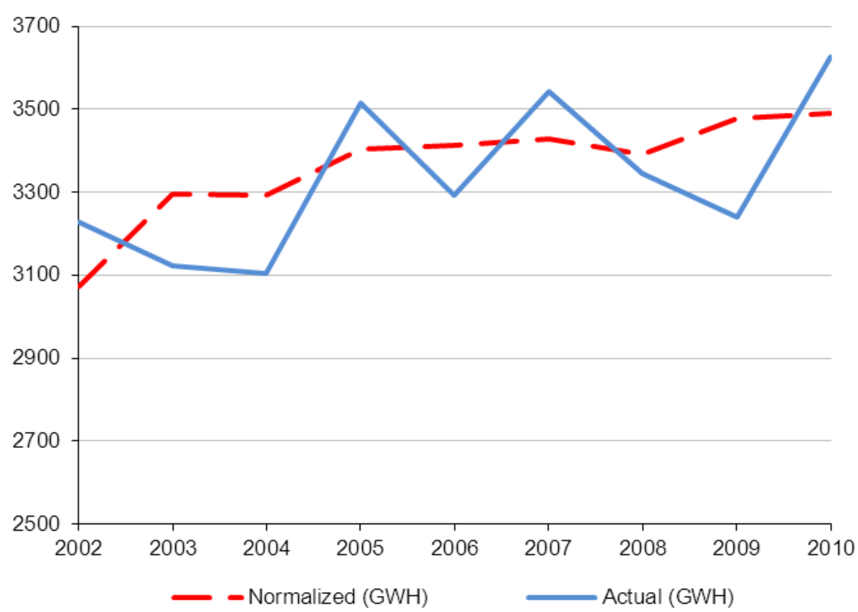
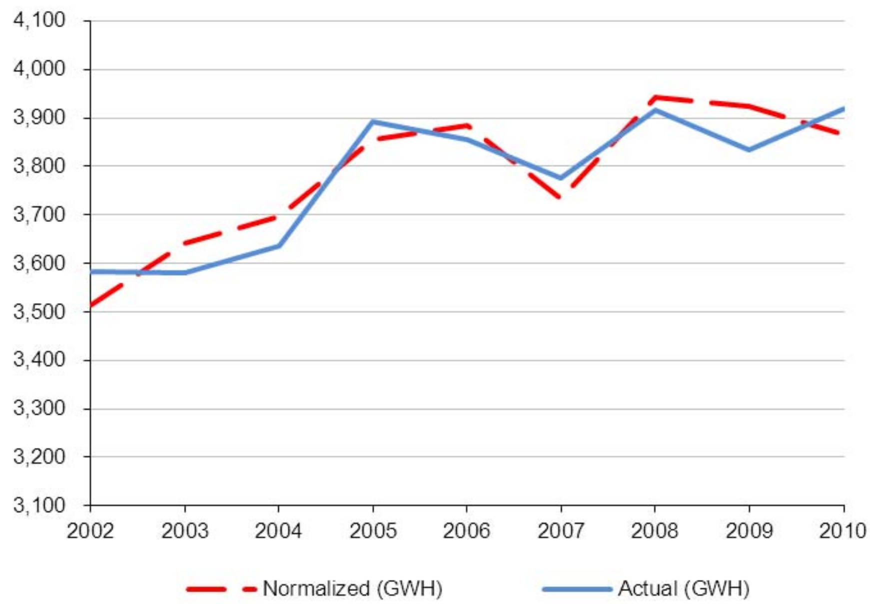


Figure 4-3
NIPSCO Commercial ("GWh")



Data Source – External:

Telvent - NIPSCO used two weather measures in the forecast, specifically CDD and HDD as defined by the National Oceanic and Atmospheric Administration ("NOAA"). The Company purchases weather data for three NOAA stations: Valparaiso, South Bend and Fort Wayne. For modeling purposes, the weather from these three stations is represented as a weighted average with the weights based on the geographical distribution of the weather-sensitive load. For the forecast period, the Company assumed weather data to be equal to normal, defined as the 1976-2005 average for both CDD and HDD. The weighted weather concepts for the peak hour model are cooling degree hours, heating degree hours and relative humidity.

IHS Global Insight - NIPSCO purchased the economic and demographic data from IHS Global Insight. Economic data used in the production of the forecast represents the most current information from IHS Global Insight as of December 2010.

Itron - Historical and forecasted saturation and efficiency data are obtained from Itron Inc., a national utility consulting firm. Itron produces an annual statistically adjusted end use model by census region reflecting historical and future saturation and efficiency trends. Itron works closely with the Energy Information Agency ("EIA") to embed the EIA's latest equipment saturation and efficiency trend forecasts into its annual models. NIPSCO used this information in the long-term residential forecast model.

Peak Hour Demand Forecast Model

The NIPSCO Peak Hour Demand Forecast Model is a function of composition and level of load – such as residential, commercial and industrial energy; cooling degree hours (summer) or heating degree hours (winter) at peak hour; and the level of relative humidity at peak hour.

Discussion of Forecast and Alternative Cases

Load Growth

The High and Low Load Growth cases were constructed from the Base Case. High and low case megawatt hours ("MWh") for the residential and commercial classes were calculated with the underlying model predicted values, along with the 80 percent confidence band around those values. That is, the range of predicted values was determined by adjusting the mean values of the forecast model predictions by the standard errors to reflect a 10 percent probability in each direction. This was done for both the customer and energy models. These resulting forecasted MWh, in addition to a 10 percent High and Low peak hour weather scenario, are used in the development of the High and Low peaks.

The High Case includes additional MWh sales reflecting industrial customer expansions currently being developed within NIPSCO's service territory. It also reflects additional industrial demand based on the load observed in 2007. Table 4-1 displays NIPSCO's Base, High and Low Load Forecast scenarios for selected years. A greater percent difference in the high and low peaks compared to the annual energies is due to greater swings in temperature and temperature-related consumption in the peak month than in other months.

Table 4-1
NIPSCO IRP Scenarios - Selected Year

	Energy Sales - GWh			Internal Demand - MW		
	Base	High	Low	Base	High	Low
Year	GWh	GWh	GWh	MW	MW	MW
2011	17,877	19,955	15,798	3,127	3,616	2,838
2016	19,116	21,323	16,909	3,455	3,875	3,036
2021	19,706	21,982	17,429	3,621	4,064	3,177
2026	20,248	22,590	17,907	3,785	4,254	3,317
2031	20,796	23,202	18,389	3,953	4,447	3,459
		v Base			v Base	
		High	Low		High	Low
		GWh	GWh		MW	MW
2011	-	0.1163	-0.1163	-	0.1564	-0.0924
2016	-	0.1155	-0.1155	-	0.1213	-0.1213
2019	-	0.1155	-0.1155	-	0.1226	-0.1226
2024	-	0.1156	-0.1156	-	0.1238	-0.1238
2031	-	0.1157	-0.1157	-	0.1250	-0.1250

Gigawatt hours ("GWh")

Forecast Results – Base Case

Over the forecast period, total energy and peak hour demand forecasts to grow at about 0.55 percent to 0.78 percent compounded annually. NIPSCO expects overall customer growth to increase about 0.5 percent annually. Table 4-2 summarizes NIPSCO's electric forecast.

Table 4-2
Electric Energy and Demand Forecast
FP0711a

	Energies (GWh)						Internal Peak Hour	
	Total			Total		Load		
Year	Retail *	% Change	Losses	Output	% Change	Factor	MW	% Change
2001	15,466		688	16,154		64.3%	3,003	
2002	15,792	2.11%	702	16,494	2.11%	62.8%	3,021	0.60%
2003	15,816	0.15%	703	16,519	0.15%	62.5%	3,065	1.46%
2004	16,191	2.37%	720	16,911	2.37%	63.1%	2,921	-4.70%
2005	16,656	2.87%	740	17,396	2.87%	68.1%	3,154	7.98%
2006	16,767	0.67%	733	17,500	0.60%	63.3%	3,238	2.66%
2007	16,904	0.82%	751	17,655	0.89%	62.7%	3,239	0.03%
2008	16,705	-1.18%	897	17,602	-0.30%	62.3%	3,076	-5.03%
2009	14,925	-10.66%	858	15,783	-10.33%	63.4%	2,696	-12.35%
2010	16,191	8.48%	915	17,106	8.38%	62.9%	3,103	15.09%
2011	16,929	4.56%	947	17,877	4.50%	63.2%	3,127	0.78%
2012	17,037	0.64%	953	17,990	0.64%	63.9%	3,214	2.78%
2013	17,502	2.73%	980	18,481	2.73%	64.0%	3,299	2.64%
2014	17,484	-0.10%	979	18,463	-0.10%	63.7%	3,307	0.26%
2015	17,501	0.10%	979	18,481	0.10%	63.5%	3,320	0.39%
2016	17,443	-0.33%	976	18,419	-0.33%	63.4%	3,314	-0.18%
2017	17,335	-0.62%	970	18,305	-0.62%	63.4%	3,293	-0.63%
2018	17,216	-0.68%	964	18,180	-0.68%	63.4%	3,272	-0.65%
2019	17,101	-0.67%	957	18,058	-0.67%	63.5%	3,247	-0.77%
2020	16,974	-0.74%	950	17,924	-0.74%	63.5%	3,222	-0.76%
2021	17,173	1.17%	961	18,135	1.17%	63.3%	3,269	1.44%
2022	17,313	0.81%	969	18,282	0.81%	63.1%	3,310	1.26%
2023	17,434	0.70%	976	18,409	0.70%	62.8%	3,344	1.04%
2024	17,565	0.75%	983	18,548	0.75%	62.6%	3,383	1.17%
2025	17,700	0.77%	991	18,690	0.77%	62.3%	3,423	1.19%
2026	17,839	0.79%	998	18,837	0.79%	62.1%	3,465	1.21%
2027	17,991	0.85%	1007	18,998	0.85%	61.8%	3,509	1.27%
2028	18,186	1.08%	1018	19,204	1.08%	61.5%	3,565	1.60%
2029	18,372	1.02%	1028	19,400	1.02%	61.2%	3,617	1.46%
2030	18,562	1.04%	1039	19,601	1.04%	61.0%	3,670	1.47%
2031	18,770	1.12%	1050	19,820	1.12%	60.6%	3,732	1.70%
2032	18,992	1.18%	1063	20,055	1.18%	60.3%	3,796	1.70%
	Compound Average Growth Rate 2011-2032							
	0.55%			**0.55%**			**0.78%**	

** Retail does not include bulk sales*

Table 4-3 displays the NIPSCO's forecast of Energies by Customer Class.

Table 4-3
Energies by Customer Class
FP0711a

Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Other (GWh)	Total (GWh)	Percent Change
2001	2,957	3,392	8,990	128	16,154	
2002	3,228	3,584	8,857	123	16,494	2.11%
2003	3,122	3,580	8,972	142	16,519	0.15%
2004	3,104	3,635	9,310	143	16,911	2.37%
2005	3,516	3,893	9,132	115	17,396	2.87%
2006	3,294	3,856	9,503	114	17,500	0.60%
2007	3,544	3,775	9,444	142	17,655	0.89%
2008	3,346	3,916	9,305	138	17,602	-0.30%
2009	3,241	3,834	7,691	159	15,783	-10.33%
2010	3,626	3,920	8,459	186	17,106	8.38%
2011	3,488	3,873	9,380	188	17,877	4.50%
2012	3,447	3,896	9,506	188	17,990	0.64%
2013	3,406	3,921	9,988	188	18,481	2.73%
2014	3,394	3,978	9,924	188	18,463	-0.10%
2015	3,424	4,034	9,855	188	18,481	0.10%
2016	3,435	4,066	9,753	189	18,419	-0.33%
2017	3,439	4,062	9,645	189	18,305	-0.62%
2018	3,441	4,059	9,526	189	18,180	-0.68%
2019	3,462	4,063	9,386	190	18,058	-0.67%
2020	3,465	4,074	9,246	190	17,924	-0.74%
2021	3,513	4,164	9,306	190	18,135	1.17%
2022	3,559	4,246	9,318	191	18,282	0.81%
2023	3,604	4,312	9,327	191	18,409	0.70%
2024	3,646	4,391	9,337	191	18,548	0.75%
2025	3,685	4,472	9,351	191	18,690	0.77%
2026	3,725	4,554	9,368	192	18,837	0.79%
2027	3,765	4,641	9,392	192	18,998	0.85%
2028	3,804	4,741	9,448	192	19,204	1.08%
2029	3,837	4,832	9,510	192	19,400	1.02%
2030	3,870	4,927	9,573	193	19,601	1.04%
2031	3,909	5,034	9,634	193	19,820	1.12%
2032	3,952	5,136	9,711	193	20,055	1.18%
Compound Average Growth Rate 2011-2032						
	0.60%	**1.35%**	**0.17%**	**0.14%**	**0.55%**	

Table 4-4 displays the forecast of customer counts by class. For documentation of the forecast, see Appendix A.

Table 4-4
Customer Counts by Class
FP0711a

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Total Customers
2001	381,440	47,286	2,643	801	432,170
2002	384,875	48,286	2,581	798	436,540
2003	387,922	49,249	2,543	793	440,507
2004	392,342	50,332	2,528	770	445,972
2005	395,849	51,261	2,515	765	450,390
2006	398,349	52,106	2,509	759	453,723
2007	400,991	52,815	2,509	755	457,070
2008	400,640	53,438	2,484	754	457,316
2009	400,016	53,617	2,441	746	456,820
2010	400,522	53,877	2,432	740	457,571
2011	401,097	54,143	2,454	742	458,436
2012	400,643	54,365	2,464	742	458,213
2013	400,530	54,732	2,469	742	458,472
2014	402,648	55,601	2,469	742	461,461
2015	404,755	56,366	2,469	742	464,333
2016	406,834	57,097	2,469	742	467,142
2017	408,933	57,631	2,469	742	469,775
2018	410,996	58,297	2,469	742	472,504
2019	413,021	58,968	2,469	742	475,200
2020	414,949	59,644	2,469	742	477,804
2021	416,755	60,448	2,469	742	480,414
2022	418,539	61,134	2,469	742	482,885
2023	420,269	61,676	2,469	742	485,155
2024	421,976	62,363	2,469	742	487,550
2025	423,748	63,046	2,469	742	490,005
2026	425,531	63,743	2,469	742	492,485
2027	427,225	64,444	2,469	742	494,880
2028	428,795	65,149	2,469	742	497,155
2029	430,307	65,721	2,469	742	499,239
2030	431,849	66,295	2,469	742	501,355
2031	433,386	67,021	2,469	742	503,619
2032	434,849	67,603	2,469	742	505,663
Compound Average Growth Rate 2011-2032					
	0.39%	**1.06%**	**0.03%**	**0.00%**	**0.47%**

Evaluation of Model Performance/Accuracy

NIPSCO tracks its forecast in terms of mean absolute error ("MAE"). Data for 1999-2010 show that the MAE of the one-year-ahead peak hour demand forecast is 4.1percent; the two-year-ahead forecast has a 5.1 percent MAE; and the MAE for the five-year-ahead forecast is 4.5 percent. These represent total forecast error including the effect of abnormal weather at peak. The comparable MAE for GWh sales is 3.0 percent for the one-year-ahead forecast; 4.7 percent for the two-year-ahead forecast; and 4.0 percent for the five-year-ahead forecast. Class comparisons to weather-normalized actual data show variances with residential and commercial of 2.8 percent-4.0 percent MAE for the one-year-ahead and two-year-ahead forecasts. Industrial GWh are not weather normalized and show 6.7 percent and 10.6 percent MAE for the one-year-ahead and the two-year-ahead forecast.

Tables 4-5 thru 4-8 show data for 1999-2010 for total GWh sales and peak hour MW and compare forecasts to actual data not normalized for weather. GWh sales by class are available beginning in 2007 and compared to actual data normalized for weather.

Table 4-5
Internal Peak Hour Demand - MW
Absolute % Variance of Forecast v Actual

Year	Actual *	1-Year Ahead Forecast	1-Year Ahead % Var.	2-Year Ahead Forecast	2-Year Ahead % Var.	5-Year Ahead Forecast	5-Year Ahead % Var.
1999	2,972	3,045	2.4%	2,747	8.2%	2,915	2.0%
2000	2,873	2,830	1.5%	3,080	6.7%	2,917	1.5%
2001	3,003	2,911	3.2%	2,868	4.7%	2,847	5.5%
2002	3,021	2,876	5.0%	2,953	2.3%	2,844	6.2%
2003	3,065	2,989	2.5%	2,931	4.6%	3,221	4.8%
2004	2,921	3,052	4.3%	3,030	3.6%	2,951	1.0%
2005	3,154	3,046	3.5%	3,091	2.0%	3,104	1.6%
2006	3,238	3,099	4.5%	3,077	5.2%	3,064	5.7%
2007	3,239	3,154	2.7%	3,134	3.4%	3,146	3.0%
2008	3,076	3,224	4.6%	3,188	3.5%	3,201	3.9%
2009	3,239	3,024	7.1%	3,248	0.3%	3,170	2.2%
2010	3,239	2,965	9.3%	3,088	4.9%	3,232	0.2%
Average			**4.2%**		**4.1%**		**3.1%**

** Actual peak not adjusted for weather. Forecasted peaks assume normal weather; therefore, variance includes weather effect.*

Table 4-6
Total GWh including Losses
Absolute % Variance of Forecast v Actual

Year	Actual *	1-Year Ahead Forecast	% Var.	2-Year Ahead Forecast	% Var.	5-Year Ahead Forecast	% Var.
1999	16,313	15,853	2.9%	13,914	17.2%	15,275	6.8%
2000	16,655	16,430	1.4%	16,989	2.0%	17,162	3.0%
2001	16,154	16,694	3.2%	17,501	7.7%	16,252	0.6%
2002	16,494	16,538	0.3%	16,733	1.4%	16,199	1.8%
2003	16,519	16,761	1.4%	16,907	2.3%	18,493	10.7%
2004	16,911	17,224	1.8%	17,078	1.0%	18,018	6.1%
2005	17,396	17,031	2.1%	17,531	0.8%	17,544	0.8%
2006	17,500	16,750	4.5%	17,235	1.5%	17,544	0.3%
2007	17,655	17,725	0.4%	16,916	4.4%	17,928	1.5%
2008	17,602	18,355	4.1%	17,938	1.9%	18,374	4.2%
2009	15,783	16,898	6.6%	18,446	14.4%	17,716	10.9%
2010	17,106	15,910	7.5%	17,340	1.3%	17,373	1.5%
Average			**3.0%**		**4.7%**		**4.0%**

** Actual GWh not adjusted for weather. Forecasted GWh assumes normal weather; therefore, variance includes weather effect.*

Table 4-7
Residential and Commercial GWh
Absolute % Variance of Forecast v Actual

	Normal *	1-Year Ahead Forecast	% Var.	2-Year Ahead Forecast	% Var.
2007	7,162	7,477	4.39%	7,422	3.62%
2008	7,334	7,641	4.19%	7,600	3.63%
2009	7,403	7,534	1.77%	7,757	4.78%
2010	7,356	7,431	1.02%	7,659	4.12%
Average			**2.84%**		**4.04%**

** Adjusted for weather*

Table 4-8
Industrial GWh
Absolute % Variance of Forecast v Actual

		1-Year Ahead		2-Year Ahead	
	Actual *	Forecast	% Var.	Forecast	% Var.
2007	9,444	9,441	0.03%	8,749	7.36%
2008	9,305	9,861	5.97%	9,523	2.34%
2009	7,691	8,579	11.55%	9,833	27.85%
2010	8,459	7,692	9.07%	8,879	4.96%
Average			**6.65%**		**10.63%**

** No weather effect measured for industrial load*

2011

SECTION 5: EXISTING RESOURCES

NIPSCO

INTEGRATED RESOURCE PLAN

Highlights – Existing Resources

- ***Supply-Side Resources used to serve customers include 3,322 MW of coal, natural gas and hydroelectric generation, as well as 100 MW of wind generation purchases.***
- ***Demand-Side Resources include energy efficiency, energy conservation and demand response programs which help to reduce customers' electricity consumption, or shift energy consumption from peak consumption hours to off-peak hours.***
- ***As a member of MISO, NIPSCO has access to an efficient liquid market.***
- ***NIPSCO actively manages fuel supplies to its coal and gas generators.***
- ***NIPSCO supplements its generation resources using its interruptible tariff services, and when interruptible services are not available, NIPSCO will use the proposed MISO capacity auction on bi-lateral contracts.***

NIPSCO serves customers with a portfolio of supply-side and demand-side resources. The resources are designed to match the characteristics of NIPSCO's load.

Meeting Customers' Future Energy Needs

As part of the planning process, NIPSCO identifies existing resources. These resources must be capable of meeting customers' forecast capacity and energy needs. To be considered, the resources must be safe, reliable and cost effective. NIPSCO must also take into account the business climate in which we anticipate operating within.

NIPSCO operates within MISO, the Regional Transmission Organization ("RTO"), and is subject to North American Electric Reliability Corporation ("NERC") standards. NIPSCO has registered with NERC as a Distribution Provider, Generator Owner, Generator Operator, Load Serving Entity, Purchasing-Selling Entity, Resource Planner and Transmission Planner. NIPSCO is registered as a Balancing Authority, Transmission Operator and Transmission Owner in MISO. Each Registered Entity is subject to compliance with applicable NERC and Regional Reliability Organization ("RRO") standards approved by Federal Energy Regulatory Commission ("FERC"). Reliability*First* Corporation is the RRO.

Supply-Side Resources – A Description of NIPSCO Generation

NIPSCO's generation portfolio consists of the following coal and gas-fired generation sites:

- Bailly Generating Station ("Bailly"),
- Michigan City Generating Station ("Michigan City"),
- D.H. Mitchell Generating Station ("Mitchell"),
- R.M. Schahfer Generating Station ("Schahfer") and
- Sugar Creek Generating Station ("Sugar Creek").

The portfolio also includes two hydroelectric generating sites ("Norway Hydro" and "Oakdale Hydro") and two long-term PPAs for wind generation ("Buffalo Ridge" and "Barton").

NIPSCO-Owned Supply Resource – Bailly

Bailly is located on a 100-acre site on the shore of Lake Michigan in Porter County, Indiana. Bailly's two base-load units and one peaking unit came on-line over a six-year period ending in 1968. The units are equipped with various environmental control technologies, including FGD to reduce SO_2, Selective Catalytic Reduction ("SCR") and Over-Fire Air ("OFA") systems to reduce nitrogen oxide ("NO_x") emissions as required by law. Environmental Protection Agency ("EPA") regulations for coal ash and cooling water may also impact Bailly Units 7 and 8. The individual characteristics of the Bailly units are provided on Table 5-1. The FGD at Bailly operates under a service agreement. That agreement is near the end of its primary term. NIPSCO and the FGD's owner (Pure Air) are presently negotiating a contract extension. NIPSCO may file an addendum to its IRP if this negotiation results in an agreement that deviates materially from the present agreement.

Table 5-1
Bailly Unit Information

	Unit 7	Unit 8	Unit 10
NET Output			
Min (MW)	100	200	----
Max (MW)	160	320	31
Boiler	Babcock & Wilcox	Babcock & Wilcox	----
Burners	4 Cyclone	8 Cyclone	----
Main Fuel	Coal	Coal	Gas
Turbine	General Electric	General Electric	Westinghouse
Frame	D6	G2	W301G
In-Service	11/30/62	7/31/68	11/30/68
Environmental Controls	FGD, SCR, OFA	FGD, SCR, OFA	----

NIPSCO-Owned Supply Resource - Michigan City

Michigan City is located on a 134-acre site on the shore of Lake Michigan in Michigan City, Indiana. Michigan City has one base-load units, Unit 12. Unit 12 is equipped with SCR and OFA systems to reduce NO_x emissions as required by law. Unit 12 burns low and medium sulfur coal blends to minimize SO_2 emissions. Major upgrades for emissions controls are being evaluated for installation on Unit 12 in order to comply with the Consent Decree,[1] the Maximum Achievable Control Technology ("MACT") and Cross-State Air Pollution Rule ("CSAPR"). The 2011 IRP presumes an FGD is constructed for Unit 12. Based on recent feedback from stakeholders, NIPSCO plans to provide additional analysis to the

[1] January 13, 2011 agreement among the EPA, Department of Justice, Indiana Department of Environmental Management and NIPSCO to settle the NIPSCO EPA New Source Review Notice of Violation lodged with the United States District Court for the Northern District of Indiana Hammond Division ("Northern District") (the "Consent Decree"). The Consent Decree was placed on public notice in the Federal Register on January 20, 2011. On July 22, 2011, the Northern District issued an Order in Case No. 2:11-CV-16 JVB approving the Consent Decree. The Consent Decree requires that NIPSCO operate all existing pollution control equipment and install additional pollution control equipment.

stakeholders, and may file an addendum to this IRP. EPA regulations for coal ash and cooling water may also impact Michigan City Unit 12. The individual unit characteristics of Michigan City are provided on Table 5-2.

Table 5-2
Michigan City Unit Information

	Unit 12
NET Output	
Min (MW)	250
Max (MW)	469
Boiler	Babcock & Wilcox
Burners	10 Cyclone
Main Fuel	COAL
Turbine	General Electric
Frame	G2
In-Service	5/31/74
Environmental Controls	SCR, OFA

NIPSCO-Owned Supply Resource - Mitchell

Mitchell is located on a 100-acre site in the northwest corner of Gary, Indiana, directly north of the Gary Airport on the shore of Lake Michigan. NIPSCO operates Mitchell's gas-fired simple cycle turbine Unit 9A as dispatched, and has included Unit 9A as an available supply resource through 2013. Unit 9A has been identified for retirement in 2013. The individual unit characteristics of Mitchell are provided in Table 5-3.

Table 5-3
Mitchell Unit Information

	Unit 9A
NET Output	
Min (MW)	----
Max (MW)	17
Boiler	----
Burners	----
Main Fuel	Gas
Turbine	General Electric
In-Service	12/1/66

NIPSCO-Owned Supply Resource – Schahfer

Schahfer is located on approximately a 3,150-acre site two miles south of the Kankakee River in Jasper County, near Wheatfield, Indiana. Schahfer is the largest of NIPSCO's generating stations. Schahfer's four coal-fired base-load units and two gas-fired simple cycle peaking units came on-line over an 11-year period ending in 1986. The Schahfer units are equipped with significant environmental control technologies, including FGD to reduce SO_2 emissions and SCR, Low NO_x Burners ("LNB") and OFA systems to reduce NO_x emissions as required by law. Unit 14 burns low and medium sulfur coal blends and Unit 15 burns low-sulfur coals to minimize SO_2 emissions. As part of the Company's Clean Air Interstate Rule ("CAIR") Compliance Phase I Strategy, FGD system upgrades to improve SO_2 removal efficiency were completed for Units 17 and 18 in 2010 and 2009, respectively. Installation of a new LNB with OFA system was completed on Unit 15 in 2009. Installations of new FGD plants on Units 14 and 15 are in progress and expected to be completed in 2013 and 2015, respectively. EPA regulations for coal ash and cooling water may also impact Schahfer. The individual unit characteristics of Schahfer are provided in Table 5-4.

Table 5-4
Schahfer Unit Information

	Unit 14	Unit 15	Unit 17	Unit 18	Unit 16A	Unit 16B
NET Output						
Min (MW)	250	200	125	125	----	----
Max (MW)	431	472	361	361	78	77
Boiler	Babcock & Wilcox	Foster Wheeler	Combustion Engineering	Combustion Engineering	----	----
Burners	10 Cyclone	6 Pulverizers	6 Pulverizers	6 Pulverizers	----	----
Main Fuel	Coal	Coal	Coal	Coal	Gas	Gas
Turbine	Westinghouse	General Electric	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Frame	BB44R	G2	BB243	BB243	D501	D501
In-Service	12/31/76	10/31/79	4/28/83	2/14/86	12/31/79	12/31/79
Environmental Controls	SCR, OFA	LNB, OFA	FGD, LNB, OFA	FGD, LNB, OFA	----	----

NIPSCO-Owned Supply Resource - Sugar Creek

Sugar Creek is located on a 281-acre rural site near the west bank of the Wabash River in Vigo County, Indiana. The gas-fired CTs and CCGT were available for commercial operation in 2002 and 2003, respectively. Sugar Creek was purchased by NIPSCO in July 2008, and is NIPSCO's newest electric generating facility. Sugar Creek has been registered as a MISO resource since December 1, 2008. Two Combustion Turbines ("CT") generators and one steam turbine generator are operated in the CCGT mode. Environmental control technologies at Sugar Creek include SCR to reduce NO_x, and dry low NO_x ("DLN") combustion systems. The individual unit characteristics of Sugar Creek are provided in Table 5-5.

Table 5-5
Sugar Creek Unit Information

	CT 1A	CT 1B	SCST
NET Output			
Min (MW)	110	110	110
Max (MW)	152	154	229
Heat Recovery Steam Generator	Vogt Power	Vogt Power	---
Main Fuel	Gas	Gas	Steam
Turbine	GE	GE	GE
Frame	7FA	7FA	D11
In-Service	6/15/2002	6/15/2002	6/15/2003
Environmental Controls	SCR, DLN	SCR, DLN	---

NIPSCO-Owned Supply Resource - Norway Hydro and Oakdale Hydro

Norway Hydro is located near Monticello, Indiana on the Tippecanoe River. The dam creates Lake Shafer, a body of water approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydro has 4 generating units capable of producing up to 7,200 kilowatts (“kW”). However, Norway Hydro output is dependent on river flow and the typical maximum plant output is 4 MW. The individual unit characteristics of the Norway Hydro are provided in Table 5-6.

Table 5-6
Norway Hydro Unit Information

	Unit 1	Unit 2	Unit 3	Unit 4
NET Output				
Min (MW)	---	---	---	---
Max (MW)	2	2	2	1.2
In-Service	1923	1923	1923	1923
Main Fuel	Water	Water	Water	Water

Oakdale Hydro is located near Monticello, Indiana along the Tippecanoe River. The dam creates Lake Freeman, a body of water approximately 12 miles long with a maximum depth of 45 feet, which functions as its reservoir. Oakdale Hydro has 3 generating units capable of producing up to 9,200 kW. However, the Oakdale Hydro output is dependent on river flow and the typical maximum plant output is 6 MW. The individual unit characteristics of the Oakdale Hydro are provided in Table 5-7.

Table 5-7
Oakdale Hydro Unit Information

	Unit 1	Unit 2	Unit 3
NET Output			
Min (MW)	---	---	---
Max (MW)	4.4	3.4	1.4
In-Service	1925	1925	1925
Main Fuel	Water	Water	Water

NIPSCO PPAs - Barton and Buffalo Ridge Wind

NIPSCO is currently engaged in a 20-year PPA with Iberdrola, in which NIPSCO will purchase generation from Barton. Barton, located in Worth County, Iowa, went into commercial operation on April 10, 2009. The individual unit characteristics of Barton are provided in Table 5-8.

Table 5-8
Barton Wind Information

NET Output	
Per Unit (MW)	2.0
Number of Units	25
Total Output (MW)	50.0
In-Service	04/10/2009
Main Fuel	Wind

NIPSCO is also engaged in a 15-year PPA with Iberdrola, in which NIPSCO will purchase generation from Buffalo Ridge. Buffalo Ridge, located in Brookings County South Dakota, went into commercial operation on April 15, 2009. The individual unit characteristics of Buffalo Ridge are provided in Table 5-9.

Table 5-9
Buffalo Ridge Wind Information

NET Output	
Per Unit (MW)	2.1
Number of Units	24
Total Output (MW)	50.4
In-Service	04/15/2009
Main Fuel	Wind

Total Resource Summary/Portfolio Composition

Table 5-10 provides the net capacity, type of fuel burned and in-service dates for each of NIPSCO's existing generating units.

Table 5-10
Existing Generating Units

Unit	NDC (MW)	Type	Typical Fuel	In-Service Date
Michigan City 12	469	Steam	Coal	May 31, 1974
Mitchell 9A	17	Combustion Turbine	Natural Gas	December 1, 1966
Bailly 7	160	Steam	Coal	November 30, 1962
Bailly 8	320	Steam	Coal	July 31, 1968
Bailly 10	31	Combustion Turbine	Natural Gas	November 30, 1968
Schahfer 14	431	Steam	Coal	December 31, 1976
Schahfer 15	472	Steam	Coal	October 31, 1979
Schahfer 16A	78	Combustion Turbine	Natural Gas	December 31, 1979
Schahfer 16B	77	Combustion Turbine	Natural Gas	December 31, 1979
Schahfer 17	361	Steam	Coal	April 28, 1983
Schahfer 18	361	Steam	Coal	February 14, 1986
Norway	4	Hydro	Hydro	June 8, 1923
Oakdale	6	Hydro	Hydro	November 11, 1925
Sugar Creek CT 1A	152	Combustion Turbine	Natural Gas	June 15, 2002
Sugar Creek CT 1B	154	Combustion Turbine	Natural Gas	June 15, 2002
Sugar Creek SCST	229	Steam	Natural Gas	June 15, 2003
Barton(PPA)	50	Wind	Wind	April 10, 2009
Buffalo Ridge(PPA)	50	Wind	Wind	April 15, 2009
Subtotal	2,574		Coal	
Subtotal	738		Natural Gas	
Subtotal	10		Hydro	
Subtotal	100		Wind	
Total System	**3,422**			

NIPSCO and the MISO Wholesale Electricity Market

NIPSCO's View of MISO's Generation Resource Pool

MISO demonstrates an important trait key to NIPSCO's long term plans – ongoing liquidity. MISO provides an enduring, relatively efficient market for marginal purchases and sales of electricity. There are many changes that affect MISO's generation resource pool. In addition to changes in MISO membership, there are many regulatory concerns that are being monitored.

MISO Membership - MISO membership has been in flux for several years:

Entrants - Since 2009, MISO has seen the integration of MidAmerican Energy (5,216 MW Peak, 6,845 MW Generation), Dairyland Power Cooperative (1,030 MW Peak, 1,013 MW Generation), and Big Rivers Electric Corporation (1,621 MW Peak, 1,759 MW Generation). Entergy has recently announced its intent to join the MISO. If all five Entergy Operating Companies join the MISO, they will bring an additional 22,000 MW of load and 30,000 MW of generation. There are still many regulatory and operational issues to address. Entergy is projected to be integrated into the MISO footprint by the end of 2013.

Exits - First Energy withdrew from MISO and joined PJM Interconnection LLC ("PJM") effective June 1, 2011, taking with it 13,600 MW of generation and a peak load over 13,000 MW. Duke Ohio and Duke Kentucky are also planning on leaving the MISO footprint by the end of 2011. They would be leaving the MISO footprint with approximately 5,300 MW of load and 5,700 MW of generation and joining PJM on January 1, 2012.

Potential Regulatory Impacts - MISO has completed an initial study on the impact of proposed EPA rules on its resource pool. About half of MISO's generation is sourced from coal units; about half of MISO's coal generation pool would require additional controls to comply with EPA rules. Due to the high cost of retrofits, some coal units will be retired. NIPSCO is participating in MISO's continued efforts to conduct impact studies.

There has been talk for some time of a national and/or State renewable requirement. While NIPSCO has been proactive in securing renewable (wind) resources, any additional or new renewable ruling would have an impact on future resource considerations. The MISO currently has approximately 10,000 MW of wind generation within its footprint. There is approximately another 48,000 MW of wind generation in the study queue. Operational issues concerning the amount of wind generation in the MISO queue and wind generation saturation are being addressed in various MISO Stakeholder committees.

The MISO is also working very hard on accommodating Demand Resources into its markets. Demand resources come in many different classes including load modifying resources, emergency demand response ("EDR"), and behind the meter generation. Rules are being worked on to afford these resources the same opportunity as traditional generation to the extent possible. NIPSCO is an active participant in the Stakeholder processes addressing demand response, and supports its development.

Fuel Management for Supply-Side Resources

Coal Procurement and Inventory Practices

Coal Acquisition Strategy - NIPSCO employs a multifaceted strategy to guide coal supply and acquisition activities associated with the fueling of its coal-fired units. Those strategies include: (1) procuring the best coal for efficient unit operations; (2) providing for environmental compliance; (3) maintaining targeted inventory levels; (4) ensuring delivery of coal in a timely and cost-effective manner; and (5) maximizing contractual flexibility by procuring coal types that can be used in more than one unit.

Coal Procurement - NIPSCO develops a five-year baseline coal strategy. This strategy is used as a tool to determine appropriate coal purchases and inventory requirements. The fuel budget is dynamic and is updated on a periodic basis in response to system needs and market conditions.

Coal Pricing Outlook – Coal is generally sold in a bilateral market on a contract basis. Coal competes for market share against other fuels on a "value in use" basis, i.e., environmental externalities price in to the value of the commodity. Also, coal prices are linked with the supply and demand for coal, coal extraction costs, transport costs, and more generally with the overall supply and demand balance for energy. The discovery and exploitation of North American shale gas resources appears to have fundamentally altered the price relationship between coal and natural gas. Coal prices have continued to rise with extraction costs and rail transport costs, while natural gas prices remain relatively flat and economical. With the economy continuing to lag, coal producers are looking overseas to export coal, especially coals that can be sold as metallurgical coal. Illinois Basin producers are exporting coal to the United Kingdom, Portugal, Germany and North Africa. Powder River Basin ("PRB") coal producers are attempting to boost West Coast export of PRB coal. Targeted countries for this coal are China, South Korea, Japan, India and other Pacific Rim countries. Central Appalachia and Northern Appalachia coal continues to be exported due to an increasing demand for metallurgical coal.

Generally rising coal prices and declining Appalachia coal production have brought market share to the Illinois Basin. Several new mines are opening up in the Illinois Basin, particularly in the State of Illinois. Illinois Basin coal producers are banking on its high sulfur coal as not only being a potential export resource, with additional scrubbers continuing to be installed, the appetite for domestic high sulfur coal will escalate. Also, Southeast utilities are targeting Illinois Basin coal on a long term basis as a replacement for Columbian and Central Appalachia coal.

Another factor impacting the price of coal, particularly underground mined coal, is the Mine Safety and Health Administration, which is pushing to enact more stringent regulations to protect miners. Enhanced regulation has adversely impacted mine productivity. We expect that increased compliance costs may eventually be passed on to utilities and other coal customers.

Lastly, although coal still enjoys an economic advantage over natural gas, current and future environmental regulations will jeopardize that advantage on a marginal basis. With heavier government regulation in the mining industry, environmental regulations impacting air and water, and the potential of the government declaring fly ash a hazardous waste, this economic advantage continues to erode.

NIPSCO Coal Pricing Outlook - NIPSCO procures coal from three geographic regions in the United States, the PRB, Indiana's Illinois Basin, and Northern Appalachia. Market demand for Illinois Basin coal has increased for reasons stated above, and therefore, pricing has steadily risen. Northern Appalachia coal used by NIPSCO as a blend fuel in two of its cyclone units is being exported as a near metallurgical coal. This coal has a robust market overseas and is consequently priced accordingly. Also, the price of Northern Appalachia coal is expected to remain volatile due to its higher heat content and its international appeal compared to Illinois Basin and PRB coal. PRB coal producers appear to be currently exhibiting market discipline in an effort to bolster the price of PRB coal above the current market price. PRB coal pricing is expected to escalate in 2012 and 2013 due to strong demand for low sulfur coal caused by the EPA's CSAPR.

Coal and Issues of Environmental Compliance - Depending on the manner and extent of current and future environmental regulations, NIPSCO's coal purchasing strategy will always be to meet or exceed these environmental requirements.

Maintenance of Coal Inventory Levels - NIPSCO has an ongoing strategy to maintain a stable, controllable coal inventory (solid fuel inventory). NIPSCO reviews solid fuel inventory target levels annually and makes adjustments. These adjustments are in anticipation of changes in supply availability relative to demand, transportation constraints and unit consumption. The Company modifies target inventory levels on a unit-by-unit basis depending on the unit consumption, transportation cycle times, reliability of coal supply and station coal handling operations.

Forecast of Coal Delivery and Transportation Pricing - To ensure the delivery of fuel in a timely and cost-effective manner, NIPSCO negotiates and executes transportation contracts contemporaneously with coal supply contracts, evaluates all fuel procurement options on a delivered basis, and this includes a complete evaluation of all potential logistical issues.

Coal deliveries, excluding exceptional weather conditions, have become more fluid in all geographic regions, particularly shipments originating in the PRB region due to infrastructure improvements. Additionally, because of the current economic conditions, there continues to be less rail traffic, and consequently, less congestion. However, when the economy does improve, railroads will need to continue making major investments in infrastructure and capital equipment to ensure timely deliveries.

Transportation rates are trending upward and one of the driving factors is the volatility of diesel fuel. Railroads incorporate fuel surcharge mechanisms in transportation agreements to allow for recovery of the cost of the diesel fuel. Mileage-based fuel surcharges are more equitable for the shipper but rate fuel adjusters based on a price index continue to be utilized by some railroads to adjust for oil market volatility. This volatility in cost is then passed on to shippers such as NIPSCO. NIPSCO is currently investigating ways to mitigate this diesel fuel cost volatility through hedging alternatives. In the meantime, NIPSCO will continue to verify that all fuel surcharges imposed by the railroads meet the contractual terms of the transportation agreement negotiated by the parties.

Also, the federal government has ordered the railroad industry to install what is called Positive Train Control. This system attempts to create a fail-safe operating environment to prevent train-to-train collisions, along with other safety improvements. The project will cost approximately $8 billion for the freight industry and $2 billion for the commuter industry. The Federal Railroad Administration deadline for implementation is tentatively scheduled for December 31, 2015.

NIPSCO Transportation Pricing Outlook - The Surface Transportation Board recently initiated an exploration of the state of competition in the railroad industry. NIPSCO has limited rail options at the origin and destination for most of its transportation moves, and is further disadvantaged due to its geographical location. Not only is rail transportation limited, other transport modes (trucking and barging) are infeasible. Further, NIPSCO's largest generating station, Schahfer, is captive to one railroad. All coal delivered by this railroad to Schahfer is transported under escalated transportation rates and onerous fuel surcharges. Increased rail competition, particularly at Schahfer, would mitigate these costs. A north/south Indiana railroad providing direct access to Schahfer, and potential access to other industry in Northern Indiana, and the Port of Indiana, would allow Schahfer direct access to burn Indiana coal, and also be a possible economic stimulus for the northern region. Currently, the interchange for Indiana coal transported to Schahfer is near Chicago, adding miles to the transport route, increasing the delivered cost of Indiana coal to the station.

PRB and Illinois Basin transportation rates currently, and in the near term, are expected to continue to increase at some factor above the Consumer Price Index ("CPI"). However, fuel surcharges have escalated with the corresponding increase in diesel fuel prices. Currently, crude oil is averaging in the mid-$80s per barrel but spiked up over $110 per barrel during summer 2011.

Coal Contractual Flexibility, Deliverability and Procurement - Coal purchasing contracts are typically three to five years in term. Spot purchases are made on an as-needed basis in response to inventory fluctuations. In an effort to avoid inventory fluctuations and accommodate unit maintenance outages, most coal types under contract can be used in more than one unit. The fuel blending strategy can also be adjusted to conserve a particular type of coal if supply problems are being experienced. Both coal and rail transportation contracts have force majeure clauses, which cover events beyond the reasonable control of the party affected that prevent the mining, processing, or loading of coal at the mines, receiving, transporting, or delivering of coal by the rail carriers, or accepting, unloading, or burning of coal at the generating stations.

Natural Gas Procurement

NIPSCO purchases the gas for Sugar Creek through a gas supply contract with an energy manager who delivers the gas at the Tennessee/Midwestern interconnect; at the plant interconnect with the pipeline, or other locations along the Midwestern pipeline upon request of NIPSCO. Since June 1, 2010, NIPSCO has nominated and balanced the gas supply needs of Sugar Creek reducing fees paid to an energy manager. These spot purchases are made at Day-Ahead or Intra-day pricing depending on market and operational conditions.

For its other CTs, NIPSCO currently has a separate gas supply contract with a different energy manager. NIPSCO does not anticipate any long-term difficulties in securing gas and acquiring balancing services to serve Sugar Creek or the CTs at its other facilities.

Hedging Strategies for Electric Generation

NIPSCO's Commission-approved fuel hedging plan makes the following presumptions:

- All NIPSCO coal costs are fixed, given the longer term coal supply contracts.
- Remaining on-peak energy needs are split between CCGT gas fired generation (Sugar Creek) and open market purchases from the MISO.
- Gas used to generate power is hedged to 50 percent of the exposure, leaving half at market sensitive pricing.
- Similarly, 50 percent of the MISO electric energy purchases are hedged.

Appropriate hedging instruments, including NYMEX Natural Gas and Electricity Futures, are used to hedge out exposure and remove basis risk.

Short-Term Capacity and Energy Procurement

Generation capacity additions are added in blocks. NIPSCO utilizes the IRP process to facilitate its long term resource decisions. For example, the acquisition of Sugar Creek was secured via an Request for Proposals ("RFP") process and was consistent with NIPSCO's IRP. However, during the process, due to changes in the economy, the magnitude of capacity needed decreased significantly, and the plan was not fully executed. Short- term capacity additions, defined as for duration of one planning year or less, have been secured via bilateral transactions directly between the counterparties. NIPSCO may be able to meet supplement its projected capacity needs with additional interruptible service. If such resources are not available, NIPSCO will supplement its capacity needs with either through the proposed MISO Capacity Auction or bi-lateral contracts.

NIPSCO supplements its generation resources with energy secured through the MISO Day Ahead and/or Real Time markets. This can occur during times when demand exceeds resource capabilities as well as when NIPSCO is able to secure energy at prices below the incremental cost of operating its own generating resources.

Operations Management and Dispatch Implications for Supply-Side Resources

Considerations for Environmental Compliance – Consent Decree, CSAPR and Utility MACT

As previously noted, NIPSCO recently entered into a Consent Decree with the EPA requiring NIPSCO to reduce emissions over a period of years through unit operations, fuel choices, and capital improvements. In order to meet the terms of the Consent Decree, NIPSCO has developed predictive tools to predict effluent emission levels based on unit operations, as well as determine levels of output for the individual generators that can help reduce the overall emissions. Based on output from the predictive tools and current operations statistics, NIPSCO modifies unit operations and unit offers for dispatch into MISO as needed in order to remain environmentally compliant.

Considerations for new NIPSCO Tariff Services

NIPSCO has a number of recently-approved and proposed tariff offerings. The recently-approved feed-in tariff in IURC Cause No. 43922, offers the additional ability for small independent power producers of renewable energy, and residential customers with renewable energy resources, to offset their electric consumption costs by selling to NIPSCO power generated via these renewable resources. The feed-in tariff is an experimental rate. It allows NIPSCO access to a diverse mix of small capacity renewable resources to include new wind, solar, biomass, and hydroelectric technologies. The initial offering under this tariff is limited to 30 MW, and (i) no one technology may exceed 50 percent of the available 30 MW, (ii) 500 kW is reserved for solar projects of less than 10 kW capacity and (iii) 500 kW is reserved for wind projects of less than 10 kW capacity. The Commission has also recently adopted new net metering regulations that allow for customers with eligible facilities up to 1 MW to participate under NIPSCO’s net metering tariff.

Recently, NIPSCO collaborated with industrial customers, aggregators, and the other utilities within Indiana to develop energy-only Demand Response and EDR tariffs in IURC Cause No. 43566. The tariffs proposed by NIPSCO were approved by the Commission and are constructed in a way that allows customers and aggregators to price and offer demand reduction for behind the meter generation into the MISO Day-Ahead Market facilitated via NIPSCO. When the Demand Response load reductions that are offered into the market clear economically, the customer is expected to reduce load accordingly. The EDR clears the market only during emergency situations, as declared by MISO. Currently, MISO is awaiting an order from FERC on its Demand Response filing.

NIPSCO has offerings for Interruptible Service under current rates and proposed rates filed within IURC Cause No. 43969. The Interruptible Service available to customers under current rates has been in place and operated for some time. A few of NIPSCO’s largest industrial customers are willing and able to interrupt service to benefit all customers. The interruptible credits are provided for two reasons, reliability and economic, each of which provides value to all customers. Within Cause No. 43969, NIPSCO, along with other settling parties, are seeking approval of a settlement agreement that includes a new Interruptible Service Rider that would provide multiple options to customers and would allow NIPSCO flexibility in dispatching customers when market prices are expected to be high. The various Interruptible Service Rider options reflect the ability of certain customers to curtail load (duration, frequency, notice) and price the more restrictive curtailment rights lower relative to liberal curtailment rights granted by the rider. NIPSCO's other customers "pay" for the demand-side resource commensurate with the quality of resource received. All customers benefit through the deferred investment in more generation resources.

Demand-Side Resources – A Description of NIPSCO Program Offerings

Programs Offered

The following DSM programs have been approved by the Commission in Cause No. 43912. They include both conservation and demand response programs. The initial semi-annual request for Commission approval of DSM Adjustment Factors was approved in Cause No. 43618 DSM1.

Core Programs

- Residential Lighting
- Residential Low Income Weatherization
- Residential Home Energy Efficiency Audit
- Energy Efficient Schools
- Commercial and Industrial Prescriptive

Core Plus Programs

- Residential New Construction
- Residential Weatherization
- Residential Appliance Recycling
- Residential and Non-Residential A/C Cycling
- Residential Direct Install
- Residential Conservation
- Non-Residential New Construction
- Non-Residential Custom Incentive

Energy Savings Goal

These programs contribute towards the energy savings goals set forth in the order in Cause No. 42693, Phase II ("Generic DSM Order"). The Generic DSM Order established an overall annual energy savings goal of 2 percent to be achieved by jurisdictional electric utilities in the State of Indiana within 10 years, with interim savings to be achieved in years one through nine. The annual incremental gross savings targets are not net of any free-riders and are based on the average weather-normalized electric sales over the prior three-year period.

Core Programs

Residential Lighting Program – NIPSCO implemented the Residential Lighting Program in May 2011. Discounts on General Electric Compact Fluorescent Lighting ("CFL") at retail stores vary in value between $1.20 - $2.50 per bulb based on bulb type, number of bulbs per pack, and retailer. The in-store markdown program is scheduled to run from May 2011 to November 2011. This administration of this program will transition to Good Cents, the third party administrator ("TPA"), in early 2012. At that time, a similar effort will be implemented.

Residential Low Income Weatherization Program – The Residential Low Income Weatherization Program will be implemented in 2012 and will be offered to low-income customers and includes a home energy audit along with the installation of energy efficiency measures at no cost to the customer. Measures may include weatherization, lighting, early removal of appliances, air sealing, refrigeration and air conditioner replacements.

Residential Home Energy Efficiency Audit Program – The Residential Home Energy Efficiency Audit Program was implemented in July 2011. The program is administered by Wisconsin Energy Conservation Corporation ("WECC") and is expected to transition to Good Cents, the TPA, in early 2012. The program provides residential customers with a home energy audit which identifies and recommends cost effective energy measures and also provides homes with low cost or no cost energy efficiency measures, such as CFLs and faucet aerators. Should the customer desire to install the recommended electric measures, they are referred to the Residential Core Plus Weatherization Program.

Energy Efficient Schools – The Energy Efficient Schools Program includes electric measures in kits provided to participating K-12 students for home use. The program also provides education regarding energy efficiency and is currently being administered by WECC. Program administration is expected to transition to Good Cents in the beginning of 2012, at which time it will be expanded to include a School Energy Efficiency Audits for K-12 schools. The audit will provide suggestions regarding various cost-effective energy efficiency measures. Should the school desire to install the recommended electric measures, they will be referred to the Core Commercial and Industrial Rebate Program as well as the Core Plus Commercial and Industrial Custom Program.

Commercial and Industrial Prescriptive Program - The Commercial and Industrial Prescriptive Program will offer cash rebates to commercial and industrial customers who purchase energy efficient light fixtures and ballasts as well as energy efficient pumps, motors and variable speed drives. Program administration will be provided by Good Cents and is expected to begin in early 2012. The program is designed to assist commercial and industrial customers in reducing electrical energy consumption and costs. The program will provide a prescriptive incentive structure that rewards with monetary incentives based on the installation of energy efficient equipment upgrades. The incentives will be provided for qualified one-for-one replacements, retrofits and new installations.

Core Plus Programs

Residential New Construction Program – The Residential New Construction Program was implemented in July 2011, and is administered by WECC. This program provides incentives for builders to build homes to the current ENERGY STAR home certification HERS score of 85 and 70. This program was designed to continue the incentive to builders while providing education about the new ENERGY STAR Homes requirements to mitigate market place confusion and encourage builders to continue focusing on building practices promoting energy efficiency. The second year of the program will be designed during the first year to address the new ENERGY STAR Homes Program requirements.

Residential Weatherization Program – NIPSCO implemented the Residential Weatherization Program in July 2011. WECC administers the program. The program is closely tied to the Core Residential Home Energy Audit Program which provides each participating customer with an audit to identify all electrical saving measures that exist for the customer. The customer is then referred to this Core Plus Residential Weatherization program, where an independent contractor provides the weatherization and other measures to be installed in the home. This program provides an upfront rebate to buy down the cost of the purchase to encourage the customer to move forward with the installation of the identified energy saving measures.

Residential Appliance Recycling Program – NIPSCO implemented Residential Appliance Recycling in August 2010. Appliance Recycling Centers of America ("ARCA") administers the program, bringing its experience from similar programs at other utilities. Customers are provided with a $35 incentive for each functioning refrigerator and freezer that is collected and recycled, up to a maximum of 2 units per year. ARCA removes the appliances disposes of them in an environmentally-compliant manner.

Residential and Non-Residential A/C Cycling Program – NIPSCO plans to implement Residential and Non-Residential A/C Cycling in the last quarter of 2011. Load control devices will be installed on central air conditioning units for residential and commercial customers rolled in the program. NIPSCO will use the control device to cycle central air conditioning compressors during summer peak periods and system emergencies. During the months of June through September, when either NIPSCO anticipates being close to its peak demand forecast and is exposed to high market prices, or when the MISO declares a system emergency, a wireless signal will be sent to the device that will cycle the air conditioner to 50 percent of the compressor's normal operating cycle. When electricity demand is reduced, the air conditioning unit will return to standard operation. The duration of each event will last no more than 4 hours. The program is open to all NIPSCO residential and commercial electric customers with air conditioning units of 5 tons or less.

Residential Direct Install Program – NIPSCO implemented Residential Direct Install Program in July 2011. The program is administered by WECC. Due to the current saturation of mixed- fuel multi-family homes, the program will transition to target all electric multi-family homes in the beginning of 2012 and will provide CFLs, high efficiency kitchen and bath aerators and showerheads in electrically water heated, residentially metered multifamily housing.

Residential Conservation Program – Residential Conservation Program was implemented in March 2011. The program provides specific and relevant energy efficiency recommendations to each participating customer, including information about other key energy efficiency programs offered by NIPSCO. This information helps customers act on recommendations and programs that are most relevant to them. The program provides more specific information and intervention to customers than traditional price signals. The main elements of the Conservation Program are direct-mailed Home Energy Reports and a web portal that includes a dashboard for each customer providing immediate access to information. The Conservation Program also includes a Customer Service Portal and periodic program reports to measure program performance.

The direct-mailed Home Energy Reports tailor energy efficiency recommendations for specific households and customer attributes that can be used for targeting are identified. Such attributes may include housing characteristics (e.g., presence of a pool, electric heating) as well as demographic characteristics (e.g., income level). Based on these customer attributes, the Conservation Program creates segments of customers who share certain attributes with each other so that specific measures can be targeted to the group.

The web portal will be a fully integrated component of the Home Energy Reporting Program, and, when coupled with the paper reports, will provide a unified, customizable customer experience. Every customer that will receive the Home Energy Reports will also receive access to the web portal. The web portal will include:

Neighbor Comparison – This enables customers to compare energy usage to their neighbors. This behavioral mechanism is proven to motivate further customer exploration of energy saving activities.

Actionable Insights – Customer data and actionable insights are available on the web portal. A dashboard highlights key savings opportunities, as well as improvement recommendations.

Targeted Tips – As in the paper Home Energy Reports, the dashboard features three targeted energy-saving recommendations based on the customer's usage and profile. Customer segment information that is stored in the system for a particular household is displayed across the top, allowing the customers to view or edit their information for maximum accuracy in analysis and recommendations.

NIPSCO currently has a three (3) year contract in place with Opower to execute this program during 2011, 2012, and 2013.

The per participant energy savings is expected to increase over time by program design. Reports are sent to the same set of customers over the 3-year execution period as long as the customer does not relocate or opt out of program participation. Due to natural attrition (participants moving and becoming naturally ineligible in terms of program requirements), participation is expected to decrease over time. Reports will be sent to participants on a quarterly basis, with an early distribution of consecutive reports at program launch. Program ramp-up is expected to produce sustained long-term savings. Due to the initial ramp-up in 2011, the early program savings are very conservative, estimated at approximately 1 percent. As the program is in place with the same participants over time, the program is expected to produce behavioral changes that result in higher savings in the range of 1.5 percent to 2.5 percent. The savings estimate in later years is still relatively conservative, expected to be in the range of 2.5 percent to 3.5 percent.

Total recipients receiving reports in the first three years of the program are:

Year 1 – 150,000 total recipients receiving reports
Year 2 – 137,560 total recipients receiving reports
Year 3 – 125,000 total recipients receiving reports

Approximately 1 percent of the program participants are expected to opt out of the program. Thirteen months of historical usage data at the same address is needed in order to qualify for participation in the program. If a selected participant moves to a new address at any time over the three year period, the participant would no longer be eligible at their new residence. Customers that fall out of eligibility would not be re-entered into the program in the future if eligible at a new residence. This is based on program design that restricts the addition of new customers driven primarily by the program budget and estimated MPS savings targets, rather than customer interest or market potential/constraints. This is an opt out program whereby customers are not required to actively participate or take any action.

Savings are defined as decreases in energy usage resulting from the behavioral changes attributed to reports that are uniquely-crafted for each participant. Reports are based on many factors, such as home age, participation in other DSM programs, home size. NIPSCO will provide customer data to Opower and Opower will analyze and engineer solutions. Reports will be sent to customers, and Opower will measure the changes in usage by participants as compared to a randomly selected control group of customers. The savings that can be directly traced to other factors or programs will be deducted from the savings that are claimed by Opower. Since gas savings are factored into the program, only gas/electric combo customers have been chosen to participate at this time.

Non-Residential New Construction Program – Non-Residential New construction Program was implemented in January 2011 and is administered by Franklin Energy. The program is designed to offer financial incentives to qualifying large commercial, industrial, non-profit, government and institutional customers for the completion of cost-effective electrical energy projects involving energy efficient property and equipment options for newly constructed facilities, existing facilities major renovations and additions to an existing facility. The program will provide or co-fund value-added services such as technical assistance studies through outside firms of the appropriateness and cost-effectiveness of identified technologies or design techniques, direct technical assistance to design teams, and commissioning services.

Non-Residential Custom Incentive Program – Non-Residential Custom Incentive Program was implemented in January 2011 and is administrated by Franklin Energy. The program targets unique efficiency opportunities for non-residential customers using a custom approach, including site-specific or specialty equipment upgrades. Technical assistance and other value-added service such as providing engineering studies to identify opportunities may be available through outside technical firms prequalified by NIPSCO. NIPSCO may provide this value-added service to support customers whose mission statement would not include the internal engineering resources to review the energy aspects of their operation. There are specific project caps in place to limit the amount of dollars applied per project as well as for each customer on an annual basis.

NIPSCO's DSM Promotional Activities/Communication Outreach

NIPSCO has recently elevated its internal emphasis on the development and promotion of various types of DSM programs for its residential, commercial and industrial customers. Over the past two years, NIPSCO has expanded its DSM staff and expertise in order to develop, evaluate and administer a robust portfolio of programs. NIPSCO's commitment to these programs has been demonstrated by the company's early implementation of the Residential Home Energy Efficiency Audit, Residential Appliance Recycling, and Residential Conservation program prior to Commission approval. NIPSCO has also enhanced its communication efforts with statewide stakeholders, including other governmental agencies, utilities and consumer parties in order to actively support and promote Energy Efficiency and DSM programs.

Demand Response and Interruptible

As part of the Commission's Order in Cause No. 43566-MISO 1, each of the jurisdictional electric utilities in Indiana was required to file a tariff or rider allowing industrial customers to take part in MISO demand response programs. NIPSCO garnered input from customers and potential customers before drafting the riders and throughout the process. The Company chose to offer Demand Response Resource ("DRR")-1-Energy Only and EDR-Energy Only programs because NIPSCO desires to offer programs where there is existing customer interest and the company has readily-available resources to assure a successful program. The DRR-1 program allows Customers to be compensated for providing a specific quantity of energy through load reduction to the energy market with NIPSCO serving as the market participant. In the EDR program, Customers may be compensated for providing a specific quantity of energy through load reduction or behind the meter generation to the energy market, with NIPSCO serving as the market participant, during a MISO declared emergency.

NIPSCO will continue to work with its customers to review such options and develop corresponding tariffs that would facilitate their participation. The Company expects to review such options after Customers have had the ability to participate and possibly incorporate any further options in time for the 2012-2013 MISO planning year. Additionally, as required by the Commission's Order in Cause No. 43566-MISO 1, NIPSCO will review the tariffs after two full summers of participation and will include participants and interested parties. NIPSCO will then submit a report to the Commission detailing the experience, costs and expenses associated with the Rider, along with details regarding the administrative charges collected. NIPSCO looks to add additional commercial and industrial Customers and plans to add a capacity program as customer interest and market forces permit.

In order to estimate the amount of interruptible load for 2010 and beyond, the proposed industrial interruptible rider was reviewed and analyzed. Given the parameters and relative price of the proposed interruptible service, a list of potential customer accounts with the capability of at least 5 MW of interruption was compiled and an estimate was made of the amount of the potential interruptible contract demand. This list was composed of twelve customers who qualified based on the 5 MW minimum. Up to 500 MW was utilized as the potential maximum interruptible load under contract.

Since the amount of interruptible service available under this proposed rider is the residual of the customer's total load and is dependent on the amount of firm service under contract, the next step was to estimate the amount of firm service that each customer would contract for, given the amount of their interruptible capability and their hourly load during 2008.

The amount of firm service was determined by analyzing each customer's load during 2008, and giving consideration to the provisions of the interruptible service rider along with the provisions under which a customer's firm billing demand would be determined under the proposed tariffs. The primary consideration is that the billing demand will be subject to various ratchets depending on historical maximum demands during the summer and non-summer periods and that their total load could be 10 percent to 20 percent above their firm contract demand, depending on the time and season, in which that customer would not establish a new firm contract demand.

Because the amount of capacity resources required for future years is dependent on NIPSCO's total firm load during the peak hours of the summer periods, it was necessary to estimate the amount of interruptible service that may be available. During the month of June through September, for the years 2009 through 2011, the total interruptible MW, as registered with MISO via the Module E Capacity Tracking Tool, has ranged from 85 MW to 252.2 MW. The plan uses 225 MW for an estimate at time of system peak.

Interruptible Services

NIPSCO registered 175 MW of interruptible load registered with MISO for the month of June through August 2011, and 90 MW for the month of September 2011. NIPSCO is committed to optimizing resources by offering interruptible service to better meet customers' needs. NIPSCO's electric rate case, Cause No. 43969, pending before the Commission, provides for the availability of an interruptible Rider for Customers that are taking service under proposed rates 632, 633, and 634. This Rider has the ability to impact peak demand because the Company may call an interruption when the applicable LMPs are in excess of the purchased power benchmark or curtail customers during times when MISO calls for decreases in load due to reliability situations on its system. In 2010, NIPSCO interrupted load four times, all for economic reasons because LMPs in the MISO energy market were projected to be high for the next several hours.

NIPSCO also has an interruptible service for residential, commercial and industrial customers through the Air Conditioning Cycling ("A/C Cycling") program. This program has the ability to reduce peak load by cycling residential, commercial and industrial air conditioning units during times of peak demand. NIPSCO will start marketing this program in November of 2011 with actual cycling set to begin in the summer of 2012. NIPSCO is committed to increasing DSM options for residential, commercial and industrial customers. It is anticipated that the A/C cycling program will continue to grow and that additional industrial customers will partake in the Interruptible Rider.

REVISED IRP
January 31, 2012
Indiana Utility Regulatory Commission

NiSource

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January 31, 2012

Via Hand Delivery
Ms. Brenda A. Howe
Secretary to the Commission
Indiana Utility Regulatory Commission
PNC Center, Suite 1500 East
101 West Washington Street
Indianapolis, Indiana 46204

Re: 2011 Integrated Resource Plan of Northern Indiana Public Service Company

Dear Ms. Howe,

In accordance with 170 IAC 4-7 ("IRP Rules") enclosed please find an original of Northern Indiana Public Service Company's ("NIPSCO") Supplement 1 to Section 5 – Existing Resources of its revised redacted biennial Integrated Resource Plan ("IRP") (Volume I), which was submitted to the Indiana Utility Regulatory Commission on January 24, 2011. A CD-Rom that includes an electronic version of Supplement 1 is also enclosed. Supplement 1 to Section 5 – Existing Resources of the IRP includes the information required by 170 IAC 4-7-4.16 (Explanation of the avoided cost calculation).

If you have any questions, please contact the undersigned.

Sincerely,

Claudia J. Earls

Enclosures

cc: Brad Borum (w/encl.)
A. David Stippler (w/encl.)

Supplement 1

This Supplement 1 to Northern Indiana Public Service Company's ("NIPSCO" or the "Company") revised redacted biennial Integrated Resource Plan ("IRP") Volume I, includes the information required by 170 IAC 4-7-4.16 (Explanation of the avoided cost calculation).

Avoided Generation Capacity Costs

A Combustion Turbine ("CT") is often the least cost technology to serve peak demand. To determine avoided generation capacity cost, the levelized annual economic carrying charge per kilowatt ("kW") of a new CT was calculated. A single year's economic carrying charge (avoided cost) is the cost avoided by delaying the purchases of an asset for one year. This approach can also be described as a deferral cost method where the avoided cost is equal to the difference between the present value of all capital and fixed costs for an asset commissioned in one year versus the following year. This is the same basic methodology described in 170 IAC 4-4.1-9 ("Rates for Capacity Purchase, Cogeneration and Alternate Energy Production Facilities"). For purposes of this analysis, NIPSCO used the Midwest Independent Transmission System Operator, Inc.'s ("MISO") required planning reserve margin of 5.35%. This was the required planning reserve margin at the time the avoided capacity costs were determined.

Avoided Transmission and Distribution Capacity Costs

In addition to the benefit of avoiding generation capacity costs, Demand-Side Management ("DSM") can also defer, and in some cases eliminate, future capital investments associated with transmission and distribution capacity. For transmission, the average capacity cost per kW was determined using the incremental amount of peak load (kW) associated with NIPSCO's load forecast, excluding wholesale and retail customers, whose service is taken at transmission level voltage. For distribution, the average capacity cost per kW was determined using the amount of load reduction (kW) that would be required to meet the distribution constraint.

The levelized annual economic carrying charge per kW was then calculated for a 40-year period. A single year's economic carrying charge (avoided cost) is the cost avoided by delaying an asset for one year. Program evaluation test were calculated for both with and without avoided distribution capacity costs.

Summary of Avoided Capacity Costs

Based on the methodology discussed above, NIPSCO's Avoided Capacity Cost used for the DSM programs filed in Cause No. 43912 is presented in Table S-1.

Table S-1

Year	Avoided Capacity Cost ($/kW stated at generation source)			Avoided Capacity Cost ($/kW at the Generator)	
	Generation Including Reserve Margin (Annual) (G)	Trans (Annual) (T)	Dist (Annual) (D)	Residential & Commercial (G)+(T)+(D)	Industrial (G)+(T)
2011	$82.21	$0.00	$28.26	$110.47	$82.21
2012	$84.45	$12.45	$29.22	$126.11	$96.90
2013	$86.74	$12.87	$30.21	$129.82	$99.62
2014	$89.11	$13.31	$31.23	$133.64	$102.42
2015	$91.54	$13.76	$32.28	$137.57	$105.29
2016	$94.03	$14.22	$33.37	$141.63	$108.25
2017	$96.60	$14.70	$34.50	$145.80	$111.30
2018	$99.23	$15.20	$35.67	$150.10	$114.43
2019	$101.94	$15.71	$36.87	$154.53	$117.65
2020	$104.72	$16.25	$38.12	$159.09	$120.97
2021	$107.59	$16.79	$39.41	$163.79	$124.38
2022	$110.53	$17.36	$40.74	$168.63	$127.89
2023	$113.55	$17.95	$42.12	$173.62	$131.50
2024	$116.65	$18.56	$43.54	$178.75	$135.21
2025	$119.85	$19.18	$45.01	$184.05	$139.03
2026	$123.13	$19.83	$46.54	$189.50	$142.96
2027	$126.50	$20.50	$48.11	$195.11	$147.00
2028	$129.97	$21.20	$49.74	$200.90	$151.16
2029	$133.53	$21.91	$51.42	$206.86	$155.44
2030	$137.19	$22.65	$53.16	$213.00	$159.84
2031	$140.95	$23.42	$54.95	$219.33	$164.37
2032	$144.82	$24.21	$56.81	$225.85	$169.03
2033	$148.80	$25.03	$58.73	$232.56	$173.83
2034	$152.88	$25.88	$60.72	$239.48	$178.76
2035	$157.09	$26.75	$62.77	$246.61	$183.84

Avoided Energy Costs

NIPSCO estimated avoided energy costs by using a forecast of future wholesale energy prices. The forecasted prices incorporate the cost of emissions and averaged into the costing periods. The resulting Avoided Energy costs for each cost period used for the DSM programs filed in Cause No. 43912 are provided in Table S-2.

Table S-2

Avoided Energy Costs

Forecasted $/MWh at the Generator

(Adjusted for no shoulder hours within a month for DSM ASSYST™)

	Annual		June - September		November - March		April, May and October	
Year	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
2010	$49.76	$33.94	$68.82	$36.03	$41.97	$34.10	$39.39	$19.02
2011	$50.61	$34.35	$70.12	$36.52	$42.77	$34.65	$39.76	$19.20
2012	$52.89	$35.20	$73.43	$38.12	$44.43	$34.95	$41.86	$20.34
2013	$55.25	$36.92	$75.82	$39.97	$47.52	$37.29	$42.80	$20.63
2014	$60.78	$39.75	$84.74	$43.07	$51.00	$39.94	$47.73	$22.59
2015	$68.32	$43.67	$95.82	$47.30	$56.81	$43.93	$53.87	$24.45
2016	$77.62	$48.78	$108.58	$52.77	$64.24	$49.10	$62.12	$27.64
2017	$84.23	$52.96	$116.86	$57.04	$70.52	$53.57	$67.17	$29.97
2018	$89.87	$56.96	$123.46	$61.94	$76.90	$57.76	$70.18	$32.10
2019	$96.26	$61.17	$133.28	$67.07	$81.43	$61.75	$75.55	$34.37
2020	$98.46	$62.14	$137.51	$66.76	$82.63	$62.93	$76.99	$35.01
2021	$96.75	$61.12	$134.60	$65.54	$80.99	$61.89	$76.72	$34.48
2022	$97.18	$62.21	$134.11	$66.23	$81.53	$63.19	$78.14	$35.18
2023	$101.64	$64.99	$141.31	$69.97	$84.41	$65.39	$81.95	$36.93
2024	$104.60	$67.95	$144.82	$74.28	$88.17	$68.40	$82.70	$38.23
2025	$107.04	$70.05	$147.05	$74.56	$90.82	$71.18	$85.05	$39.97
2026	$110.01	$71.86	$152.17	$76.31	$92.47	$72.90	$87.65	$40.43
2027	$114.43	$74.42	$157.74	$78.74	$96.13	$75.86	$92.00	$41.78
2028	$115.38	$75.68	$156.39	$79.03	$97.80	$77.17	$94.62	$43.32
2029	$117.78	$77.17	$162.21	$83.73	$99.71	$77.57	$93.45	$43.95
2030	$120.61	$79.16	$165.96	$85.78	$102.19	$79.56	$95.78	$45.20
2031	$123.52	$81.21	$169.79	$87.88	$104.74	$81.59	$98.16	$46.48
2032	$126.49	$83.30	$173.72	$90.03	$107.35	$83.68	$100.61	$47.80
2033	$129.54	$85.45	$177.73	$92.23	$110.03	$85.82	$103.12	$49.16
2034	$132.65	$87.66	$181.84	$94.49	$112.78	$88.02	$105.69	$50.55
2035	$135.85	$89.92	$186.04	$96.80	$115.59	$90.27	$108.33	$51.99
2036	$139.12	$92.24	$190.34	$99.17	$118.47	$92.58	$111.03	$53.46
2037	$142.47	$94.62	$194.73	$101.59	$121.43	$94.94	$113.79	$54.98
2038	$145.90	$97.06	$199.23	$104.08	$124.45	$97.37	$116.63	$56.54
2039	$149.41	$99.56	$203.83	$106.62	$127.56	$99.86	$119.54	$58.15

SECTION 6: LOAD AND RESOURCE ANALYSIS

NIPSCO

Highlights – Load and Resource Analysis

- ***Load and Resources assessed for the NIPSCO Service Territory***
- ***Potential Resource Portfolio adjustments identified***
- ***Identified shortfalls are minor; reliability not threatened.***

Analysis of Resources

In Table 6-1 below is the assessment of NIPSCO's existing resources (Unforced Capacity ("UCAP")) against the future needs from the demand forecast (Internal Peak).

Table 6-1

Assessment of Existing Resources vs. Demand Forecast

	(a)	(b)	(c)	(d)	(e)	
Year	**Unforced Capacity (UCAP)**	**Internal Peak (FP07a11)**	**Interruptible (MW)**	**Internal Peak Minus Interruptible (MW)**	**Internal Peak Minus Interruptible Plus Reserve Margin (MW)**	**Capacity Position Long/Short (MW)**
				(b) - (c)	(d) x 1.0381	(a) - (e)
2011	3,085	3,127	175	2,952	3,064	21
2012	3,098	3,214	225	2,989	3,103	5
2013	3,112	3,299	225	3,074	3,191	79
2014	3,104	3,307	225	3,082	3,200	96
2015	3,104	3,320	225	3,095	3,213	109
2016	3,104	3,314	225	3,089	3,207	103
2017	3,104	3,293	225	3,068	3,185	81
2018	3,104	3,272	225	3,047	3,163	59
2019	3,104	3,247	225	3,022	3,137	33
2020	3,092	3,222	225	2,997	3,111	20
2021	3,092	3,269	225	3,044	3,159	68
2022	3,092	3,310	225	3,085	3,202	110
2023	2,931	3,344	225	3,119	3,238	306
2024	2,931	3,383	225	3,158	3,279	347
2025	2,931	3,423	225	3,198	3,320	389
2026	2,931	3,465	225	3,240	3,363	432
2027	2,931	3,509	225	3,284	3,409	477
2028	2,931	3,565	225	3,340	3,467	536
2029	2,597	3,617	225	3,392	3,521	924
2030	2,597	3,670	225	3,445	3,576	979
2031	2,597	3,732	225	3,507	3,641	1,044
2032	2,597	3,796	225	3,571	3,707	1,110

Notes:

1. Internal Peak and Interruptible for 2011 reflect actual.
2. Reserve Margin for 2011 - 2032 is 3.81%
3. UCAP reflects units retiring after the peak season in the years - 2013, 2019, 2022, and 2028
4. Wind Contracts are not included in UCAP
5. UCAP is a NIPSCO estimated value

In Table 6-1, Column (e) is the result of Internal Peak minus Interruptible plus the MISO Planning Reserve Margin of 3.81 percent. Capacity Position is therefore calculated by subtracting Column (e) from Column (a).

Section 7 - Resource Alternatives covers the resources options NIPSCO evaluated to bridge any capacity and energy gap. Section 9 - Resource Alternatives Analysis discusses how NIPSCO integrates those options with the existing resources. NIPSCO is committed to meet our customers' electrical needs with safe, reliable and affordable energy.

SECTION 7: RESOURCE ALTERNATIVES

NIPSCO

Highlights – Resource Alternatives

- ***Full suite of self-build supply-side options assessed.***
- ***Detailed analysis of feasible gas and coal prototypes.***
- ***Burns & McDonnell engineering study provides closer assessment of resource costs and assumptions***
- ***Planning criteria: Safety, Reliability, Adequacy, Cost.***

NIPSCO evaluates a variety of resources to determine the optimal portfolio to serve customers' future needs.

Resource Options Evaluated

NIPSCO's 2009 IRP identified no need for additional capacity and energy in the short-term. NIPSCO's 2009 IRP recommended short-term capacity purchases from the market and did not project a need for capacity until 2015.

In developing NIPSCO's 2011 IRP only self-build supply-side options were considered. Demand-side options were reviewed in Cause No. 43912 as discussed earlier. Without a short-term requirement for new capacity and energy, a full evaluation of market options would be premature. The intent of NIPSCO's 2011 IRP is to address NIPSCO's current resource requirements through self-build options and if the Short-Term Action Plan identifies a need for new capacity and energy, NIPSCO will evaluate market options in a separate RFP. One significant factor from the 2009 IRP continues to affect NIPSCO's 2011 IRP; the prolonged economic downturn has substantially lowered NIPSCO's forecast for demand and energy.

Supply-Side Options

The analysis of Self-Build Options considered a full range of traditional gas and coal prototypes. In the NIPSCO's 2011 IRP process, the evaluation of Self-Build Options also considered nuclear prototypes and a full range of renewable resource prototypes. NIPSCO commissioned an engineering study from the engineering firm Burns & McDonnell ("Study"). The Study evaluated Self-Build Options for NIPSCO's long-range planning, and developed the costs and operating assumptions for various resources. The range of resources reviewed included:

NATURAL GAS

- Simple Cycle Combustion Turbines ("CT_7FA") – Greenfield & Brownfield
- Simple Cycle Combustion Turbines Aeroderivative ("CT_Aero") – Greenfield & Brownfield
- Combined Cycle – Greenfield & Brownfield
- Combined Cycle Conversion

COAL & NUCLEAR

- Supercritical Pulverized Coal ("PC")
- Integrated Gasification Combined Cycle ("IGCC")
- Nuclear Advanced Pressurized Water Reactor

RENEWABLE

- Biomass Bubbling Fluidized Bed
- Wind (Onshore & Offshore)
- Solar Photovoltaic
- Geothermal

ENERGY STORAGE

- Battery Storage
- Flywheel
- Pumped Hydroelectric Plant
- Compressed Air Energy Storage
- Superconducting Magnetic Energy Storage

NIPSCO's Self-Build Supply-Side Resource Analysis

NIPSCO based the cost of Self-Build Supply-Side resources on estimates provided by Burns and McDonnell in April 2011.

NIPSCO focused its Self-Build Supply-Side resource opportunities for inclusion in the 2011 IRP on widely available, commercially and technologically mature options in order to reduce the opportunity for cost escalation or failure. The technologies analyzed for Self-Build Supply-Side incremental resources opportunities were Supercritical PC, Nuclear Advanced Pressurized Water Reactor ("Nuclear"), IGCC, CCGT, CT_7FA, and CT_Aero. The CC, CT_7FA, and CT_Aero analysis included two configurations, Brownfield and Greenfield development. These options are summarized in CONFIDENTIAL Appendix F, Table F-1.

The NIPSCO Self-Build Supply-Side options were initially evaluated using a levelized cost screening to determine which options would be preferred for the peaking, intermediate, and base load operating cycles, i.e., capacity factor. The results of this screening are expressed in levelized $/kW-yr. for various capacity factor levels and are shown in Figure 7-1. These values include all capital construction and associated costs as well as fixed and variable operating and maintenance ("O&M") costs, and fuel costs. The capital costs include overnight construction costs, property taxes and insurance, and transmission interconnection costs. Capital construction costs at a rate of 3 percent annual escalation rate, a before tax weighted cost of capital of 8.47 percent, an AFUDC rate of 7.56 percent, and a discount rate of 7.55 percent. Transmission system upgrade costs associated with these generic resources are not included since the estimates were not site specific. Variable costs include variable O&M costs, fuel costs, and all associated emissions costs (SO_2, NO_x and CO_2). Long run fuel prices escalations are 2.54 percent for PRB coal, 2.54 percent for Illinois Basin coal, and 6.29 percent for natural gas. Variable and fixed O&M costs are assumed to escalate at 1.80 percent over the long term.

Figure 7-1
Utility Self-Build Screening Curves

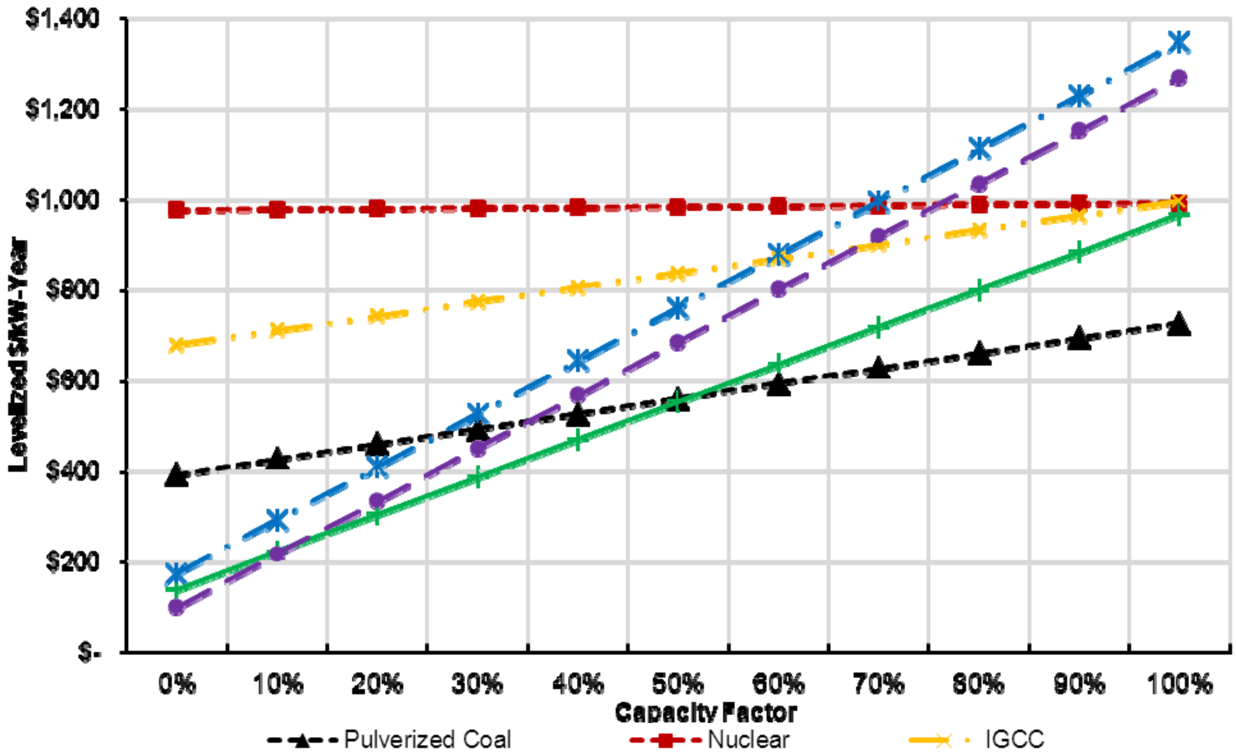
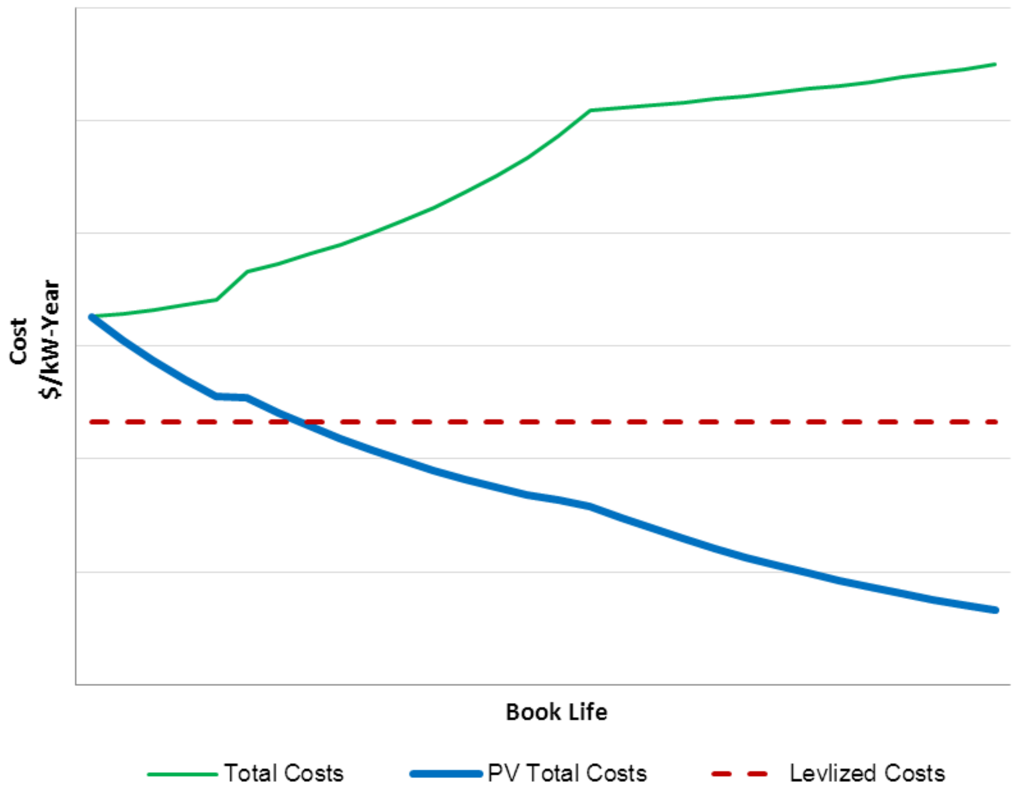


Figure 7-1 is a Screening Curve of the Self-Build Supply-Side options under consideration. The horizontal axis is capacity factor. The horizontal axis is the independent variable that defines how much the unit operates from 0 percent to 100 percent. The vertical axis is the levelized cost, in $/kW-Year. The levelized cost represents the present value of the total cost of building and operating a generating plant over its book life, converted to equal annual payments and amortized over the expected annual generation from an assumed duty cycle, or capacity factor. Figure 7-2 generalizes the levelization process.

Figure 7-2
Levelized Cost Example



The CT_7FA is economic for a capacity factor from 0 percent to 10 percent. The CCGT is economic from a capacity factor from 10 percent to 50 percent. The PC is economic for a capacity factor greater than 50 percent. Based on these results, the optimal plan will contain some combination of CCGT, CT_7FA and PC technologies. The remaining technologies will be included in the sub-optimal plans. All of the Self-Build Supply-Side options were carried forward into the Supply-Side and Demand-Side Integration phase of the IRP as potential Self-Build Supply-Side alternatives. In addition, NIPSCO included a conversion of two CT_7FA to a CCGT.

Construction lead times are an important consideration. The construction lead times and the first year that a resource could be added are shown in Table 7-1.

Table 7-1
Utility Self-Build Construction Lead Times

	PC	Nuclear	IGCC	CC	CT_Aero	CT_7FA
Construction Lead Time (years)	10	10	7	5	2	3
First Year Available	2021	2021	2018	2016	2013	2014

NIPSCO's Self-Build Renewable Resource Analysis

NIPSCO based the cost of Self-Build renewable resources on estimates provided by Burns and McDonnell in April 2011.

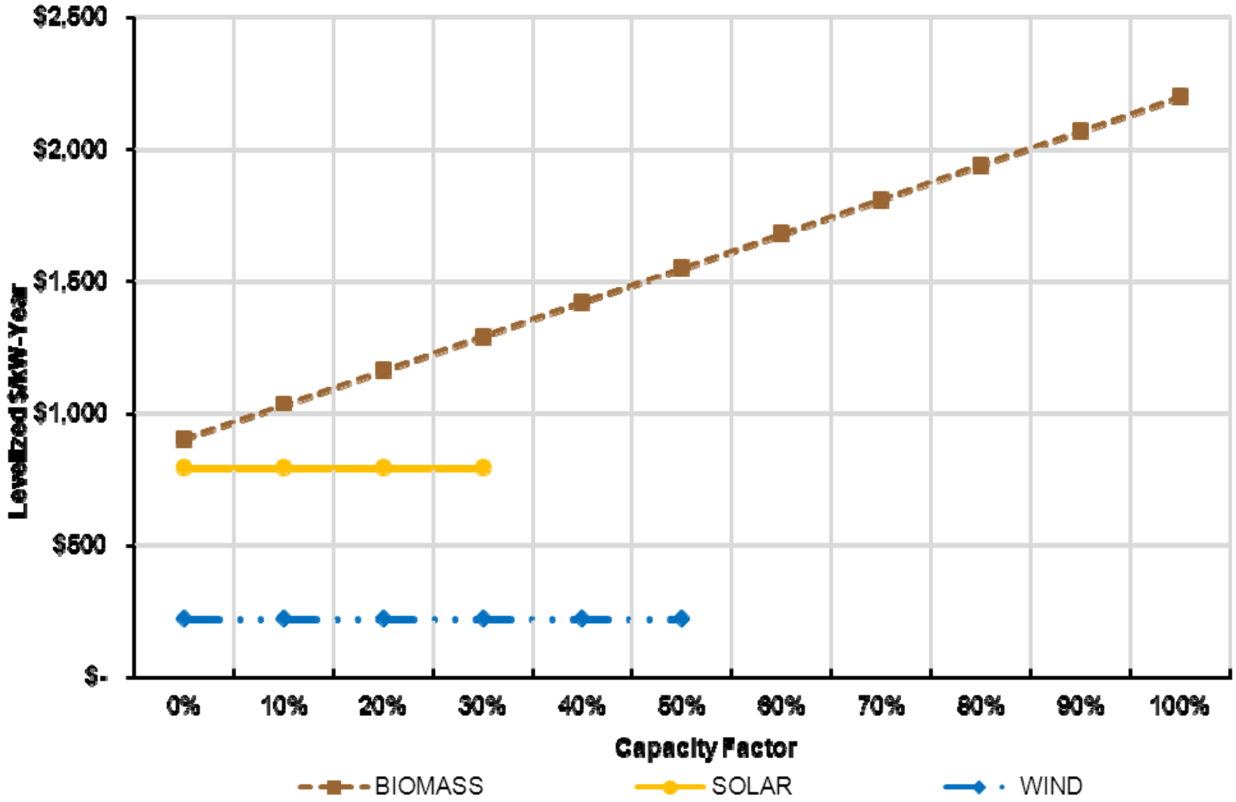
The scope of renewable technologies included: Biomass, On-Shore Wind, Off-Shore Wind, Solar Photovoltaic, and Geothermal. Geothermal was eliminated because the NREL has classified Indiana as having the least favorable temperature conditions for geothermal resources. Off-shore Wind was eliminated due to the cost advantages of On-Shore Wind. NIPSCO focused its Self-Build Renewable resource opportunities for inclusion in the 2011 IRP on widely available, commercially and technologically mature options in order to reduce the opportunity for cost escalation or failure. The technologies analyzed for Self-Build Renewable incremental resources opportunities were Biomass, Solar and Wind. The Self-Build Renewable resources are summarized in CONFIDENTIAL Appendix F, Table F-2.

The NIPSCO Self-Build Renewable options were initially evaluated using a levelized cost screening to determine which options would be preferred for the peaking, intermediate, and base load operating cycles, i.e., capacity factor. The results of this screening are expressed in levelized $/kW-yr. (2011$) for various capacity factor levels and are shown in Figure 7-3. These values include all capital construction and associated costs as well as fixed and variable O&M costs, and fuel costs. These values include all capital construction and associated costs as well as fixed and variable O&M costs, and fuel costs. The capital costs include overnight construction costs, property taxes and insurance, and transmission interconnection costs. Capital construction costs assume a 3 percent annual escalation rate, a before tax weighted cost of capital of 8.47 percent, an AFUDC rate of 7.56 percent, and a discount rate of 7.56 percent. Transmission system upgrade costs associated with these generic resources are not included since the estimates were not site specific.

NIPSCO's anticipates that production tax credits for renewable generation are not likely to be extended into 2013. In support of this forward view, Self-Build Renewable options are evaluated without the benefit of production tax credits or accelerated depreciation. NIPSCO has evaluated the economic ranking of renewable technologies with and without production tax credits and accelerated depreciation. These tax benefits do not affect the economic ranking of the relative technologies.

The Wind and Solar renewable options have no variable operating expenses. The Biomass renewable option does include a variable O&M expense escalating at 1.80 percent over the long term. The Biomass renewable option uses regenerative organic material for energy production. Biomass fuel typically consists of forestry materials, wood residues, agricultural residues, and energy crops. NIPSCO used a price of $5/MBTU (2011$) to price the expected quantities of agricultural commodity crops available for biomass. Biomass fuel costs escalate at 1.80 percent over the long term. The feasible operating range for Biomass is from a 0 percent to 100 percent capacity factor, Solar is from a 0 percent to 30 percent capacity factor, and Wind is from 0 percent to 50 percent capacity factor.

Figure 7-3
Utility Self-Build Renewable Screening Curves



The wind is economic for a capacity factor from 0 percent to 50 percent. Biomass is the only technology available beyond a 50 percent capacity factor. Based on these results, the optimal plan will contain some combination of wind and biomass technologies. However, the energy requirements for renewable are not expected to be greater than a 50 percent capacity factor. NIPSCO tested the sensitivity of the assumed fuel price for biomass. A zero biomass fuel costs do not improve the economic value of biomass. The wind option was carried forward into the Supply-Side and Demand-Side Integration phase of the IRP as potential Self-Build Supply-Side Renewable alternatives.

Construction lead time is an important consideration. The construction lead time and the first year that a resource could be added are shown in Table 7-2.

Table 7-2
Self-Build Renewable Construction Lead Times

	BioMass	Solar	Wind
Construction Lead Time (years)	4	4	3
First Year Available	2015	2014	2014

Market-Based Options

The Company did not undertake a comprehensive review of market options. In previous IRP filings, the Company began the IRP process with an identified short-term need for capacity and energy. NIPSCO intends to use the results of the 2011 IRP as the basis for a future RFP to fully evaluate the market options available, when a short-term need for capacity and energy is required.

Expansion Planning Criteria

The 2011 IRP involved a comprehensive assessment of the generation expansion planning criteria to determine what level of capacity is necessary to serve customers safely, reliably and adequately at the lowest reasonable cost. These criteria, among others, assisted in screening the pool of available resource options.

Planning Reserve Margin - A minimum Planning Reserve Margin will ensure a minimum level of resource adequacy. The MISO Unforced Capacity ("UCAP") planning protocol was used. To ensure that the correct criteria was employed, the Company constrained the 2011 IRP optimization so that no resource mix would be accepted that achieved a Planning Reserve Margin of less than 3.81 percent for years 2012 to 2032. Based upon NIPSCO's generation fleet reliability, MISO's targeted UCAP planning reserve margin of 3.81% is roughly equivalent to a traditional Planning Reserve Margin of 9 percent to 12 percent using the Installed Capacity planning protocol.

An adequate minimum Planning Reserve Margin will minimize loss of load hours and the system's reliance on emergency energy. Maximum Planning Reserve Margin constraints for the optimizations were set between 30 percent and 40 percent, annually across the study horizon. These constraints are non-binding. This maximum Planning Reserve Margin constraint is high enough to allow the addition of large resources, but not so high as to permit overbuilding.

Economically Ranking Competing Plans - A minimization of Net Present Value Revenue Requirements ("NPVRR") criterion was used in the Strategist® model for economically ranking competing plans from the optimization. NIPSCO modeled the assumption that after $7.9 million of off-system revenues, incremental revenues are shared 50/50 between NIPSCO customers and NIPSCO shareholders.

Siting Issues and Related Constraints - The Company evaluated both a brownfield development and a greenfield development. The existing Sugar Creek facility has sufficient infrastructure to accommodate two additional brownfield CT's or one additional brownfield CCGT. Furthermore, the NIPSCO evaluation team modified the technology assessment to accommodate a CT to CCGT project. Once two CT_7FA are developed, an option to convert to a CCGT was evaluated.

The planning criteria also involved a technology assessment of Supply-Side generating resources. The technology assessment evaluated whether the Supply-Side resource had certain technology adaptive characteristics. For instance, NIPSCO sought to ensure that the selected resource technology is commercially available in order to maximize reliability and price certainty. Commercially mature technologies were preferred, see Table 7-3. NIPSCO preferred resources that promoted fuel diversification and fuel transportation diversity to engage a diverse and balanced range of fuels while maintaining economic flexibility and avoiding undue reliance. NIPSCO also considered operational flexibility, such as those that offer automatic generation control ("AGC") and black start capability, along with the greatest degree of scheduling flexibility. See CONFIDENTIAL Appendix H.

Table 7-3
Generation Technology Database

Description	Simple Cycle GT	CCGT	Supercritical PC	IGCC[1]	Wind Generation
Source	Vendor	Vendor	Vendor	Vendor	Vendor
Technology Development Rating	Mature	Mature	Mature	Mature	Mature
Cost Estimate Rating	Engineering	Engineering	Engineering	Engineering	Market Base
Significant Solid Waste Disposal	None	None	Potential	Potential	None
Significant Hazardous Waste and Disposal	Negligible	Minimal	Minimal	Minimal	None
Fuel Type	Natural Gas	Natural Gas	Coal	Coal	Wind

[1] The IGCC Unit is assumed to be a 1x1x1 configuration

In addition, the 2011 IRP planning criteria incorporated several financial goals to promote a thorough resource evaluation and selection process. Topmost among these were cost effectiveness which would be achieved by securing a portfolio of reasonable least cost assets. The plan minimizes the Net Present Value ("NPV") of NIPSCO's generation-related revenue requirement over the time period of 2011 through 2032. The 2011 IRP also promotes resources that would provide rate stabilization and would minimize the impact of large capital additions on customer rates. The 2011 IRP goals focus on the ability to balance interests between the Company's interest in securing reliable generating facilities that contribute to its opportunity to earn its allowed return and its customers' interests in lowest reasonable cost electricity service. The 2011 IRP promotes price certainty by securing a robust portfolio of Self-Build Supply-Side alternatives. Finally, the 2011 IRP minimizes volatility by looking for opportunities to reduce fuel and energy market volatility.

The 2011 IRP also defines a resource attributes list used for screening the supply-side options. The first attribute is reliability. Under this standard, each resource in the plan must reflect a minimum amount of secured capacity to meet projected summer peak demands, associated energy needs, and the provision of adequate planning reserves per year over the time period of 2011 through 2032. The second attribute is ancillary services that would permit NIPSCO to maximize reliability and minimize cost by securing resources that would be capable of contributing to the overall reliability of the NIPSCO and MISO systems. As further defined, resources which reflected maximum flexibility and provision of the following ancillary services: (1) reactive power; (2) contingency reserves/quick start capability; (3) spinning reserves; and (4) black start capability met the identified reliability attribute. The third measurement criterion is the evaluation of congestion and marginal losses to minimize the impact of congestion and marginal losses between the resource's location/delivery point and the NIPSCO load zone.

2011

SECTION 8: ENVIRONMENTAL CONSIDERATIONS

NIPSCO

INTEGRATED RESOURCE PLAN

Highlights – Environmental Considerations

- ***NIPSCO is committed to ongoing environmental compliance.***
- ***NIPSCO's Multi-Pollutant Compliance Plan is based on EPA Consent Decree, the EPA Clean Air Transport Rule ("CATR", CSAPR) and Utility MACT Rule.***
- ***Compliance requires substantial investments in NIPSCO's generation fleet***
- ***Compliance timeline 2012 - 2018***
  CATR/CSAPR: reduction of SO_2 and NO_x emissions begins in 2012; further reductions in 2014.
  Proposed Utility MACT compliance by 2016.
  Transport Rule (SO_2 and NO_x) emissions compliance by 2018.
  National Ambient Air Quality Standards (SO_2) compliance by 2017 – 2018.

Environmental Compliance Issues

NIPSCO is committed to complying with all Environmental, Health and Safety, legal, and other regulatory requirements affecting health, safety and the environment. This commitment is embodied in the NIPSCO Environmental Policy and is implemented through an environmental management system. NIPSCO closely follows changes in laws and regulations and develops and implements programs to address the laws and regulations. Compliance plan options are developed, reviewed and evaluated for implementation to meet new legislative and regulatory developments. In the following paragraphs, NIPSCO discusses each of the complex environmental issues.

Environmental Issues Affecting NIPSCO Generation

Environmental Issues Affecting NIPSCO Generation

- *Climate Change*
- *GHG Emissions Control and Reporting*
- *National Ambient Air Quality Controls*
- *Acid Rain SO_2 Reduction*
- *Regional Pollutant Transport NOx, SO_2 and Hg Emissions Reductions*
- *Consent Decree*
- *Clean Water Act Discharge Regulations*

Climate - Existing climate related environmental laws and regulations may be revised and new laws and regulations seeking to protect the environment may be adopted or become applicable to NIPSCO. Revised or additional laws and regulations could result in significant additional operating expense and restrictions on NIPSCO's facilities and increased compliance costs. Moreover, such costs could affect the continued economic viability of one or more of NIPSCO's facilities.

Because NIPSCO operations involve the use of natural gas and coal fossil fuels, emissions of GHG are inherent in the business. While NIPSCO attempts to reduce GHG emissions through efficiency and other programs, GHG emissions cannot be entirely eliminated. The current administration has targeted reductions in GHG emissions first through legislation that ultimately did not pass and then through regulation. Imposing statutory or regulatory restrictions on GHG emissions could increase NIPSCO's cost of producing energy, which could impact customer demand and customer costs. Compliance costs associated with these requirements could also affect NIPSCO's cash flow. The cost impact of any new or amended GHG legislation or regulations would depend upon the specific requirements enacted.

The debate continues in the U.S. about the scope of federal, regional and state programs to manage GHG emissions. Federal regulations have been recently proposed and are being further developed. These regulations are primarily focused on mandatory emissions reporting. NIPSCO has been active in various forums including with trade associations representing electric companies to help shape potential regulations. NIPSCO has participated with the Edison Electric Institute to engage in the discussion on the climate change legislation and regulation. In addition, NIPSCO has discussed legislative proposals with both Congressional staff and EPA staff.

At this time it does not appear likely that widespread GHG reductions will be required until, at a minimum, the latter half of this decade. NIPSCO is estimating that a price on carbon will not be established prior to 2020 due to the current economic and political environment, in addition to the time required for a widespread program to be developed and implemented.

EPA GHG Mandatory Reporting Rule - The EPA finalized the GHG Mandatory Reporting Rule in 2010. The rule, which went into effect in the spring of 2010, requires GHG emitters such as NIPSCO to inventory and report emissions of GHGs. Initial reporting will be submitted in 2011 for combustion sources and distribution systems and in 2012 for fugitive and vented emissions. The program will result in EPA's first comprehensive GHG emissions inventory generated completely from individual source's publicly reported emissions estimates.

GHG Tailoring Rule - The EPA implemented the GHG Tailoring Rule in 2011. This rule requires States to implement requirements in Title V permits to address GHG pollutants. This rule requires implementation of BACT technology for new or modified sources to control GHG emissions and can result in longer permit timelines. New construction and modifications which have emissions increases exceeding 75,000 ton per year carbon dioxide equivalent ("CO_2e") will require NSR pollutant evaluation and reporting in 2011. Sources less than 50,000 ton per year CO_2e will not be addressed until 2016.

Clean Air Act ("CAA")

NIPSCO expects a number of new air-quality mandates to be phased-in over the next several years. These mandates will require NIPSCO to make capital improvements to its electric generating stations.

National Ambient Air Quality Standards ("NAAQS") - The CAA requires the EPA to set national air quality standards for particulate matter ("PM") and five other pollutants (the NAAQS) considered harmful to public health and the environment. The EPA imposes new, or modifies existing, NAAQS periodically and requires states that contain areas that do not meet the new or revised standards to take action toward achieving compliance with the standards through the use of local or regional based emission control measures. These actions could include adding pollution controls on facilities owned by electric generation.

The following NAAQS were recently added, modified, or are in the process of being revised:

- Ozone NAAQS
  Indiana Department of Environmental Management ("IDEM") submitted a petition to the EPA seeking redesignation of Porter County, home to Bailly, to attainment of the ozone NAAQS. The EPA approved the request on May 11, 2010.

- Reconsideration of 8-hr Ozone NAAQS
  On March 12, 2008, the EPA announced the tightening of the eight-hour ozone NAAQS. The EPA has not yet announced the classification structure and the corresponding attainment dates for the new standard. Additionally, on September 16, 2009, the EPA announced it would reconsider the March 2008 tightening of the ozone NAAQS and, if necessary, promulgate more stringent standards. The EPA announced it planned to finalize the standards by July 2011 but has decided not to finalize the rule. On September 2, 2011, at the request of President Obama, the EPA announced that it will not issue a rule for reconsideration of the 2006 ozone standard. The EPA will wait until the standard review cycle and issue an updated ozone standard in 2013. If the standards are tightened later and area designations are subsequently changed to nonattainment, the states will need to develop a new State Implementation Plan ("SIP") within three years to bring those areas into compliance.

  If the EPA lowers the ozone NAAQS, Porter County and LaPorte County, home to Bailly and Michigan City, could be redesignated back to nonattainment. As noted in Tables 4-2 and 4-3, NIPSCO has already installed OFA and SCR to control NO_x emissions on each of the generating units located at Bailly and Michigan City.

- SO_2 NAAQS
  On December 8, 2009, the EPA revised the SO_2 NAAQS by adopting a new 1-hour primary NAAQS for SO_2. The EPA expects to designate areas that do not meet the new standard by mid-year 2012. States with such areas, including Indiana, would have until 2014 to develop attainment plans with compliance required by 2017. IDEM submitted initial designation recommendations to the EPA in June 2011. IDEM is seeking "unclassifiable" designations for counties in which NIPSCO has coal-fired generating stations and is in the process of conducting further air quality evaluations prior to EPA finalization of the designations. As part of its additional analyses, IDEM is in the process of evaluating air quality monitoring data and performing air quality modeling per EPA requirements. NIPSCO's Multi-Pollutant Compliance Plan ("MPCP") includes installation of three new scrubbers, resulting in all of its coal units being scrubbed.

- PM NAAQS
  In 2006, the EPA issued revisions to the NAAQS for PM. The final rule (1) increased the stringency of the current fine particulate (PM2.5) standard, (2) added a new standard for inhalable coarse particulate (PM between 10 and 2.5 microns in diameter), and (3) revoked the annual standards for coarse particulate (PM10) while retaining the 24-hour PM10 standards. These actions were challenged in a case before the D.C. Court of Appeals, *American Farm Bureau*

Federation et al. v. EPA. In 2009, the appeals court granted portions of the plaintiffs' petitions challenging the fine particulate standards but denied portions of the petitions challenging the standards for coarse particulate. State plans implementing the new standard for inhalable coarse particulate and the modified 24-hour standard for fine particulate are expected in 2012. The annual and secondary PM2.5 standards have been remanded to the EPA for reconsideration.

In 2008, IDEM submitted a request to the EPA seeking redesignation of Lake and Porter counties to attainment of the annual fine PM standard. The EPA had not acted upon the request due to concerns about whether emission reduction requirements across the eastern United States under the CAIR would remain in place. As a result, IDEM recently sent EPA an update of the 2008 request. On September 27, 2011, with the Clean Air Transport Rule ("CATR"), now the CSAPR, finalized in July, 2011, the EPA proposed approving the request.

Acid Rain Program – The CAA Amendments of 1990 introduced a new nationwide approach to reduce the emission of acidic air pollutants. The Acid Rain program was designed to reduce electric utility emissions of SO_2 and NO_x through a market based cap and trade system. While the SO_2 reductions were achieved in two phases by the establishment of lower overall emissions caps, NO_x emission controls were required using a two phased control technology based emission reduction program.

Regional Pollutant Transport Requirements - The EPA has determined that, for purposes of achieving ozone and particulate attainment, emissions from certain upwind states, including Indiana, 'contribute significantly' to downwind state nonattainment areas. As a result, the NOx SIP Call (Call being the EPA requirement, or call, for individual states to develop SIPs to reduce NO_x emissions) and CAIR regional emission control programs were developed to address regional pollutant transport issues and are more fully described below. Emission reductions from NIPSCO generating stations have been identified to address both local nonattainment as well as regional pollutant transport issues.

- EPA NO_x SIP Call
  In December 2001, the EPA approved regulations developed by the State of Indiana to comply with the EPA's NO_x SIP Call. The NO_x SIP Call requires certain states, including Indiana, to reduce NO_x emissions during the ozone season (May 1 through September 30) from source categories including industrial and utility boilers. Compliance with the NO_x limits contained in these rules was required by May 31, 2004. To comply, NIPSCO developed a NO_x compliance plan, which included the installation of SCR and combustion control NO_x reduction technology at its active generating stations and is currently in compliance with the NO_x requirements.

- CAIR
  On March 10, 2005, the EPA finalized the CAIR, which established a phased reduction program of SO_2 and NO_x emissions in the eastern United States beginning in 2009 for NO_x and 2010 for SO_2. CAIR established an annual emissions cap for SO_2 and NO_x emissions and allowed for the regional trading of both SO_2 and NO_x allowances. On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the CAIR entirely; however, on December 23, 2008, the court decided to remand the CAIR, without vacatur, to the EPA to remedy the rule's flaws identified in the July 11, 2008 ruling. As a result of this December 23, 2008 ruling CAIR remains in effect until its replacement becomes fully effective. Electric utilities within the CAIR region, including those in

Indiana, began complying with the CAIR NO_x reduction targets on January 1, 2009 and the SO_2 targets on January 1, 2010.

- CSAPR, formerly the CATR

  On July 6, 2010, the EPA proposed the CATR to address the court's concerns over the CAIR. The CATR was scheduled to replace CAIR beginning in 2012, and address electric generating unit ("EGU") SO_2 and NO_x emissions in 32 eastern states, including Indiana. On July 7, 2011, the EPA announced it finalized the rule and renamed it the CSAPR. This replacement for CAIR was published in the *Federal Register* on August 8, 2011, and became effective on October 7, 2011, with compliance beginning in January 2012. Like the CATR, the CSAPR is established as a Federal Implementation Plan ("FIP") and also creates a process for states to replace the FIP with their own SIP as soon as 2014. Under a SIP, Indiana may alter the sources included in the program as long as total state emission reductions are equivalent to those in the FIP. On August 25, 2011, IDEM took the first step in the Indiana rule making process to create such a SIP and published the first notice of Proposed Rulemaking in the *Indiana Register*.

  Like the CATR, the CSAPR establishes an aggressive timetable for implementing SO_2 and NO_x emission reductions but revised the number of states in the program to twenty-seven (27), including Indiana. The first phase of the emission reductions in all 27 states begins in 2012 and in 2014 the second phase will further reduce SO_2 emissions in 16 states including Indiana. The EPA projects that by 2014, CSAPR will reduce SO_2 emissions in the 27 states by 73 percent from their 2005 levels, while EGU NO_x emissions are projected to be reduced by 54 percent from 2005 levels. Unlike CAIR, CSAPR's preferred approach allows for emission allowance trading, but places limitations on the amount of allowances that could be traded within the four trading programs. Specifically, the CSAPR establishes four separate trading programs: two for annual SO_2, one for annual NO_x, and one for ozone season NO_x. The CSAPR also establishes two categories of units, defined by the impact of SO_2 emissions from the geographic area as determined by air quality modeling. Specifically, Group 1 and Group 2 units differ because the former are subject to the more stringent Phase II SO_2 emissions reduction requirements in 2014, and the latter remain subject to less stringent 2012 requirements.

  Unlike CAIR, the CSAPR trading program does not allow for the carry-over of any other trading program emission allowances to satisfy the emission allowance retirement obligations of CSAPR. In addition, while CAIR provided for unlimited trading, CSAPR establishes a more restricted emission trading program. For example, in any given year, if a utility's emissions cannot be covered by that utility's allowance allocation plus an approved variability limit, and the state's emissions exceeds the assurance level established by EPA, the utility would be required to retire a portion of those allowances at a higher than 1:1 ratio. This method in effect is intended to prevent any significant transfer of allowances across state boundaries and across years.

- Transport Rule II & III

  New Ozone NAAQS and the new PM2.5 NAAQS could require further SO_2 and NO_x reductions across the transport region. These two regulatory initiatives are expected to go beyond the requirements of the CSAPR and Utility Hazardous Air Pollutant ("HAP") MACT. The first initiative will be required by the new Ozone NAAQS. This rulemaking would address the interstate transport requirements of the CAA as they relate to revised ozone standards expected to be published in 2013. The new ozone standards could trigger a requirement for states to address any emissions that significantly contribute to downwind attainment and maintenance problems associated with the revised standards. Specifically, states are required by the CAA to address emissions that "significantly contribute" to nonattainment of the revised ozone standard in other states, and to address emissions that interfere with other states' ability to maintain the revised ozone standard. The EPA will need to evaluate how much an upwind state's emissions of NO_x may contribute to downwind states' ability to attain and maintain the new ozone standard. The EPA would address these emissions in Transport Rule II sometime after 2013. The second initiative is the new PM2.5 Ambient Air Quality Standards. In a manner similar to the approach mentioned above on the ozone standard, the EPA would address emissions of SO_2 and NO_x, which chemically react in the atmosphere to form fine particulate, in Transport Rule III. The EPA is expected to propose Transport Rule III in the 2013 timeframe. Compliance with both Transport Rule II and Transport Rule III is estimated to be required by 2018.

- Clean Air Mercury Rule ("CAMR")/Utility HAP MACT

  To control Mercury ("Hg") from coal-fired EGUs, the EPA created the CAMR, which was a market-based cap and trade program designed to reduce Hg emissions nationally in two phases. However, on February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAMR. In response to this vacatur, the EPA proposed a MACT for all HAPs, including Hg for electric generators. To develop supporting data for the Utility MACT, the electric utility industry and the EPA have expended an estimated $100 million on an Information Collection Request ("ICR"), which was completed in October 2010. The proposed Utility MACT was signed by the EPA and made available on March 16, 2011. The final MACT is scheduled to be issued by November 16, 2011.

  The Utility MACT will apply to approximately 1,200 coal-fired units and 150 oil-fired units. The emission rate limits for these sources are derived from the 12 percent lowest-emitting units that were tested by the ICR. The MACT addresses all HAPs; however, surrogate standards have been proposed. Therefore, the MACT is expected to set limits for the following categories of emissions considered by the EPA to be HAPs for coal-fired and solid oil-derived fuel-fired EGUs:

    - Hg
    - Total PM (surrogate for non-Hg metals)
    - SO_2 or Hydrogen Chloride ("HCI") (surrogate for acid-gas HAPs)
    - Work practice standards for volatile organic and Dioxin/Furan

Table 8-1 illustrates the subcategories and emission limitations for coal-fired and solid oil-derived fuel-fired EGUs under the proposed Utility HAP MACT.

Table 8-1
Proposed Emission Limitations for Coal and Solid Oil-Derived Fuel-Fired EGUS

Subcategory	2012 SO_2 Allocation	2014 SO_2 Allocation	Mercury
Existing Coal-fired Unit Designed for Coal ≥ 8,300 Btu/lb	SO_2	0.0020 lb/mmbtu	1.0 lb/TBtu, EPA is expected to change to 1.2 lb/TBtu
Existing Coal-fired Unit Designed for Coal < 8,300 Btu/lb	0.030 lb/mmbtu	0.0020 lb/mmbtu	4.0 lb/TBtu
Existing – IGCC	0.050 lb/mmbtu	0.00050 lb/mmbtu	3.0 lb/TBtu
Existing Solid Oil-Derived	0.20 lb/mmbtu	0.0050 lb/mmbtu	0.20 lb/TBtu
New Coal-fired Unit Designed for Coal ≥ 8,300 Btu/lb	0.050 lb/MWh	0.30 lb/GWh	0.000010 lb/GWh
New Coal-fired Unit Designed for Coal < 8,300 Btu/lb	0.050 lb/MWh	0.30 lb/GWh	0.040 lb/GWh
New – IGCC	0.050 lb/MWh	0.30 lb/GWh	0.000010 lb/GWh
New Solid Oil-Derived	0.050 lb/MWh	0.00030 lb/MWh	0.0020 lb/GWh

- Regional Haze Issues
  The EPA is also required to address regional haze issues under the CAA. On October 3, 2007, the State of Indiana adopted a rule to implement the EPA Best Available Retrofit Technology ("BART") requirements for reduction of regional haze. The rule became effective February 22, 2008, and required BART controls within five years (2013). The language of the final rule relied upon the provisions of the Indiana CAIR to meet requirements for NO_x and SO_2 BART controls and would not have imposed any additional control requirements on coal-fired electric generation station emissions of these pollutants. As part of the BART analysis process, IDEM continues to evaluate the potential impact of PM from EGUs to determine if there are impacts on Class I areas. If a BART exemption is not available, for example as a result of the CAIR rule being vacated, and if EPA determines CSAPR reductions are not considered BART, then further NO_x and SO_2 reductions may be required from NIPSCO generating stations. The requirement for additional control would be contingent upon further regional haze impact analyses identifying contributing sources.

Consent Decree

On September 29, 2004, the EPA issued a Notice of Violation ("NOV") to NIPSCO for alleged violations of the CAA and the SIP. The NOV alleges that modifications were made to certain boiler units at three of NIPSCO's generating stations between the years 1985 and 1995 without obtaining appropriate air permits for the modifications. NIPSCO, the EPA, the Department of Justice, and the IDEM have agreed to settle the matter.

The Consent Decree was entered by the United States District Court for the Northern District of Indiana on July 22, 2011. The Consent Decree covers NIPSCO's four coal generating stations: Bailly, Michigan

City, Schahfer, and Mitchell. NIPSCO surrendered CAA permits for Mitchell's coal-fired boilers, which have not been used to generate power since 2002. At the other generating stations, NIPSCO must install additional control equipment, including three new SO_2 control devices and one new NO_x control device. The consent decree also imposes emissions limits for NO_x, SO_2, and PM, and annual tonnage limits for NO_x and SO_2. In order to continuously meet the emission limitations, NIPSCO plans to install duct burners for the SCRs. During certain conditions, such as startup or operation at low loads, the exhaust gas temperatures entering the SCR can be too low for the catalytic reaction to effectively take place. The purpose of the duct burners is to increase the temperature of the boiler exhaust gases entering the SCR system in order to achieve the desired SCR operating temperature during low load operation and boiler startups. The installation of the duct burners will allow commencement of operation of the SCR system sooner after startup, and, more importantly, maintain effective NO_x control during low load operations when flue gas temperature can drop, thereby minimizing the potential for unit shutdowns. In addition, NIPSCO must surrender specified NO_x and SO_2 allowances, pay fines of $3.5 million, and invest $9.5 million in environmental mitigation projects.

Clean Water Act ("CWA")

The CWA establishes water quality standards for surface waters as well as the basic structure for regulating discharges of pollutants into the waters of the United States. Under the CWA, EPA implemented pollution control programs such as setting wastewater standards for industry, including electric utilities. In addition, the CWA made it unlawful to discharge any pollutant from a point source into navigable waters without a permit. The National Pollutant Discharge Elimination System permit program implements the CWA's provisions and prohibits unauthorized discharges by requiring a permit for point sources impacting waters of the United States.

CWA 316(b) Cooling Water Intake Structures - Section 316(b) of the CWA requires all large existing steam electric generating stations with cooling water intake structures deploy the best technology available to minimize adverse environmental impacts to fish and shellfish. The EPA's rule implementing Section 316(b) became effective on September 7, 2004. Litigation ensued, and on January 25, 2007, the Second Circuit Court remanded the matter to the EPA to reconsider the options in the regulation that provided for flexibility in meeting the requirements of the rule. Shortly thereafter, the EPA suspended the 316(b) Phase II Rule which governs cooling water withdrawals. The EPA then instructed state and regional regulators implementing Section 316(b) that permits could be issued using best professional judgment to determine the best technology available for reducing adverse environmental impact. Various parties submitted petitions for a *writ of certiorari* to the U.S. Supreme Court in early November 2007 seeking to reverse the Second Circuit Court's decision. On April 14, 2008, the U.S. Supreme Court granted the petitions limiting the review to one question. On April 1, 2009, the Supreme Court issued their ruling reversing and remanding the Second Circuit's ruling. The case, *Entergy Corp. v. Riverkeeper, Inc.*, determined that the EPA did not overstep its authority when it adopted national performance standards utilizing cost-benefit analyses. The matter was remanded back to the Second Circuit U.S. Court of Appeals for further proceedings.

On April 20, 2011, the EPA proposed a rule for "existing" facilities and new units at existing facilities to codify this approach. The EPA is obligated to finalize the rule by July 27, 2012.

The proposed rule leaves much to the discretion of the permit writer (and the EPA Region that reviews the permit), particularly the entrainment mortality requirements for existing facilities. The rule sets separate standards for impingement mortality and entrainment mortality. The NIPSCO Michigan City and Schahfer Stations, which have closed cycle cooling systems, would be required to conduct further impingement and entrainment studies, install traveling screens, and fish return systems. Additional provisions may require a change to the cycles of concentration by which the plants operate to minimize water withdrawal. NIPSCO's Bailly under the proposed rule, which does not have closed cycle cooling, would require more studies including one that takes into consideration nine site specific criteria by which a determination would be made on the intake flow control technology. Likely, modifications to the plant would require an intake velocity reduction to less than 0.5 ft/sec. and similar changes to the traveling screens coupled with a fish return system.

Electric Steam Power Effluent Guidelines - The EPA in 2009 announced plans to revise the existing Steam Electric Effluent Guidelines affecting electric power plants and, in the process, is focusing on numerous power plant operations, including the effluent generated from coal ash handling systems, metal cleaning operations, wastewater treatment, surface impoundments, landfill operations, and FGD systems used to scrub SO_2 from air emissions. An EPA Information Collection Request to support the rulemaking was received by NIPSCO in mid-June 2010 and has since been completed. The ICR sought information from a wide range of steam electric power generating industry operations in order to characterize waste streams, understand the processes that generate the wastes, gather environmental data, and assess the availability and affordability of treatment technologies.

Currently, the data has been collected and is being reviewed by the EPA. The EPA intends to propose a rule within 2 years and issue a final rule 1-1/2 years thereafter. Once the new rule is finalized, the EPA and states would incorporate the new effluent standards into the generating station wastewater discharge permits.

Solid Waste Management

On June 21, 2010, the federal government proposed more stringent regulations concerning Coal Combustion Residuals ("CCR") as a result of the December 22, 2008 dike collapse at the Tennessee Valley Authority Kingston Generating Station. The EPA is currently investigating facility standards and operations relating to CCR management practices nationwide. A Notice of Data Availability ("NODA"), which is the result from information discovered in the comments, is expected to be issued sometime in the fall, 2011. A final determination is expected sometime in the 2012 timeframe.

In the 2000 Bevill Determination, the EPA determined that regulation of coal ash as hazardous waste under the Resource Conservation and Recovery Act ("RCRA") Subtitle C is not warranted. The EPA did, however, express the opinion that these materials, when deposited in landfills, surface impoundments or used as mine fill, should be regulated as RCRA Subtitle D wastes. While the EPA has not yet determined whether the management of CCR should be federally regulated or governed by state oversight, some form of regulation resembling RCRA Subtitle D standards are expected in the near future.

NIPSCO's current CCR management practices are closer to meeting the proposed standards for RCRA Subtitle D compliance than many utility counterparts. The permitted disposal facility at Schahfer has a composite liner and a leachate collection system. The facility has a network of groundwater monitoring wells, which are sampled twice per year. Substantial groundwater monitoring systems have also been recently installed at both Michigan City and Bailly. Michigan City has 13 wells and Bailly has 69 permanent wells.

NIPSCO utilizes dry fly ash handling systems for virtually all of its fly ash, with the exception of a small fraction at Michigan City. There is a relatively small amount that is periodically sluiced to a holding pond and periodically removed for disposal at Schahfer disposal facility. If the more stringent aspects of the proposed ruling are approved, coal-fired EGU operators will be required to upgrade CCR management practices.

NIPSCO Emission Allowance Inventory and Procurement Practices

Title IV Acid Rain - SO2 Emission Allowance Inventory

Under the CAIR SO_2 program, the Title IV (Acid Rain) SO_2 allowances are used on a discounted basis. During the first phase of the CAIR SO_2 program starting in 2010, the acid rain allowances are used at a 2 to 1 ratio (25,353 is half of 50,706 or 50% value). The CSAPR will replace CAIR in 2012 although the Title IV Acid Rain program will continue. Table 8-2 below, lists by year, the actual number of SO_2 allowances held in inventory by NIPSCO as of September 2011 for the period 2011 through 2032.

Table 8-2
Acid Rain Program
SO2 Allowance Inventory*

Year	Allowances**
Bank***	127,281
2011	30,706
2012	45,706
2013	50,706
2014	213,393
2015	25,706
2016	36,606
2017	50,706
2018	50,706
2019	50,706
2020	50,706
2021	50,706
2022	50,706
2023	50,706
2024	50,706
2025	50,706
2026	50,706
2027	50,706
2028	50,706
2029	50,706
2030	50,706
2031	50,706
2032	50,706
2033	50,706
2034	50,706
2035	50,706
2036	50,706
2037	50,706
2038	50,706
2039	50,706
2040	50,706
Total	**1,747,048**

* *The table provides the allowance inventory available on June 27, 2011.*
** *The number of allowances in the inventory is not adjusted for CAIR retirement ratios.*
*** *Bank reflects emission allowances 2010 or earlier.*

CAIR Emission Allowance Inventory

As stated above, CAIR is expected to be in effect through 2011 with CSAPR replacing CAIR in 2012. Tables 8-3 and 8-4 lists NO_x annual and ozone season allowance inventory issued to NIPSCO.

Table 8-3
CAIR Annual NO_x Allowance Inventory*

Plant Name	Bank**	2011	2012	2013	2014	Grand Total
Bailly	838	2,599	2,599	2,599	2,599	**11,234**
Mitchell		1,760	1,760	1,760	1,760	**7,040**
Michigan City	2,738	2,222	2,222	2,222	2,222	**11,626**
Schahfer	70	14,469	9,069	9,069	9,069	**41,746**
Sugar Creek	196	158	158	158	158	**828**
Grand Total	**3,842**	**21,208**	**15,808**	**15,808**	**15,808**	**72,474**

** The table provides the allowance inventory available on June 27, 2011.*

*** Bank reflects emission allowances 2010 or earlier.*

Table 8-4
CAIR NO_x Ozone Season Allowance Inventory*

Plant Name	Bank **	2011	2012	2013	2014	Grand Total
Bailly	2,485	1,141	1,141	1,141	1,141	**7,049**
Mitchell	756	715	715	715	715	**3,616**
Michigan City	500	1,026	1,026	1,026	1,026	**4,604**
Schahfer	2,286	3,905	3,905	3,905	3,905	**17,906**
Sugar Creek	180	134	134	134	134	**716**
Grand Total	**6,207**	**6,921**	**6,921**	**6,921**	**6,921**	**33,891**

** The table provides the allowance inventory available on June 27, 2011.*

*** Bank reflects emission allowances 2010 or earlier.*

CSAPR Emission Allowance Inventory

The CSAPR is expected to become effective for 2012 and beyond. Tables 8-5 and 8-6 list the SO_2 and NO_x allocations expected to be issued to NIPSCO.

Table 8-5
Annual SO_2 Allocation per Generating Station

Plant Name	Boiler ID	SO_2 Emissions 2010 (tons)	SO_2 Allocation 2012 (tons)	SO_2 Allocation 2014 (tons)
Bailly	7	3,051	2,613	1,445
Bailly	8	6,139	4,486	2,481
Michigan City	12	9,730	6,249	3,456
Schahfer	14	11,952	6,700	3,706
Schahfer	15	9,753	7,903	4,371
Schahfer	16A	0	0	0
Schahfer	16B	0	0	0
Schahfer	17	2,522	6,289	3,478
Schahfer	18	2,838	6,439	3,562
Sugar Creek	CT11	2	2	2
Sugar Creek	CT12	2	2	2
Total		**45,988**	**40,683**	**22,503**

Table 8-6
Annual and Season NO_x Allocation per Generating Station

Plant Name	State	Boiler ID	NO_x Annual Emissions 2010 (Tons)	NO_x Annual Allocation 2012 (Tons)	NO_x Annual Allocation 2014 (Tons)	NO_x Ozone Season Emissions 2010 (Tons)	NO_x Ozone Season Allocation 2012 (Tons)	NO_x Ozone Season Allocation 2014 (Tons)
Bailly	Indiana	7	916	967	956	486	371	365
Bailly	Indiana	8	1,844	1,661	1,641	978	640	631
Michigan City	Indiana	12	1,161	2,313	2,286	587	1,100	1,084
Schahfer	Indiana	14	1,835	2,481	2,451	947	1,177	1,159
Schahfer	Indiana	15	3,094	2,926	2,891	1,248	1,165	1,148
Schahfer	Indiana	16A	15	7	7	12	6	5
Schahfer	Indiana	16B	14	10	10	11	9	9
Schahfer	Indiana	17	2,051	2,328	2,300	1,169	1,017	1,002
Schahfer	Indiana	18	2,603	2,384	2,355	1,075	1,020	1,004
Sugar Creek	Indiana	CT11	44	189	189	23	142	139
Sugar Creek	Indiana	CT12	46	101	101	24	92	92
Total			**13,623**	**15,367**	**15,187**	**6,559**	**6,739**	**6,638**

Process Used in Developing NIPSCO's Environmental Compliance Plan

NIPSCO Compliance Planning Process

Since the pace of regulatory change from EPA air rulemakings has been and will continue to be highly dynamic, NIPSCO uses a combination of external consulting resources and internal staff to develop and adjust environmental compliance plans. Consultants and architectural and engineering firms are utilized to assist NIPSCO in developing emission control cost estimates and perform modeling of NIPSCO environmental requirements to develop compliance plans to address proposed and expected EPA rules. As the rules change, the plans are adjusted to comply with the new requirements.

Multi-Pollutant Compliance Plan ("MPCP")

The MPCP takes a cost effective approach across multiple regulated air emission control requirements. In many cases, a lower cost control program is achieved when controls such as FGD are selected that provide for emission reductions of multiple pollutants. In addition, the MPCP ultimately does not rely on the long term purchase or sale of emission allowances in lieu of air pollution controls for compliance, but rather targets compliance through installation of controls on the NIPSCO units. There are several reasons for this approach; namely to achieve emission reductions that will lead to improvements in local and regional air quality, to gain local economic benefits from installation of emission controls and to avoid the inherent risks of relying on uncertain emissions markets for compliance. Although for compliance purposes, NIPSCO cannot rule out the possibility that the emission allowance markets could be used to purchase or trade emission allowances in order to fully comply with the environmental requirements. Market exposure is reduced through the installation of air emission controls.

NIPSCO MPCP Development Methodology – EPA Air Rulemakings

The MPCP analysis developed a cost-effective compliance plan for NIPSCO under recent and anticipated EPA air regulatory programs described above. To address the environmental requirements, the model was based on the proposed EPA CATR (now finalized as the CSAPR) and the proposed National Emission Standards for Hazardous Air Pollutants ("NESHAP") from Coal- and Oil-fired Electric Utility Steam Generating Units referred to as the Utility MACT rule. However, in order for the analysis to reflect the regulatory programs being pursued by the EPA during the next several years, two pending regulatory initiatives, Transport Rule II and Transport Rule III described above, were included in the modeling. These two other regulatory initiatives are expected to require further SO_2 and NO_x reductions to address the new Ozone and PM2.5 NAAQS.

To accomplish this evaluation, the *Emission-Economic Modeling System ("EEMS")* was utilized to evaluate control options between 2012 and 2025. *EEMS* is a model that determines a compliance solution for an individual utility under a specific regulatory regime using a set of prescribed decision rules.

EEMS

The EEMS is a computer model that was developed in 1997 by Jim Marchetti, Ed Cichanowicz and Mike Hein to perform specific emission and economic analyses of environmental policies and regulations impacting the electric utility and coal industries. EEMS uses a set of decision rules to identify a combination of control options (technology versus allowances) for a given utility system under a specific regulatory regime. In evaluating any multi-pollutant proposal, EEMS employs a step-wise approach to evaluate emission reduction requirements. The selection of the order (or driver) is based upon the effect compliance with a particular reduction requirement would have upon the emissions of other gases due to changes in fuel and technology. These feed-back mechanisms within EEMS allow the model to re-adjust emission levels based upon compliance decisions(s) related to the emissions of a particular species (e.g., Hg co-benefits from FGD and SCR installations).

Unlike some utility models that model reference plants, compliance options are evaluated at the unit and system levels, which allows for greater flexibility in addressing multiple compliance options for a specific unit based upon its individual characteristics. This provides a more accurate picture of compliance choices and compliance costs

The EEMS Data Base, which is the primary input file for EEMS, contains detail on the electric utility sector, including unit design, fuel, unit operation and production costs, current and future air pollution control equipment, current disposal methods and costs, emission control assumptions and costs, and unit specific emission rates for over 2,500 steam electric units and all operating CT and combine-cycle units. In addition to current information, the Data Base contains historical unit operational data for steam electric (e.g., fuel consumption and quality, generation,) that extends back to 1980. The Data Base is updated as new unit specific information becomes available.

Evaluation Assumptions for EEMS

This section outlines the regulatory and technical assumptions that were utilized in the development of the MPCP.

Base Environmental Regulatory Compliance Assumptions

Three regulatory regimes were developed for modeling: the (i) CATR/CSAPR; (ii) Utility MACT; and, (iii) TR II and TR III. These three initiatives or EPA Air Rulemakings are detailed below:

- CATR/CSAPR - The CATR follows the targets and timetables outlined in the EPA proposed rule of July 6, 2010, which requires EGUs in 32 eastern states to reduce SO_2 and NO_x emissions beginning in 2012. The first phase of these emission reductions in all 32 states would begin in 2012 and in 2014 there would be further SO_2 emission reductions in 15 states. EPA's SO_2 unit allocations for 2012 and 2014 and for NO_x the annual and seasonal allocations based upon the NODA III - Option 1 allocation method were used. The EPA's preferred approach allows for intra-state trading of allowances, with limited inter-state trading of allowances. Note: CSAPR was not originally modeled. However, as described below, based on the recent CSAPR allocations the Unit 15 FGD may be needed earlier to meet the SO_2 allocation.

- MACT – The MACT regime includes compliance with the above mentioned CATR and compliance with the proposed Utility MACT by 2016. The HAPs that were modeled are as follows:
    - Hg – an emissions limit of 1.0 lb Hg/TBtu.
    - PM – a surrogate for non-mercury metals requiring an emission rate of 0.030 lbs/mmbtu of total particulate for both condensable and filterable PM. For this study, 0.020 lbs/mmbtu of filterable particulate is used as an estimate of the filterable component of total particulate.

- HCl – SO_2 is used as a surrogate for HCl with a limit of 0.20 lb/mmbtu.[3]
- Work practice standards are proposed to insure all burner equipment is operable, promoting good combustion and thereby minimizing any organic HAP emissions proposed for regulation.[4]

- TR II and TR III – The TR II (NO_x) and TR III (NO_x and SO_2) regimes assume that NIPSCO would have to achieve a system-wide emission rate of about 0.11 lbs/mmbtu for both SO_2 and for annual NO_x by 2018; however, intra-state trading of allowances would be allowed. There should be no carry-over of banked CATR allowances for compliance. Both TR II and TR III are considered in addition to or beyond the CATR/MACT regime.

The SO_2 NAAQS was not specifically evaluated in this analysis. However, Indiana will soon need to review air quality levels across the state and make recommendations to the EPA on whether the state meets the new standards. During this process Indiana will review areas with electric generating stations to determine if additional emission control measures may be needed to comply with the new NAAQS. IDEM has stated its intent to model SO_2 air quality impacts from coal-fired EGUs in Indiana. Based upon the monitored SO_2 concentrations across Indiana, further SO_2 reductions from coal fired EGUs will likely be necessary to achieve compliance with the new one hour SO_2 NAAQS. Since there are no current estimates of emission levels that may be required from IDEM for achieving the SO_2 NAAQS, the SO_2 NAAQS could not be evaluated in this study. However, compliance with the SO_2 NAAQS implementation plan is not expected to be required until either 2017 or 2018, which should coincide with NIPSCO having all coal fired units scrubbed.

Base Technical Compliance Planning Assumptions

Future Unit Generation Levels - Annual fossil unit generation levels and annual heat input for the years 2010 through 2025 for all generating units, including Sugar Creek were utilized as the model input. Future generation levels through 2025 for Indiana's other fossil generating units were estimated by EEMS using regional coal, oil and gas generation growth rates developed from EIA's Annual Energy Outlook 2010 (AEO2010) Reference Case (April 2009). These future generation levels were used in computing SO_2 and NO_x allowance prices for the CATR and TR II and TR III regulatory scenarios.

Unit Emission Rate Data **-** The baseline emission rates for SO_2, NO_x, PM and Hg, for all the Company's fossil units, were based upon recent emission levels. HCl emission rates were calculated based upon the coal heat content and chlorine content, and translated into lbs/mmbtu.

Fuel Usage Assumptions **-** For the purpose of the study, NIPSCO assumed that the current coal supply plan would be maintained into the future. The analysis did not specifically evaluate switching of coals as a result of a technology deployment. However, wet flue gas desulfurization ("WFGD") could potentially allow for coal fuel flexibility under the regulatory scenarios analyzed.

[3] See page 851 of the proposed National Emission Standards for Hazardous Air Pollutants (NESHAP) from Coal- and Oil-fired Electric Utility Steam Generating Units (March 16, 2011).

[4] Instead of operating limits for dioxins and furans and non-dioxin/furan organic HAP, the EPA is proposing that owners or operators of units submit documentation that a "tune up" meeting the requirements of the proposed rule was conducted.

Technology Control Costs and Performance **-** Specific technology cost and performance assumptions were either provided by NIPSCO or by Sargent & Lundy from preliminary WFGD cost estimates for Schahfer Unit 14 and Unit 15.[5] These specific technology assumptions were incorporated into *EEMS.* The cost and performance assumptions for other compliance options in which site specific engineering was not available were either derived from the technology file of *EEMS*, which is based upon industry experience, or developed for this analysis. Briefly the control options that were modeled are as follows:

SO_2 Controls

- WFGD defined as conventional limestone based process, employing forced oxidation to produce gypsum.
- Dry FGD ("DFGD"), employing a lime-based spray drying process, and including a fabric filter for both fly ash and sulfate particulate control.
- FGD Upgrade, employing minor modifications to the spray tower to improve flue gas mixing with injected reagent, and changing to spray nozzles to enhance the distribution of reagent. The use of additives such as dibasic acid ("DBA") or formic acid to control FGD liquor pH is also options to improve SO_2 control.

NO_x Controls

- SCR, based on conventional anhydrous-based systems.
- Selective Non-Catalytic Reduction ('SNCR"), employing urea as a reagent.

Hg Controls

- Halogenated Activated Carbon Injection ("HACI"), employing halogenated (e.g. bromine) enhanced activated carbon, injected into an existing ESP.
- Fabric Filter ("FF") with ACI or HACI, requiring the retrofit of both a fabric filter and an ACI system.
- Catalyst Management Enhancements ('CME'), employing accelerated change out of catalyst – typically at annual outages – to increase the oxidation of Hg to $Hg(Cl)_2$.
- HACI ESP using additional ESP plate area ("ESP-HACI")

PM Controls

- Upgrade/Rebuild ESP with Existing Envelope employing improved flue gas distribution across the ESP plates and enhanced or optimized energization of electrodes (ESP Upgrade) and/or,
- Add Extra Single Collecting Field comprised of increasing the specific collecting area ("SCA") by adding an extra collecting field, or increasing the plate height. This step is most effective when implemented in conjunction with a rebuild of the existing ESP, as described in the previous passage; the cost to implement this option includes both (ESP Upgrade).
- Baghouses ("BH"), requiring complete retrofit of a fabric filter baghouse.

HCl Controls

- FGD removal, whereby a process designed for SO_2 removal will provide significant HCl removal. There is little HCl removal data on commercial equipment to support this assumption, but the relatively high solubility and low flue gas concentration of HCl (compared to SO_2) suggests removal will supersede levels for SO_2.

[5] Sargent & Lundy, R.M. Schahfer Generating Station Unit 14 FGD Retrofit Project, January 27, 2011.

Work Practice Standards

- Boiler Tuning, in which consistent (e.g. at 18 month intervals) inspection and adjustment of burner registers and associated equipment to assure a uniform distribution of fuel and air.

Proposed CATR Allowance Allocations **-** The *CATR* SO_2 and NO_x unit allocations that were used in the analysis were based upon the unit specific allocations listed in the *CATR* NODA III and determined by the Option 1 allocation procedure (January 2011).[6] Table 8-7, illustrates the SO_2 and NO_x allocations that were incorporated into the modeling.

Table 8-7
CATR SO_2 and NO_x Allowances

Plant Name	Boiler ID	2012 SO_2 Allocation	2014 SO_2 Allocation	2012 NO_x Annual Allocation	2012 NO_x Seasonal Allocation
Bailly	7	3,289	1,655	950	386
Bailly	8	6,163	3,100	1,781	716
Bailly	10	3	1	1	1
Michigan City	12	8,617	4,335	2,490	1,214
Schahfer	14	8.907	4,480	2,574	1,204
Schahfer	15	9,879	4,970	2,855	1,188
Schahfer	16	73	36	21	19
Schahfer	17	8,793	4,423	2,541	1,106
Schahfer	18	8,734	4,394	2,524	1,094
Sugar Creek		1,100	553	318	219
Total		**55,558**	**27,949**	**16,053**	**7,148**

Also, no banked Title IV/CAIR SO_2 and CAIR NO_x allowances were carried forward beginning in 2012 to comply with *CATR*.

Impact of Final CSAPR

CSAPR resulted in lower SO_2 and NO_x allocations for Indiana as compared to the proposed CATR allocations. The CSAPR budget for SO_2 in Phase I is about thirty percent (30%) less than the budget proposed in the CATR and the budget for SO_2 in Phase II is about twenty percent (20%) less than the budget proposed in the CATR. The NO_x budgets are only slightly lower, about five percent (5%). The net result is that the 2012 Indiana SO_2 and NO_x allocation budgets are approximately thirty-three percent (33%) and six percent (6%), respectively, below the 2010 actual emission levels. For 2014, the reductions are approximately sixty-two percent (62%) for SO_2 and seven percent (7%) for NO_x below 2010 actual emission levels. In 2012, NIPSCO's CSAPR SO_2 emissions allocations are approximately

[6] The NODA III – Option 1 allocation method utilizes 2005 to 2009 heat input from EPA CEMs data and then calculates the average of the three highest non-zero values within the five year period for each unit, which determines a pro-rata share of the state budget.

twelve percent (12%) below NIPSCO's 2010 emissions levels. In 2014, NIPSCO's CSAPR SO_2 emissions allocations are approximately fifty-one percent (51%) below NIPSCO's 2010 levels.

For the CSAPR program, the 2012 through 2014 timeframe is a period during which the utility industry will be challenged to reduce emissions to meet the tighter CSAPR emission budgets with only a limited amount of time available to install additional pollution controls to lower emissions. The CSAPR trading program design provides a strong incentive for utilities to physically reduce emissions to be within the utility's emissions budget plus the EPA's allowable annual variance. Any utility system emissions above that level for a utility located in the state that also exceeds the state budget plus the annual EPA variance will be subject to an additional emission allowance surrender requirement of two allowances for each ton of emissions above that level. NIPSCO believes that the lower emissions budget and aggressive implementation schedule of CSAPR when considered in combination with the trading program rules will put a utility at significant compliance risk, if it were to attempt to completely rely on the emission allowance market for compliance. Emission allowances may not be available in adequate quantities because utilities will either not be able to physically emit less SO_2 than their emission allowance allocation or, if they do emit less, will most likely bank those emission allowances to meet the emission budget reduction in 2014 rather than sell excess emission allowances. However, in spite of above, NIPSCO cannot rule out the possibility that there could be a need to go to the market to attempt to purchase or trade a certain amount of SO_2 emission allowances in order to fully comply with the requirements of CSAPR.

While NIPSCO's existing FGDs and low sulfur fuels should provide compliance with the CSAPR Phase I emission allocation, NIPSCO will need both the Schahfer Unit 14 and Unit 15 FGDs to comply with the much lower CSAPR Phase II 2014 SO_2 allocations. Therefore, in order for NIPSCO to comply with the emission allowance allocations under CSAPR, the Schahfer Unit 14 FGD will need to begin operation on the current schedule. NIPSCO will also need to bank SO_2 emission allowances in 2012 and 2013 and accelerate the Unit 15 FGD schedule (relative to the schedule in Table 8-8) to ultimately achieve reductions necessary to meet the allocations associated with Phase II of CSAPR. No further NO_x reductions are likely needed beyond the current control strategy for NIPSCO to meet the NO_x 2012 or 2014 allocations.

Utility MACT Status – Proposed Rule

NIPSCO has developed preliminary plans addressing the proposed Utility MACT rule and is further evaluating those plans with a more detailed study. Since NIPSCO will have or will install FGD on each of the coal-fired units, use of FGD with the co-benefits of HAP removal will be utilized as the primary mechanism by which NIPSCO will comply with the Utility MACT. NIPSCO believes that the most likely outcome of the final Utility MACT rule would necessitate installation of the Michigan City Unit 12 FGD sooner than the 2018 Consent Decree requirement such that engineering would need to begin as early as the first quarter of 2012 to meet an in-service date consistent with the timeline established in the proposed Utility MACT rule (i.e. either late 2014 or late 2015). The next challenge in meeting the proposed Utility MACT limitations will be in determining the appropriate strategy to meet the particulate and Hg emission limits. For particulate control, NIPSCO will evaluate existing electrostatic precipitators ("ESP") for upgrades as an alternative to installation of baghouse controls. For Hg, coal additives and/or activated carbon injection may be necessary to comply with the Hg limitation. NIPSCO will need to review the final Utility MACT rule to make an assessment of what, if any, additional controls may be needed for compliance, especially for Hg and particulate control.

Results of the Multi-Pollutant Analysis

The results of the EEMS modeling were compiled with the Consent Decree requirements and CSAPR (final form of the Transport Rule) to derive the updated MPCP. The results are presented in Table 8-8.

Table 8-8
Current System Compliance Plan including
Consent Decree, EPA Final CSAPR and Proposed MACT Rulemaking

Plant Name	Boiler ID	SO_2	NOx	Hg	PM
Bailly	7	FGD Upgrade 2014	SCR Duct Burners 2012	Additional Control Measures Needed as a Result of the Final Utility MACT Rule	
Bailly	8	FGD Upgrade 2014	SCR Duct Burners 2011		
Michigan City	12	DFGD 2016	SCR Duct Burners 2013		
Schahfer	14	WFGD 2014	SCR Duct Burners 2012		
Schahfer	15	WFGD 2016	SNCR 2012		
Schahfer	17		SNCR 2018		
Schahfer	18		SNCR 2018		

NIPSCO Sustainability Approach

NIPSCO is actively involved in sustainability efforts both in how we do business as well as in the communities we serve. The focus is on finding shared value opportunities with our stakeholders through enhancing the economic, social and environmental way we do business. The four cornerstones of sustainability efforts are to:

- Implement Customer-Focused Energy Solutions
- Promote Strong, Stable Communities
- Steward the Environment
- Assure an Engaged, Aligned and Transparent Approach

Details of NIPSCO's sustainability efforts can be found in the NiSource 2010 Sustainability Report.

2011

SECTION 9: RESOURCE ALTERNATIVES ANALYSIS

NIPSCO

INTEGRATED RESOURCE PLAN

Highlights – Resource Alternatives Analysis

- ***Supply-side options and demand-side resources analyzed to formulate optimal plan.***
- ***Plan tested at high and low demand, high and low commodity market prices, and construction cost escalation.***
- ***Sensitivities reflect all reasonably foreseeable outcomes.***
- ***Plan is robust not markedly affected by sensitivity tests.***

NIPSCO evaluates its resource options based on the forecast of customers' needs and the capabilities of its existing resources. In this section, NIPSCO integrates existing resources, supply side options and the direct load control ("DLC") program to evaluate, inform and determine the appropriate long-term plan. The Short-Term Action Plan is derived following NIPSCO's systematic integration of resource alternatives.

The NIPSCO Integration Analysis

NIPSCO's integration analysis assimilates the 2011 demand forecast with existing owned-generation, Demand-Side and Self-Build Supply-Side alternatives. A slate of ranked options is derived that ensures service is provided at the lowest reasonable cost to customers while at the same time satisfying NIPSCO's requirement for the most efficient, economical, flexible and reliable resource options.

The Demand-Side and Supply-Side integration began with eight options considered for meeting NIPSCO's future requirements. NIPSCO conducted the evaluation of the alternatives through Ventyx's Strategist® planning model. The composition of the options considered was as follows:

- 7 Self-Build Options; and
- 1 Renewable Self-Build Option

NIPSCO relied upon the Strategist® module PROVIEW™ to systematically explore and evaluate the various combinations of available Demand-Side and Supply-Side options to meet NIPSCO's short- and long-term future resource requirements. The plans were subjected to sensitivity and scenario analyses to test the robustness of each proffered resource combination. The integration process results in a ranking of various portfolios, or combination of resource portfolios, based on various constraints and optimizations. The resulting Short-Term Action Plan reflects NIPSCO's full evaluation of all alternative resource strategies.

Data from the Supply-Side and Demand-Side options was input directly into PROVIEW™ to evaluate each of the alternatives head-to-head. The total set of resource alternatives considered for the Demand-Side and Supply-Side integration consists of the short-list candidates from the Self-Build assessment. The alternatives were evaluated with particular attention provided to the resource start date. Not all alternatives were on equal footing with regard to the availability of the resource to meet NIPSCO's demonstrated resource requirements within the decision-making timeframe. The complete list of Self-Build options evaluated is shown in Table 9-1.

Table 9-1
Summary of Supply-Side Options

Option	Category	Year First Available
PC	Base	2021
IGCC	Base	2018
Nuclear	Base	2021
Brownfield CCGT	Intermediate	2016
Brownfield Conversion CCGT	Intermediate	2016
Brownfield CT_7FA	Peaking	2014
Brownfield CT_Aero	Peaking	2013
Wind	Renewable	2014

The complexity of the resource planning analysis is not apparent at this stage and should be described for a full understanding. Each alternative is a variable. In addition, its introduction into the resource mix is a variable. The impact of each alternative multiplies geometrically for each variable for each year the analysis progresses in time. Many other variables exist that impact each alternative. Each alternative is then compared against every other alternative. For illustrative purposes, consider the following, which is based on the methodologies used by NIPSCO in its resource review. Commonly, each resource decision has 2^x, where the 2 defines the choices, "build" or "do not build", and x represents the number of alternatives. For example, a planning decision with 5 alternatives will generate 2^5 or 32 branches. By year 2, the decision tree has another geometric progression of 32 branches, 32 times 32 or 1,024 branches. The resource decision cannot be evaluated with regard to only decisions made in Year 1. Because the number of resource plans or "branches" grows exponentially, it is important to establish "state space" that contains the most economical of the feasible plans. It is estimated that one nonillion (10^{30}) options would result if the options analysis were permitted to run unencumbered, attempting to justify and analyze all alternatives. Such a number is simply unworkable and inconceivable. In other words, every option is not and cannot be reviewed on a blank slate. The important step is to narrow the field, prudently and appropriately, by continually screening the alternatives and setting the optimization constraints in order to focus on the key decisions that are calculated to produce the best, cost effective, least cost integrated resource mix that meets all of NIPSCO's objectives.

Integration Analysis Assumptions

As described above, many variables impact the alternatives and the integration analysis. In order to rationalize both the alternatives and the integration analysis; key assumptions were made about NIPSCO, the MISO market, the demand forecast, and cost inputs. Rationalizing certain assumptions enabled NIPSCO to apply those assumptions consistently to all of the alternatives that were being evaluated.

The alternatives analysis consistently employed a number of key assumptions within the evaluation process. These key assumptions are:

- Economic
  Economic assumptions regarding the inflation rate were provided by IHS Global Insight. NIPSCO's capital structure, long-term debt rate, and allowed rate of return on equity were used to define the after-tax weighted cost of capital, discount rate.
- Planning Reserves
  The planning reserves were targeted at 3.81 percent throughout the IRP period, based on the MISO capacity planning protocol that tracks the reliability of generators by shifting the obligation of system wide reserves to the individual generators. Each generator's Installed Capacity is derated to the Unforced Capacity ("UCAP"). Based upon NIPSCO's generation fleet reliability, MISO's targeted UCAP planning reserve margin of 3.81 percent is roughly equivalent to using a planning reserve margin of 9 percent to 12 percent based on Installed Capacity. The projected forced outage metrics for each of NIPSCO's existing assets were provided by Operations and are consistent with NIPSCO's O&M plans. The projected forced outage metrics for the Self-Build Supply-Side resources were provided by MISO in their assessment of forced outage metrics for generic units.
- Demand and Energy Forecast
  The alternatives analysis adopted the Demand and Energy Forecast, see Section 4.
- Fuel Commodity and Transportation
  The alternatives analysis utilized the fuel commodity forecast for coal and natural gas. For NIPSCO's on-system natural gas pricing, the current commodity cost of natural gas price was assumed at Henry Hub and adjusted for the basis to the Chicago City Gate, plus transportation costs. For NIPSCO's Sugar Creek facility, the current commodity cost of natural gas was assumed at Henry Hub and adjusted for basis to the appropriate off-take point, plus transportation costs. In order to obtain transportation rates for each alternative, the location and the pipeline tariff rates, along with storage and balancing rates, were escalated for transportation over time.

  For coal pricing, coal site specific costs were assumed at the mine mouth, and incorporated transportation costs to account for benefits or detriments associated with location, i.e., rail or barge. The fuel assumptions are provided in CONFIDENTIAL Appendix F, Figure F-1.
- Environmental
  The environmental assumptions for NO_x, SO_2 and CO_2 were provided by PIRA. For further information on the environmental forecast see CONFIDENTIAL Appendix F, Figure F-2.
- External Energy Markets
  The external energy market forecast, from NIPSCO's trading organization, is based on a fully integrated and modeled scenario, taking into account reasoned market trends and public policy decisions regarding climate change and power generation fuel choice. This case represents NIPSCO's official forecast available to all internal stakeholders. NIPSCO's forecast is zonal in nature and the forecast represents the day-ahead energy prices for the Cinergy Hub adjusted by basis to the NIPSCO load hub. For further information on the external energy market forecast see CONFIDENTIAL Appendix F, Figure F-3.

  For the external market capacity price, NIPSCO used a combination of current futures market prices to reflect near term prices and a long-term forecast of capacity prices at the Cinergy Hub. The NIPSCO's current forecast of capacity prices indicates that capacity is not needed on the MISO market until 2016.

- Operating and Capital Costs
  The alternatives analysis incorporates the appropriate inputs regarding operating and capital costs associated with each facility type. The operating constraints for Wind and Solar renewable alternatives considered a typical day operations shape that defined the hourly output of the resource. NIPSCO relied upon historical wind and sun-shine data to derive a typical day shape. That typical day shape was used for all future years in the planning horizon.
- Off-System Sales
  The off-system market is modeled in accordance with MISO's operational model. All generation is sold into the MISO market at the generator hub and all load requirements are purchased from the MISO market at the NIPSCO load hub.
- Regulations
  The alternatives analysis incorporated a balanced set of existing and proposed regulations, laws, practices and policies.

Plan Development

Simulation Computer Model and Techniques

The operational analyses to integrate the Supply-Side and Demand-Side resources and formulate NIPSCO's long term used a single and fundamental method of analysis – Simulation. Unlike the more theoretical process employed through economic derivation, simulation is an analysis that is conducted from the "ground up." By contrast, technical analysis is formulaic derivation – one accepts an input variable and then derives an output variable. The simulation method of analysis most closely simulates NIPSCO's actual operating environment and is responsive to changes in conditions and variables.

The model simulates the real-world operation of a utility generation, distribution, and transmission system within an integrated market. The simulation is intended, in each round of alternatives analysis, to determine the cost and reliability effects of adding Supply-Side resources to the system or of modifying the load through DSM programs. The dynamic programming methodology limits the total number of options that can be examined at one time within a single analysis, while at the same time allowing for detailed and comprehensive analysis of operational and economic impacts from specific resource options. Careful structuring of the study constraints in conjunction with iterative analysis runs is required. See Appendix D for a description of Strategist® and PROVIEW™ models.

The basis for determining the ranking of the NPVRR of a mix of resources is established in Strategist® using its expansion planning module, PROVIEW™. In these simulations, the model examines the impact on the utility. As a first step, a reference case was developed with only Self-Build Supply-Side options through PROVIEW™ based upon the 2011 IRP Demand and Energy Forecast. The primary assumptions that served as the basis of this analysis appear in Table 9-2.

Table 9-2
Underlying Assumptions

Forecast Item	Percent Compound Annual Growth Rate
60-Minute MW Peak Demand Excluding DSM Effects	
5 year, 2012-2017	-0.19
10 year, 2012-2022	0.30
20 year, 2012-2032	0.66
Total MWH Energy Excluding DSM Effects	
5 year, 2012-2017	0.06
10 year, 2012-2022	0.10
20 year, 2012-2032	0.49
Natural Gas Prices for New Units Over 2012-2032	6.29
PRB Coal for New Units Over 2012-2032	2.54
Illinois Basin Coal for New Units Over 2012-2032	2.54
General Inflation Rate Measured by the CPI Over 2010-2030	1.88
Miscellaneous	**Value**
Weighted Cost of Capital (percent)	7.55
Planning Period (PROVIEW)	2012-2032
End Effects Period (PROVIEW)	0
Assumed Availability of Existing Coal-fired Units (years)	60
Assumed Availability of Existing Gas-fired Units (years)	40
Assumed Existing Units Unavailable (calendar year)	
Unit 9A	2014
Unit 10 (Retained for Black Start Capability)	2020
Unit 7	2023
Unit 8	2029

Using the dynamic programming logic of PROVIEW™, NIPSCO evaluates combinations of available Supply-Side and Demand-Side resource alternatives, called "states," in each year of the 20-year planning period. Each year's feasible states, those states passing all of Strategist's® study constraints, are used as the basis for generating new combination of options in the next year of alternatives. When the final year of the planning period has been analyzed, the states are "back-traced" to determine the timing of the resource additions. The back-traced analyses become the plans that PROVIEW™ will rank according to the NPVRR. The revenue requirement in this usage includes both the operational costs such as fuel and O&M, incremental capital costs associated with new construction, and capital costs associated with the existing system. All feasible plans that pass Strategist's® constraints are ranked in descending order of NPVRR.

NIPSCO Simulation Runs for Alternatives Analysis

Self-Build Supply Plan - Modeling runs were made with the intent of identifying common plan elements that could be fixed in order to drive efficiencies in the time of analysis, without a reduction in analytical flexibility, and to reduce unnecessary complexities in the alternatives analysis. This analysis was to determine a Self-Build Supply Plan by limiting the use of superfluous units. Superfluous units are combination of resource alternatives that allow additional units to be considered above NIPSCO targeted reserves levels and support off-system sales.

The number of Self-Build Supply plans, without considering superfluous units, was 315 unique plans. The occurrences for the Self-Build Supply options are enumerated in Table 9-3

Table 9-3
Distribution of Self-Build Supply-Side Options

Supply-Side Option	First Occurrence in Plan Series	# of Occurrences	% of Population	Earliest Year Selected
CCGT	1	91	28.89%	2023
CT_7FA	2	279	88.57%	2023
CT_Aero	3	254	80.63%	2023
Pulverized Coal	9	82	26.03%	2023
Conversion CCGT	23	92	29.21%	2027
IGCC	13	93	29.52%	2023
Nuclear	14	69	21.90%	2024

The most preferred resources are the CCGT, CT_7FA, and CT_Aero.

The Nuclear, PC and IGCC options were rarely selected. The top plan calls for a CCGT to be built in 2023. Focusing on the near term planning horizon, 2012 to 2024; there are six significantly different plans. The plan results are presented in Table 9-4.

Table 9-4
Top Significantly Different Plans

Plan	1	18	23	108	137	283
2012						
2013	Market	Market	Market	Market	Market	Market
2014	Market	Market	Market	Market	Market	Market
2015	Market	Market	Market	Market	Market	Market
2016	Market	Market	Market	Market	Market	Market
2017	Market	Market	Market	Market	Market	Market
2018	Market	Market	Market	Market	Market	Market
2019						
2020						
2021	Market	Market	Market	Market	Market	Market
2022	Market	Market	Market	Market	Market	Market
2023	**CCGT**	CT_Aero(2) CT_7FA Market	CT_7FA (2)	Pulverized Coal	Nuclear	IGCC
2024		**CCGT**				
2025						
2026			Market			
2027			Conversion			
2028						
2029	**CCGT**		**CCGT**	CT_7FA Market		Nuclear
2030		Market		CT_Aero Market		
2031		**CCGT**		CT_Aero (2) Market		
2032				**CCGT**		
NPVRR (2011 $000)	**12,932,337**	**13,115,935**	**13,120,875**	**13,666,929**	**15,178,669**	**15,348,670**

Sensitivities and Scenarios Analysis

To evaluate the risk associated with market uncertainty, NIPSCO's 2011 IRP developed a base case with various deterministic sensitivity analyses. The purpose of establishing a base case analysis is to reflect NIPSCO's current view of the future market, taking into account all reasonably foreseeable outcomes. It should be noted that the impact of a future Federal mandate to reduce carbon is included in the base case. The sensitivity analyses are performed in order to see how the various resource options will rank when different assumptions in key variables are assumed.

Another analytical process, available to NIPSCO, for sensitivity analyses is stochastic or Monte Carlo analysis. Monte Carlo algorithms are based on random sampling of input variable to simulate their impact on operational results. Monte Carlo is generally applied when it is infeasible to compute an exact result using deterministic methods. The major issue with Monte Carlo analysis of utility operations is the problem that erroneous data input will result in erroneous data output. Monte Carlo requires probability distributions over the range of possible inputs. The major requirement of Monte Carlo analysis is a large number of input iterations; the approximation improves with more data. Another key issue with Monte Carlo analysis is the interaction of variables or intra-variable correlations. Monte Carlo requires sound probability distributions and intra-variable correlation to produce thousands of possible outcomes. The results are then statistically analyzed to determine the probabilities of different outcomes. By contrast, NIPSCO has elected to use a deterministic approach using single point estimates; expected, best, and worst for input variables, including intra-variable correlation. NIPSCO believes that a deterministic approach is the most cost-effective approach to quantifying risk.

Description of Base Case - The Base Case for the 2011 IRP was based on a “best reasonable projection” or expected case view of future economic, demographic and energy use conditions. These assumed conditions are best described as representing a “P50”, 50th percentile or average, view of the future. In addition, a carbon cap and trade program is assumed to begin in 2020.

High and Low Case Sensitivity Analyses - The high and low sensitivity data was developed on load growth and general market conditions (coal, natural gas, and electric market). The high sensitivity data was developed on price escalation resulting from inflation, carbon cap and trade prices, and short-term capacity market conditions. Analysis for demand and energy was based on a load forecast provided by NIPSCO’s Forecasting Group. The load growth sensitivities are presented in CONFIDENTIAL Appendix F, Figure F-4.

Tested Sensitivity - High Construction Escalation - High construction escalation sensitivity assumed a capital escalation rate of five percent. A low case was not conducted because low price escalation is not of concern.

Tested Sensitivity – High and Low Market Conditions - The high and low market conditions forecasts were provided by Ventyx. The charts related to these sensitivities are found in CONFIDENTIAL Appendix F, Figures F-5 and F-6.

The top six significantly different plans were subjected to the sensitivities. The results are in Table 9-5.

Table 9-5
Tested Sensitivity Results

	Plan 1	Delta	Plan 18	Delta	Plan 23	Delta
High Load Growth	$14,994,901	16%	$15,182,614	16%	$15,247,533	16%
Base	$12,932,337		$13,115,935		$13,120,875	
Low Load Growth	$11,131,037	14%	$11,313,387	14%	$11,318,068	14%
High Construction Escalation	$13,059,622	1%	$13,258,769	1%	$13,261,094	1%
Base	$12,932,337		$13,115,935		$13,120,875	
High Market	$14,084,813	9%	$14,317,302	9%	$14,352,233	9%
Base	$12,932,337		$13,115,935		$13,120,875	
Low Market	$11,712,274	9%	$11,850,002	10%	$11,817,832	10%

	Plan 108	Delta	Plan 137	Delta	Plan 283	Delta
High Load Growth	$15,769,710	15%	$16,004,301	5%	$17,428,463	14%
Base	$13,666,929		$15,178,669		$15,348,670	
Low Load Growth	$11,864,147	13%	$13,377,410	12%	$13,547,393	12%
High Construction Escalation	$13,944,756	2%	$15,504,667	2%	$16,284,003	6%
Base	$13,666,929		$15,178,669		$15,348,670	
High Market	$14,399,385	5%	$17,239,171	14%	$15,754,290	3%
Base	$13,666,929		$15,178,669		$15,348,670	
Low Market	$12,727,604	7%	$14,677,675	3%	$14,715,537	4%

The bounds around the sensitivities indicate that NIPSCO's risk exposure is consistent across the plans. Plans 108, 137 and 238 provide value in the high load growth case. However, the "hedge" against higher growth is not cost effective given the cost differential to the number one plan. Plans 108, 137 and 283 are negatively impacted by high construction escalation due to construction lead time and high capital requirements. Plans 108 and 283 provide value with regard to the high and low market sensitivities. However, the "hedge" against external market prices is not cost effective given the cost differential to the number on plan. Plan 137 increases NIPSCO's risk to high market sensitivity.

Scenario Analyses

To evaluate the risk associated with regulatory market uncertainty, NIPSCO's 2011 IRP developed a base case with various scenario analyses. The purpose of establishing a base case analysis is to determine the optimal expansion plan based on NIPSCO's current view of the future market, taking into account all reasonably foreseeable outcomes. It should be noted that the impact of a future Federal mandate to reduce carbon is included in the base case. The scenario analyses are performed in order to see how NIPSCO's optimal plan will change due to regulatory change in the market structure.

Tested Sensitivity – No Carbon Future - The no carbon cost sensitivity represents a forward view without a federal cap and trade program for carbon emissions. The revised external market prices are presented in CONFIDENTIAL Appendix F, Figure F-7.

Tested Sensitivity – Renewable - The renewable scenario is based upon a voluntary clean energy electricity standard, which was enacted in Senate Bill 251 in July 2011 that calls for a voluntary goal of producing ten percent of a participating utility's electricity from renewable energy resources by 2025. The Clean Energy Portfolio Standard ("CPS") Goal is based on NIPSCO's actual energy requirements in 2010, 16,562 GWh. If NIPSCO was to voluntarily participate, its CPS Goals are enumerated in Table 9-6.

Table 9-6
Clean Energy Portfolio Standard Goal

	CPS (%)	Energy (GWh)
2011	0%	0
2012	0%	0
2013	4%	662
2014	4%	662
2015	4%	662
2016	4%	662
2017	4%	662
2018	4%	662
2019	7%	1,159
2020	7%	1,159
2021	7%	1,159
2022	7%	1,159
2023	7%	1,159
2024	7%	1,159
2025	10%	1,656
2026	10%	1,656
2027	10%	1,656
2028	10%	1,656
2029	10%	1,656
2030	10%	1,656
2031	10%	1,656
2032	10%	1,656

Meeting the CPS Goals includes an overall incentive that may increase the shareholder's rate of return on equity by up to fifty basis points over their authorized rate of return. In addition, NIPSCO may be eligible for incentives to pay for the compliance projects. These incentives include timely recovery of costs and expenses incurred during construction and operation of compliance projects and authorization to increase the shareholder's rate of return on equity by up to three percentage points over their authorized rate of return. The IURC will adopt the rules governing the measurement and evaluation of compliance, financial incentives, rate adjustment mechanisms, application requirements and methodology, and reporting requirements.

The following NIPSCO resources are defined as Clean Energy Resources, according to Section 4 of Senate Bill 251:

- Section 4 (6): Oakdale and Norwalk hydropower resources;
- Section 4 (1): Barton and Buffalo Ridge wind resources; and
- Section 4 (16): DSM and energy efficiency initiatives.

Table 9-7 compares NIPSCO's existing Clean Energy Resources against their hypothetical CPS Goals and enumerates the percentage of Clean Energy produced in the state of Indiana. The CPS Goals requires that 50% of qualifying energy must come from within the state of Indiana.

Table 9-7
Detail of the Clean Energy Portfolio Standard Goal

	CPS (%)	Energy (GWh)	Hydro Energy (GWh)	Wind Energy (GWh)	DSM Energy (GWh)	EE Energy (GWh)	Net CPS Energy (GWh)	In State (%)
2011	0%	0	54	269	671	0	0	73%
2012	0%	0	54	269	684	96	0	76%
2013	4%	662	54	270	696	242	-599	79%
2014	4%	662	54	269	709	400	-770	81%
2015	4%	662	54	269	709	521	-891	83%
2016	4%	662	54	270	709	697	-1,068	84%
2017	4%	662	54	270	709	902	-1,272	86%
2018	4%	662	54	269	709	1,132	-1,501	88%
2019	7%	1,159	54	270	709	1,363	-1,236	89%
2020	7%	1,159	54	271	709	1,606	-1,480	90%
2021	7%	1,159	54	270	709	1,571	-1,445	90%
2022	7%	1,159	54	269	709	1,535	-1,408	90%
2023	7%	1,159	54	270	709	1,506	-1,379	89%
2024	7%	1,159	54	121	709	1,479	-1,203	95%
2025	10%	1,656	54	122	709	1,445	-674	95%
2026	10%	1,656	54	122	709	1,411	-640	95%
2027	10%	1,656	54	123	709	1,365	-594	95%
2028	10%	1,656	54	122	709	1,272	-501	94%
2029	10%	1,656	54	0	709	1,175	-282	100%
2030	10%	1,656	54	0	709	1,077	-184	100%
2031	10%	1,656	54	0	709	975	-82	100%
2032	10%	1,656	54	0	709	844	49	100%

NIPSCO could be able to meet the Indiana Voluntary CES through the year 2031 with existing Clean Energy Resources, DSM Programs (A/C Cycling and Energy Efficiency Programs).

In addition to NIPSCO's existing Clean Energy Resources, the 2011 IRP indicates the need for a Combined Cycle facility in 2023. Section 4 (21) states, "Electricity that is generated from natural gas at a facility that is constructed in Indiana after July 1, 2011, which displaces electricity generation from an existing coal fired generation facility." NIPSCO's planned 2020 CCGT meets this definition.

NIPSCO compared the production dispatch of its coal fired resources in a case with and without the 2023 Combined Cycle. In the case without the 2023 Combined Cycle, NIPSCO replaced the Combined Cycle generation with a market purchase of equivalent capacity and energy purchased from the MISO market. Table 9-8 demonstrates the effects on NIPSCO's coal-fired generation, net of off-system interchange, with and without the 2023 Combined Cycle.

Table 9-8
Energy Displacement
(GWh)

	Coal Fired Generation		Displaced
	w/o CCGT	w/ CCGT	Energy
2011	10,629	10,629	0
2012	12,071	12,071	0
2013	12,220	12,220	0
2014	14,653	14,653	0
2015	12,659	12,659	0
2016	12,254	12,254	0
2017	11,878	11,878	0
2018	11,395	11,395	0
2019	11,138	11,138	0
2020	12,343	12,343	0
2021	12,599	12,599	0
2022	12,892	12,892	0
2023	12,088	12,163	-75
2024	12,405	12,573	-168
2025	12,111	12,326	-215
2026	12,591	12,840	-249
2027	12,363	12,641	-278
2028	12,560	12,861	-302
2029	10,757	10,885	-128
2030	10,974	10,986	-12
2031	10,556	10,595	-40
2032	11,049	11,081	-32

NIPSCO's 2023 Combined Cycle qualifies as a Clean Energy Resource. However, Section 12(g) states, "A participating electricity supplier may use a clean energy resource described in section 4(a)(17) through 4(a)(21) of this chapter to satisfy not more than thirty percent (30 percent) of any of the CPS goals set forth in subsection (a)." Table 9-9 updates NIPSCO's existing Clean Energy Resources with displaced coal generation limited to 30 percent of the CPS goals.

Table 9-9
Clean Energy Portfolio Standard Goal with CCGT

	CPS (%)	Energy (GWh)	Hydro Energy (GWh)	Wind Energy (GWh)	DSM Energy (GWh)	EE Energy (GWh)	CCGT_ Energy (GWh)	CPS (%)	Net CPS Energy (GWh)	In State (%)
2011	0%	0	54	269	671	0	0	0%	0	73%
2012	0%	0	54	269	684	96	0	0%	0	76%
2013	4%	662	54	270	696	242	0	0%	-599	79%
2014	4%	662	54	269	709	400	0	0%	-770	81%
2015	4%	662	54	269	709	521	0	0%	-891	83%
2016	4%	662	54	270	709	697	0	0%	-1,068	84%
2017	4%	662	54	270	709	902	0	0%	-1,272	86%
2018	4%	662	54	269	709	1,132	0	0%	-1,501	88%
2019	7%	1,159	54	270	709	1,363	0	0%	-1,236	89%
2020	7%	1,159	54	271	709	1,606	348	30%	-1,828	91%
2021	7%	1,159	54	270	709	1,571	348	30%	-1,793	91%
2022	7%	1,159	54	269	709	1,535	348	30%	-1,756	91%
2023	7%	1,159	54	270	709	1,506	348	30%	-1,727	91%
2024	7%	1,159	54	121	709	1,479	348	30%	-1,551	96%
2025	10%	1,656	54	122	709	1,445	497	30%	-1,171	96%
2026	10%	1,656	54	122	709	1,411	497	30%	-1,137	96%
2027	10%	1,656	54	123	709	1,365	497	30%	-1,091	96%
2028	10%	1,656	54	122	709	1,272	497	30%	-998	95%
2029	10%	1,656	54	0	709	1,175	497	30%	-779	100%
2030	10%	1,656	54	0	709	1,077	497	30%	-680	100%
2031	10%	1,656	54	0	709	975	497	30%	-579	100%
2032	10%	1,656	54	0	709	844	497	30%	-448	100%

NIPSCO could meet the Indiana Voluntary CES throughout the planning horizon.

Incentives

NIPSCO's current expansion plan meets the CPS Goals in all years between 2013 and 2028 and is qualified for the financial incentives defined in Sections 11 and 13 the Senate Bill 251. Senate Bill 251 outlines two primary financial incentives available to NIPSCO's shareholders:

1) Section 11 "The Commission shall encourage clean energy projects by creating the following financial incentives for clean energy projects … The authorization of up to three (3) percentage points on the return on shareholder equity that would otherwise be allowed to be earned on project described in subdivision (1)."
2) Section 13 "an increased overall rate of return on equity, not to exceed fifty (50) basis points over a participating electric supplier's authorized rate of return whenever the participating electricity supplier attains a CPS goal set forth in section 12(a)" .

NIPSCO's 2023 Combined Cycle qualifies, under Section 4 (21), for up to three (3) percentage points on shareholder return on equity. NIPSCO's 2023 Combined Cycle is a natural gas facility, built in Indiana after July 1, 2011, and displaces electricity generation from existing coal fired generation facilities. NIPSCO qualifies, under Section 13 (a) (2), for an increased overall rate of return on equity, not to exceed fifty (50) basis points. Section 13 (a) (2) states, "in the case of a particular participating electricity supplier, be based on the extent to which the participating electricity supplier met a particular CPS goal using clean energy resource listed in Section 4(a)(1) through 4(a)(16) of this chapter." By this definition, NIPSCO's 2023 Combined Cycle contribution to the CPS goals is not eligible for this incentive. However, NIPSCO does qualify for the overall financial incentives for years 2013 through 2024. Table 9-10 enumerates the financial incentives that NIPSCO is qualified to receive.

Table 9-10
Clean Energy Portfolio Standard
Financial Incentive
Incremental Revenue Requirements
($000)

	Section 11	Section 13	Total Incentives
2011	$0	$0	$0
2012	$0	$0	$0
2013	$0	$11,845	$11,845
2014	$0	$11,845	$11,845
2015	$0	$11,845	$11,845
2016	$0	$11,845	$11,845
2017	$0	$11,845	$11,845
2018	$0	$11,845	$11,845
2019	$0	$11,845	$11,845
2020	$14,062	$15,892	$29,954
2021	$14,062	$15,754	$29,816
2022	$14,062	$15,618	$29,680
2023	$14,062	$15,480	$29,542
2024	$14,062	$15,342	$29,404
2025	$14,062	$0	$14,062
2026	$14,062	$0	$14,062
2027	$14,062	$0	$14,062
2028	$14,062	$0	$14,062
2029	$14,062	$0	$14,062
2030	$14,062	$0	$14,062
2031	$14,062	$0	$14,062
2032	$14,062	$0	$14,062
	$63,654	**$93,528**	**$157,182**

NIPSCO's 2011 recommended IRP plan provides approximately $157,182 (2011 K$) of financial incentives to shareholders for meeting the Voluntary CES. NIPSCO derives its financial incentives under Section 11, $63,654 (2011 K$), and Section 13, $93,528 (2011 K$). Furthermore, Senate Bill 251 contemplates an exchange market for Clean Energy Certificates. Section 12 (e) states that participating electricity suppliers may own or *purchase* Clean Energy Certificates ("CEC"), equal to one MWh of Clean

Energy. NIPSCO has surplus CECs from 2013 through 2032. However; NIPSCO sees very little value in surplus Clean Energy Certificates because the program is voluntary and has no penalties for failing to meet CPS goals. The only economic value to a participating electricity supplier to purchase CECs would be to meet CPS goals and earn the financial incentives defined in Section 13.

From the perspective of the NIPSCO 2011 IRP, the Voluntary CES program will have no impact on the near term. Furthermore, the base case addition of a CC in 2020 will qualify as a Clean Energy Resource because the energy displaces energy generated from existing coal fired resources

Tested Scenario – Retire Michigan City - Retire Michigan City on December 31, 2015.

Tested Scenario – Results - The results are in Table 9-11.

Table 9-11
Optimal Plan Under Various Scenarios

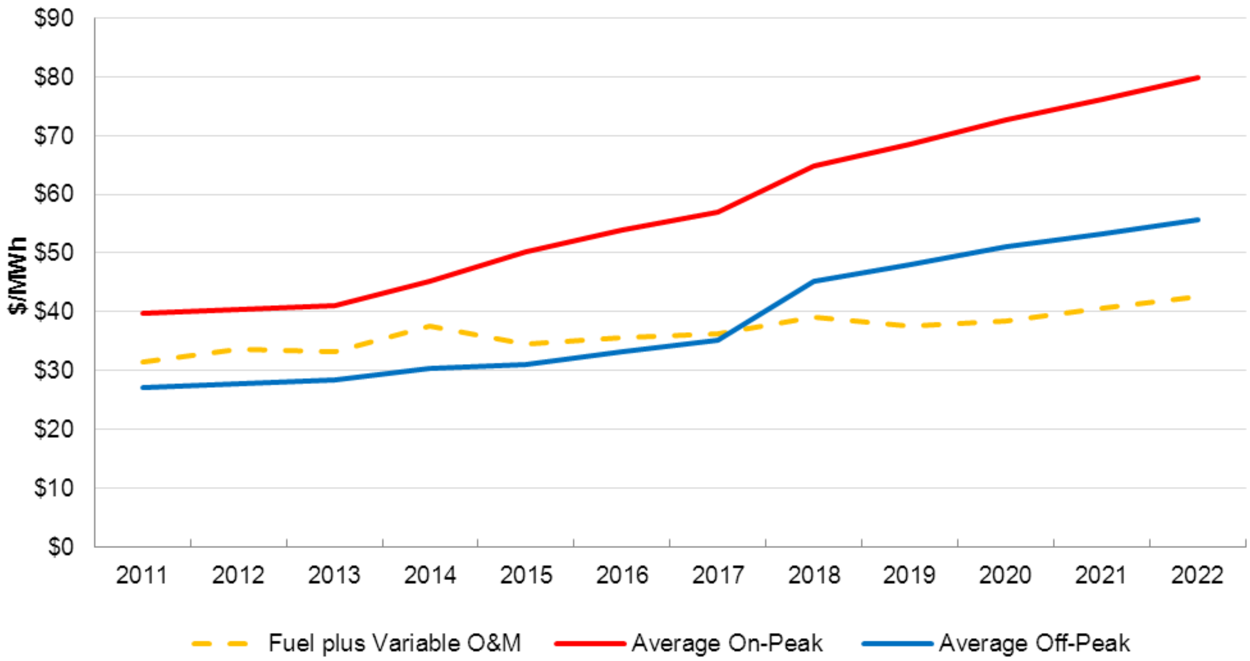
Plan	Base	No Carbon	Renewable	Retire MC
2012				
2013	Market	Market	Market	Market
2014	Market	Market	Market	Market
2015	Market	Market	Market	Market
2016	Market	Market	Market	**CCGT**
2017	Market	Market	Market	
2018	Market	Market		
2019				
2020				
2021	Market	Market		
2022	Market	Market	Market	
2023	**CCGT**	**CCGT**	**CCGT**	Market
2024				**CCGT**
2025				
2026				
2027				
2028				
2029	**CCGT**	**CT_7FA** Market	**CCGT**	
2030		**CT_7FA** Market		Market
2031				**CT_Aero** Market
2032		Market		**CT_Aero** Market
NPVUC (2011 $000)	**12,932,337**	**11,030,167**	**12,932,337**	**13,507,000**

Operational Analysis

Bailly Competitiveness

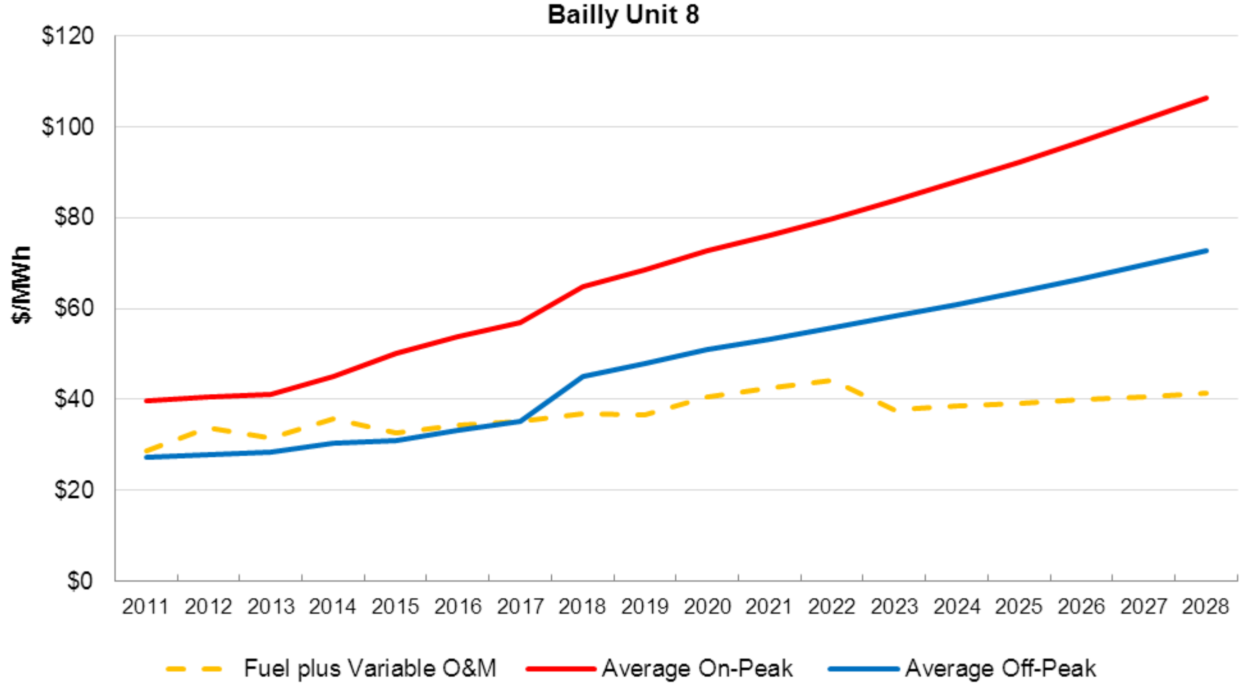
In addition to the tested sensitivities and scenarios, NIPSCO was also concerned with the competitiveness of Bailly Units 7 and 8. Figures 9-1 and 9-2, for Bailly Unit 7 and Bailly Unit 8 respectively, depict the annual average on-peak and off-peak market prices versus total unit variable cost, fuel and variable O&M.

Figure 9-1
Bailly Unit 7



Bailly Unit 7 is competitive with the on-peak market throughout the planning horizon. Bailly Unit 7 is at or below the off-peak market through 2017. Beyond 2017, Bailly Unit 7 is competitive with the off-peak market.

Figure 9-2
Bailly Unit 8



Bailly Units 7 and 8 are competitive with the on-peak market throughout the planning horizon. The units are at or below the off-peak market through 2017. Beyond 2017, both units are competitive with the off-peak market.

Interruptible Load Levels

NIPSCO's base assumption for Interruptible Load was 225 MW throughout the planning horizon. NIPSCO examined the IRP impacts of various levels of Interruptible load from 0 MW to 450 MW. The resulting plans are depicted in Table 9-12.

Table 9-12
Optimal Plan Under Various Levels of Load Management

	Interruptible Load (MW)						
	0	**75**	**150**	**225**	**300**	**375**	**450**
2012	Market	Market	Market				
2013	Market	Market	Market	Market			
2014	**CT_Aero** **CT_7FA** Market	**CT_7FA** Market	**CT_Aero(2)** Market	Market			
2015	**CT_Aero** Market	Market	Market	Market			
2016	Market	Market	Market	Market			
2017	Market	Market	Market	Market			
2018	Market	Market	Market	Market			
2019							
2020							
2021	Market		Market	Market			
2022	Market	Market	**CCGT**	Market			
2023	**Conversion** **CCGT**	**Conversion** **CCGT**		**CCGT**	**CCGT**	**CCGT**	Market
2024							**CCGT**
2025							
2026							
2027							
2028							
2029	**CCGT**	**CCGT**	**CCGT**	**CCGT**	**CCGT**	Market	
2030						**CCGT**	Market
2031							**CT_Aero** Market
2032							**CCGT**
NPVRR (2011 $000)	**13,487,656**	**13,259,471**	**13,165,581**	**12,932,337**	**12,891,518**	**12,852,681**	**12,795,917**

Examining the range of Interruptible Demand, the first incremental 75 MW is worth approximately $230 million. The second incremental 75 MW is worth approximately $94 million. The third incremental 75 MW has the highest value at $233 million. The primary driver of this value is the deferral of capital additions in the 2012 through 2022 time horizon. The remaining increments are $41 million, $39 million, and $57 million, for fourth through sixth incremental 75 MW.

Results of the Integration Process

NIPSCO has undertaken a thorough evaluation of its resource options for current and future planning. NIPSCO integrated its Demand Side Energy Efficiency programs, DLC program, and Self-Build Supply-Side Resource options to inform and determine the appropriate Short-Term Action Plan. NIPSCO's Short-Term Action Plans calls for a number of near term MISO capacity purchases for the period of 2013 through 2017 and 2022. These near term capacity purchases do not exceed 75 MW. In 2023, NIPSCO anticipates the need for a CCGT resource. The need in the longer term is one CCGT in 2029.

The nature of NIPSCO's load and resource options led to a robust need for a CCGT. NIPSCO examined the impacts of potential sensitivities and scenarios and determined that a CCGT, in the near-term, was the most economic choice. NIPSCO evaluated significantly different plans that include, in the near-term, CT and PC. None of those options were economically competitive nor did they substantially reduce NIPSCO's risk exposure.

2011

SECTION 10: TRANSMISSION AND DISTRIBUTION

NIPSCO

INTEGRATED RESOURCE PLAN

Highlights – Transmission and Distribution

- ***NIPSCO continues to invest in its existing T&D resources to ensure reliable and safe delivery of electricity from generating facilities to customers.***
- ***NIPSCO's transmission planning is integrated with regional planning and conforms to the requirements of FERC, NERC, MISO and ReliabilityFirst.***
- ***The transmission planning process is an open, transparent and collaborative process.***
- ***NIPSCO's distribution planning reviews reliability metrics and loading on its distribution facilities, and identifies the need for upgrades to support customer load growth and to address age and condition of existing facilities.***
- ***Ten transmission projects within the MISO 2009 and 2010 transmission expansion plans have been approved by the MISO Board, primarily based on age and condition, to maintain reliability of the NIPSCO system.***
- ***NIPSCO has three Multi-Value Projects pending approval by the MISO Board.***

NIPSCO assesses current physical T&D system resources for projected system conditions. This section provides background on NIPSCO's outlook for its transmission systems, its participation at MISO, and applicability of NERC standards. This section also describes system planning criteria and guidelines, transmission system assessment and T&D system improvements. NIPSCO continues to invest in its existing T&D resources to ensure reliable and safe service to customers. NIPSCO participates in planning processes at the state, regional and federal level to ensure customers' interests are represented. These processes provide for planning transparency.

NIPSCO's Transmission System Planning

NIPSCO's transmission systems projects planning have been expanded to include regional transmission projects planned through the MISO transmission expansion process. MISO has proposed a portfolio of regional transmission projects designated Multi-Value Projects ("MVPs"). NIPSCO has been actively participating in the MISO MVP Task Force since its initiation in September of 2010. NIPSCO has worked with the MISO planning team to provide project details for the three projects in the portfolio that connect to NIPSCO-owned facilities. These projects include a 345 kV circuit from NIPSCO's Reynolds to Burr Oak to Hiple substations; a portion of the 345 kV circuit from Ameren's Kansas substation that will terminate at NIPSCO's Sugar Creek substation; and a portion of the 765 kV circuit from Duke's Greentown substation that will terminate at NIPSCO's Reynolds substation. MISO anticipates sending a final draft of the 2011 Transmission Expansion Plan, which includes NIPSCO's reliability-based transmission projects as well as the MISO recommended MVPs portfolio, to the MISO Board of Directors in early November with Board approval expected early December 2011.

FERC issued Order No. 1000 on July 21, 2011 in response to its Notice of Proposed Rulemaking pertaining to Transmission Planning and Cost Allocation. Although compliance with Order No. 1000 requirements will have an impact on the future transmission planning process, transmission project approval will proceed under the current planning procedures until MISO's compliance filing is accepted.

The current due date for MISO's compliance filing for its internal planning process is October 2012. Elimination of the Right of First Refusal contained in the MISO Transmission Owners Agreement that was required by FERC in Order No. 1000 is included in a request for rehearing and clarification of the Order. NIPSCO will be participating in the development of the MISO compliance filing.

Order No. 1000 expands the requirements for interregional transmission planning. Because NIPSCO is situated on a very significant seam between MISO and PJM, NIPSCO will provide input to the stakeholder process required to modify the existing Joint Operating Agreement between MISO and PJM for compliance with Order No. 1000 which is due in April 2013. NIPSCO is also active in FERC proceedings, including the recent Notice of Intent calling for the review of the current transmission rate incentives.

MISO

NIPSCO has been a member of MISO since July 2003. NIPSCO has become a very active participant in the Transmission Owners and Stakeholder process. Since NIPSCO's last IRP, several transmission owners have joined or are in the process of joining MISO with Mid American Energy, Big Rivers Electric Corporation and Dairyland Power Cooperative being the largest of those that have joined. First Energy Corporation left MISO effective June 1, 2011 and Duke Energy - Ohio and Duke Energy - Kentucky will leave MISO effective December 31, 2011. Duke Energy - Indiana will remain in MISO. Entergy Corporation has indicated their desire to join MISO (announced for 2013.) The addition of Entergy is currently in the process of gaining state regulatory approval in the five states in which Entergy operates. With changes to the MISO footprint, there may be an expanded market for NIPSCO's generation.

Given pending environmental regulations a tighter balance between supply and demand in the MISO market is anticipated to lead to a requirement for higher reserve margins in the next five years, increasing NIPSCO's resource requirements. Both the Ancillary Services Market and demand response services are anticipated to contribute to market efficiency thereby mitigating impact. Such changes may impact the dispatch order and changes to the transmission system.

NIPSCO currently holds Chair positions in the following MISO Stakeholder community:

- Market Subcommittee
- Stakeholder Governance Working Group
- Supply Adequacy Working Group
- Data Transparency Working Group
- Credit Practices Working Group

NIPSCO continues to participate in the Reliability Subcommittee, Market Subcommittee, and all related working groups and task teams. In addition, NIPSCO has representation in the Power Marketers Sector.

NIPSCO is a very active participant in the Balancing Authority Committee and Balancing Authority Task Teams. Through these groups, NIPSCO is monitoring and assisting MISO as they perform their task as the Balancing Authority, ensuring reliability and NERC compliance.

NIPSCO is an active member of the Transmission Owners Committee and all of its related working groups and task teams, as well as MISO committees dealing with transmission policy such as the RECB Task Force and the Candidate MVP Technical Studies Task Force.

NIPSCO is active in the Planning Advisory Committee, the Planning Subcommittee and other related Subcommittees, working groups and task teams.

Through participation in the Stakeholder process, NIPSCO continues to support MISO's efforts to expand the Reliability footprint and Market footprint. NIPSCO continues to work with MISO to develop market tools that support and/or enhance reliability and the benefits to NIPSCO customers and shareholders.

NERC

NIPSCO is subject to NERC whose self-proclaimed mission is to ensure the reliability of the North American bulk power system. NERC is the Electric Reliability Organization certified by FERC to establish and enforce reliability standards for the bulk-power system. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel. NIPSCO has registered with NERC as a Distribution Provider, Generator Owner, Generator Operator, Load Serving Entity, Purchasing-Selling Entity, Resource Planner and Transmission Planner. In addition together with MISO in a Coordinated Functional Registration, NIPSCO is registered as a Balancing Authority, Transmission Operator and Transmission Owner. Each Registered Entity is subject to compliance with applicable NERC and RRO standards approved by FERC. Reliability*First* Corporation is the RRO. Non-compliance with a single standard can result in fines up to $1 million per day.

The NERC Critical Infrastructure Protection ("CIP") set of standards is a very dynamic set of regulatory requirements. After the last IRP filing the industry has seen the NERC CIP standards move from version 1 to 2 and immediately followed by a version 3 in the same year. Currently, NIPSCO is monitoring the regulatory process awaiting a final approval and implementation date of the NERC CIP version 4 and the NERC CIP version 5 set of standards.

The CIP version 4 standards received industry approval on December 30, 2010 and NERC approval on January 24, 2011. They were filed with FERC on February 10, 2011. FERC issued a Notice of Proposed Rulemaking requesting comments on September 15, 2011 and provided direct guidance on how quickly they expect CIP version 5 to be complete. After review of the comments received, NIPSCO anticipates the version 4 standards becoming effective in the first quarter of 2012. The CIP version 4 standards will expand the scope of NIPSCO identified critical assets and the identified critical cyber assets.

In relation to CIP version 5 NIPSCO is relying on the guidance from FERC that requests CIP version 5 be filed with FERC in the third quarter of 2012. The NERC CIP version 5 set of standards will significantly expand the scope of NIPSCO identified critical assets and the identified critical cyber assets.

NIPSCO anticipates cyber security regulation and cyber security risks will be an ever changing environment that demands continued focus.

NIPSCO's Transmission Planning operates within the FERC Order 890 planning procedures of MISO, NIPSCO's Transmission Planning Authority, and under the standards of the Reliability*First* Corporation, NIPSCO's RRO.

As part of the MISO transmission planning process, NIPSCO annually performs transmission system assessments on its system in compliance with NERC and applicable regional Reliability*First* Corporation standards. The Company undertakes these assessments to identify system deficiencies and to provide a basis for the development of plans to alleviate potential problems. NIPSCO submits the identified deficiencies and proposed solutions to MISO for evaluation. As part of MISO's planning process, it verifies any deficiencies in the NIPSCO system on a regional basis and either validates NIPSCO's proposed mitigation or determines a better resolution to the deficiency. In addition, MISO may identify regional transmission projects that provide a benefit to the entire MISO footprint including NIPSCO, some of which may connect to NIPSCO transmission facilities.

System Planning Criteria and Guidelines

T&D planning criteria guidelines address the following:

- Adequately serve native load customers and maintain continuity of service under various system contingencies;
- Support and contribute to the reliability of the Bulk Electric System;
- Increase availability and reliability of the system; and
- Minimize capital and operating costs while being consistent with the above guidelines.

NIPSCO Transmission Planning analyzes adequacy of system reliability for line, substation, and other system component failures, along with generation outages, and with power-importing capabilities of interconnections with other utilities. Adequacy is measured in terms of NIPSCO's design voltage and thermal requirements appearing in CONFIDENTIAL Appendix E. When a violation of the requirements is identified, Transmission Planning develops mitigations that may consist of operating measures or system improvements.

MISO Expansion Planning independently assesses the NIPSCO transmission system to observe whether NIPSCO's design voltage and thermal requirements are satisfied as well as the impact on the MISO footprint. MISO tests mitigation measures proposed by NIPSCO planning to determine whether the identified system needs are met. If MISO agrees with NIPSCO's proposed improvements, MISO Expansion Planning staff submits agreed upon transmission projects to the MISO Board for approval via the MISO Transmission Expansion Plan ("MTEP"). Once approved by the MISO Board, responsibility for the project is currently assigned to the originating transmission owner in accordance with the MISO Transmission Owners Agreement. Approved projects with longer term and/or delayed in-service dates are continually reviewed in the MTEP process. If certain tariff conditions are met, Board-approved projects qualify for cost sharing among MISO members. Note that NIPSCO does not require MISO agreement to proceed with a project if NIPSCO Transmission Planning deems it necessary, as long as that project does not harm other systems in MISO. Subsequent to Board approval, projects may be delayed or modified due to changing system conditions or better solutions becoming known.

Transmission Impact of Supply-Side Resources

Transmission system adequacy and reliability are planned without dependence on individual generation sources for supplying customer loads in MISO's open and transparent market process. While the impact of outages of individual generation sources on the NIPSCO transmission is studied, the MISO market is generally used as a supply resource.

Should a new generating facility be constructed within the MISO footprint and the generators at the facility are determined to be deliverable as Network Resources, any MISO Load Serving Entity can purchase power from the generator(s) and move it across the grid at a flat rate for transmission. This is the mechanism employed by NIPSCO, as a Load Serving Entity, to secure power from Sugar Creek which is a designated network resource within MISO.

However, various system impact studies have shown that significant new generation additions often require transmission upgrades, in transmission lines and transformers, or short circuit interrupting capability, or both. NIPSCO works with MISO on studies for generator interconnections proposing to connect to or directly impacting the NIPSCO transmission system, including generators located along seams between PJM and MISO.

Dynamic Stability studies have been performed for all NIPSCO-owned generators in conjunction with system impact studies performed for various generators considering connection to the Company transmission system. Results of these analyses indicate that all NIPSCO-owned generators are stable for all three phase and single phase faults, with delayed fault clearing for single phase faults, and with and without various other transmission facilities out of service.

Distribution Planning

NIPSCO Distribution Planning reviews distribution system adequacy for local line, substation and source feed component failures. Normal as well as contingency status facility loading and voltage operating characteristics are analyzed for adequacy along with local and system wide reliability metrics (i.e. CAIDI, SAIDI, SAIFI). System improvements are based on mitigation of capacity, voltage and reliability deficiencies. System upgrades also consider customer load growth, and address age and condition of existing electric infrastructure such as poles, underground cables, breakers, transformers.

Distribution Planning anticipates some impact on overall system loading due to increased activities of customer-owned generation installations associated with the new net metering and feed-in tariff pilot programs which were recently put into effect. These programs are discussed further below under Evolving Technologies. The magnitude of the impact and associated reduction in system demand will depend upon the demonstrated performance and reliability of the various installed generating resources which includes solar, wind, hydro and bio mass based generation sources. Differences in operational characteristics, performance, timing and locations for these diverse types of customer owned generation will affect the levels of customer dispatched power, and consequently vary the impact on distribution system loading at any given time.

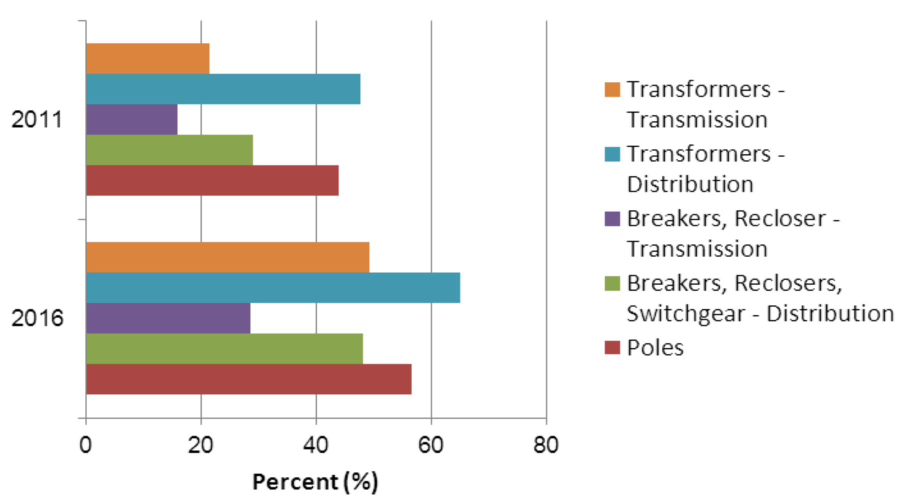
Transmission System Assessment

In the NIPSCO 2011 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (CONFIDENTIAL Appendix E), Part 2 contains the regional power flow study, available through the Reliability*First* Corporation. The study includes solved real and reactive flows, voltages, detailed assumptions, sensitivity analyses and model description. Part 3 includes applicable transmission maps. Part 4 describes the reliability criteria used for transmission planning. Part 5 presents the assessment practice used. Part 6 contains an evaluation of the reliability criteria in relation to the present performance and the expected performance of the NIPSCO transmission system.

Transmission System Capital Improvements

Since NIPSCO's last IRP, there have been 10 transmission projects included in Appendix A of the 2009 and 2010 MTEPs that have been approved by the MISO Board. Of these 10, one has been eligible for cost allocation under the MISO Tariff: a 345 kV / 138 kV transformers at Green Acres substation. The majority of NIPSCO's transmission projects approved in the MTEP have been justified by age and condition to maintain the reliability of the NIPSCO system. As illustrated in Figure 10-1 below, a substantial increase in the percentage of NIPSCO's equipment that is over 40 years old will be seen over the next five years for both T&D assets.

Figure 10-1
Age of Equipment
Percentage at 40 Years or More for Named Year in Service



Units in Service in 2011

Transformers	Transmission	503	Distribution	314
Breakers , Recloser, Switchgear	Transmission	591	Distribution	1,297
Poles			Distribution	368,192

NIPSCO's FERC complaint, ER05-103, identified certain system upgrades within NIPSCO that would be required to relieve congestion resulting from ComEd's joining PJM. In the complaint, NIPSCO specified that it was willing to make the upgrades but NIPSCO customers shouldn't bear the cost of those upgrades. In 2009, a PJM market participant approached NIPSCO and MISO and proposed to fund these upgrades. As specified in an agreement with this market participant, NIPSCO upgraded a Michigan City 138 kV breaker to relieve congestion on the Dune Acres – Michigan City 138 kV circuits for the loss of the ComEd Wilton Center – AEP Dumont 765 kV circuit. In addition, NIPSCO upgraded substation facilities at our Sheffield and Wolf Lake substations to increase circuit ratings beyond that provided by the reconductoring of the Sheffield – Wolf Lake – ComEd State Line 138 kV circuit that was needed by NIPSCO to meet increased customer loads. These substation improvements would relieve congestion on the Wolf Lake – ComEd State Line 138 kV circuit for the loss of the Sheffield – ComEd Burnham 345 kV circuit. Both of these facilities had been high on the list of MISO congestion points.

NIPSCO has recently been engaged by some PJM and MISO market participants to perform incremental upgrades on its transmission system to accommodate higher west to east economic transfers. These types of upgrades to NIPSCO's system have been studied by MISO in the past, most recently in its "Cross Border Top Congested Flowgate Study," part of its 2010 MTEP. MISO determined in this study that while there were economic benefits to these types of projects in the NIPSCO system, the majority of the benefits would be realized by non-MISO entities, thus causing these projects to fail the test for economic cost recovery under MISO's criteria for market efficiency projects. Although these projects do not qualify for cost sharing under the current MISO/PJM tariffs, market participants do see sufficient benefits for themselves in seeing these projects being built and are willing to consider alternative methods for NIPSCO to recover its revenue requirements than the standard MISO cost recovery mechanisms. NIPSCO is working toward getting this issue addressed through the MISO stakeholder process and moving it forward. NIPSCO is committed to helping find a solution that improves market efficiencies in both MISO and PJM through building these projects, but at the same time ensuring that the beneficiaries of these projects pay their share of the project costs.

A MISO stakeholder task force is currently updating the 2009 congestion analyses with the expectation that identified projects meeting a revised benefit cost ratio criteria would be approved by the MISO Board in June 2012. NIPSCO is actively participating in this MISO stakeholder process as well as external processes that identify NIPSCO projects that impact congestion within PJM.

In July 2010, MISO filed revisions to its tariff that introduced a new category of transmission projects called Multi-Value Projects ("MVPs"). Essentially, MVPs would be larger regional transmission projects to meet certain policy, reliability and / or economic criteria. Based on prior Regional Generator Outlet Studies as well as other congestion and generator interconnection studies, MISO included an initial portfolio of "starter" projects. With the formation of the stakeholder based Candidate Multi Value Project Portfolio Technical Studies Task Team and subsequent analyses, MISO has finalized a recommended portfolio of MVPs for MISO Board approval in December 2011. These projects enable MISO members to meet renewable portfolio standards and goals and will also reduce congestion and enhance the reliability of the transmission grid. Three of these MISO recommended projects connect to NIPSCO-owned facilities including: 1) A Reynolds – Burr Oak – Hiple 345 kV circuit with additional interconnections to AEP at Reynolds and Hiple; 2) In conjunction with Duke, a 765 kV circuit from Reynolds to Duke's Greentown substation with a 765 kV / 345 kV transformer at Reynolds substation; 3) In conjunction with

Ameren, a 345 kV circuit from Sugar Creek to Ameren's Kansas substation. NIPSCO is working closely with MISO on the project details for the business case justification of these projects.

Evolving Technologies and System Capabilities

It is expected that any effort that would reduce peak demand would postpone transmission system capacity increases. In the future, demand-side resources could be very effective if utilized and could be targeted at areas in need of a transmission capacity increase. Because not all areas of the transmission system need capacity increases at the same time, it would be much more effective to concentrate DSM load shedding in areas anticipated to be needing facility expansion or upgrading in the near future.

Pending approval from FERC of MISO's tariff changes, NIPSCO will offer DRR-1-Energy Only and EDR-Energy Only programs because NIPSCO desires to offer programs where there is existing customer interest and the Company has readily-available resources to assure a successful program. NIPSCO will continue to work with its customers to review such options and develop corresponding tariffs that would facilitate their participation. The Company expects to review such options after customers have had the ability to participate and possibly incorporate any further options in time for the 2012-2013 MISO planning year. Additionally, as required by the Commission's Order in Cause No. 43566-MISO 1, NIPSCO will review the tariffs after two full summers of participation and will include participants and interested parties. NIPSCO will then submit a report to the Commission detailing the experience, costs and expenses associated with the Rider, along with details regarding the administrative charges collected. For the summer of 2011, NIPSCO registered 172.8 MW in the DRR-1 program and 185.8 in the EDR option. NIPSCO looks to add additional commercial and industrial customers and plans to add a capacity program as customer interest and market forces permit.

As part of the long term view, NIPSCO is currently assessing and evaluating the benefits of smart grid technology. NIPSCO will assess deployment of smart grid technology based upon development of reasonable business cases.

Net Metering is an electricity policy for consumers who own renewable energy facilities (such as wind, solar and hydro power). Net metering is used as an incentive for customers to install renewable energy systems by reimbursing them for their generation output at retail rates for energy in excess of their buildings' base load electricity purchase from the utility. The recently expanded and approved program increased participation limits to less than or equal to 1 MW of nameplate capacity on a single site location, and is now available to all customer classes. The new net metering program cap may be limited to 1 percent of the Company's most recent summer peak load, with at least 40 percent of the capacity reserved for participation by residential customers.

Feed-In Tariff (renewable energy payments) is a policy mechanism designed to encourage the adoption of renewable energy sources and to help accelerate the move toward grid parity for renewable energy sources. The feed-in tariff that NIPSCO implemented in July, 2011 is capped at 30 MW of total participation. In order to ensure smaller project participation in the program, 500 kW each is reserved for wind and for solar sources, and would be applied to less than or equal to 10 kW rated projects. The tariff provides developers with a predictable purchase price for self-generation under a long-term arrangement of up to 15 years so that financing opportunities can be supported. In addition, the amount of any one technology within the 30 MW cap is limited to no more than 50% of the cap. The feed-in tariff is available to qualified wind, solar, hydro and biomass renewable generators. Applications submitted under the new feed-in tariff include: twenty-seven solar projects totaling in excess of the 15 MW cap; seven wind projects totaling 3 MWs of installed capacity; five biomass projects totaling 8.5 MWs of generation capability. A total 3.6 MWs of qualified renewable generation projects have been approved for installation, to date.

Distribution Automation ("DA") can be defined as the coordinated automatic control of substation breakers and interrupting-type line switches within an electric distribution system, along with the centralized retrieval of associated operating data for control and monitoring purposes.

NIPSCO's DA system enables specific control and the automatic isolation of electric distribution line faults and the restoration of customer service for a portion of 12.5 kV circuit outages. This is accomplished through the independent sectionalizing of individual circuits using automatic line switches and computer-controlled substation breakers. Automatic restoration also increases distribution system reliability by reducing the number of customers experiencing a sustained outage. Besides the quick restoration of electric service, the real-time operating data retrieved and stored by the DA System can provide timely and accurate outage-related information to the restoration team, speeding up problem identification for quicker overall repair time and further improvement in system reliability factors. An added benefit of real-time data retrieval and device remote control is the more effective use of labor resources for the operation and maintenance of the electric distribution system.

NIPSCO currently utilizes distribution automation control on 25 percent of its distribution substations and 20 percent of its total distribution circuit population. All new distribution substation facilities and circuits are constructed and equipped for distribution automation. As part of annual capital investments, existing older distribution facilities continue to be reviewed and upgraded to include distribution automation.

Subsequent to receiving comments on its Notice of Proposed Rulemaking on Transmission Planning and Cost allocation, FERC issued Order No. 1000 addressing various aspects of intra and inter-regional transmission planning. NIPSCO's membership in MISO and its participation in the MISO planning transmission planning process, already meets many of Order No. 1000 requirements including participation in a regional planning process that includes planning for reliability, economic and policy based projects. The Company anticipates participating in the discussions between MISO and all interconnected RTOs and planning regions that will be needed to formalize the joint planning and cost allocation requirements of Order No. 1000. Since FERC specified that the planning requirements of Order No. 1000 won't apply until the applicable compliance filings are filed and approved, it is expected that the current MTEP will be approved by the MISO Board and implemented according to the MISO Transmission Owners Agreement ("TOA"). Under the TOA, the owners of the transmission facilities to which the new transmission projects connect are responsible for their construction. The TOA does provide for circumstances where the primary owner is unable or unwilling to construct. However, Order No. 1000 required the removal of all such "right of first refusal" provisions in agreements such as the TOA or the MISO Tariff other than for upgrades to existing facilities and use of existing right of way. Order No. 1000 requires the regional planning authorities such as MISO to develop a methodology for selecting who will construct the new transmission facilities selected for construction in the planning process. NIPSCO is concerned about the implications this new rule will have on transmission projects needed to maintain system reliability. Should a third party that was assigned a reliability project in the NIPSCO system not complete the project when needed; it would put our customers at risk and could expose NIPSCO to violation of NERC standards and subsequent NERC fines. NIPSCO has joined other transmission owners within MISO to ask FERC to reconsider this part of Order No. 1000.

It is anticipated that once inter-regional transmission planning processes are in place, there may be cross-border transmission projects identified in the joint planning process. NIPSCO will incorporate such projects in its planning processes and the identification of future needs in its IRP analyses.

SECTION 11: 2011 INTEGRATED RESOURCE PLAN

NIPSCO

Highlights – 2011 Integrated Resource Plan

- ***NIPSCO's long-term planning process looks for safe, reliable, low cost solutions to meet customers' future energy needs.***
- ***The long-term plan identified capacity needs starting in 2013; NIPSCO may be able to meet its projected capacity needs with additional interruptible service and when needed, will purchase capacity until 2023, when NIPSCO anticipates the need for a CCGT. Another CCGT may be needed in 2029.***
- ***NIPSCO's Short-Term Action Plan for the years 2012 and 2013, NIPSCO will utilize available interruptible resources and continue to purchase short-term capacity as needed to meet its requirements.***
- ***NIPSCO continues to monitor variables that contribute to uncertainties and impact the resource plan.***

The long-term strategic plan identifies customer and resource needs over a twenty-year planning horizon, and recommends a potential resource portfolio to reliably and cost-effectively meet customers' future needs. A Short-Term Action Plan identifies the steps the Company will take during 2012 and 2013 to implement the strategic plan. The plan provides for compliance with applicable mandates and policies, and uses a balanced approach to manage cost, risk, uncertainty and reliability elements. In the following paragraphs, NIPSCO discusses the long-term plan and the Short-Term Action Plan.

NIPSCO's Long Term Plan

NIPSCO forecasted that its total energy and peak hour demand would grow by approximately 0.6 percent compounded annually over the study period, which identified its capacity needs over the study period. NIPSCO adjusted its peak hour demand to reflect impacts of projected interruptible services and DLC program results. NIPSCO included savings estimated from its approved DSM programs in its forecast. NIPSCO's adjusted peak hour demand by 3.81 percent to meet MISO's planning reserve margin requirements based on UCAP, which is roughly equivalent to a traditional planning reserve margin of 9 percent to 12 percent based on Installed Capacity.

NIPSCO evaluated resource options to determine the combinations of supply-side, demand-side, self-build and market resources to meet its capacity needs. NIPSCO performed sensitivity analyses for different economic, environmental, cost, risk, and regulatory uncertainty. The optimal plan was identified. The plan identified that additional capacity purchases are needed beginning in 2013. NIPSCO may be able to meet its projected capacity needs with additional interruptible service. If such resources are not available, NIPSCO will supplement its capacity needs with either through the proposed MISO Capacity Auction or bi-lateral contracts. The near term capacity needs for the period of 2013 through 2017, and for 2022 do not exceed 75 MW. In 2023, NIPSCO anticipates the need for a CCGT resource. The need in the longer term is one CCGT in 2029. Table 11-1 summarizes the plan.

Table 11-1
Assessment of Resources vs. Demand Forecast

	(a)	(b)	(c)	(d)	(e)	(f)	
	Unforced Capacity	**Internal Peak**	**Interruptible**	**Direct Load Control**	**Internal Peak Minus Interruptible**	**Internal Peak after adjustments Plus Reserve Margin**	**Capacity Position Long/Short**
Year	**(UCAP)**	**(FP07a11)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**
					(b) - (c) - (d)	(e) x 1.0381	(a) - (f)
2011	3,085	3,127	175	11	2,941	3,053	32
2012	3,098	3,214	225	23	2,966	3,079	19
2013	3,112	3,299	225	34	3,039	3,155	43
2014	3,104	3,307	225	46	3,037	3,152	48
2015	3,104	3,320	225	46	3,049	3,166	62
2016	3,104	3,314	225	46	3,043	3,159	56
2017	3,104	3,293	225	46	3,023	3,138	34
2018	3,104	3,272	225	46	3,001	3,116	12
2019	3,104	3,247	225	46	2,976	3,089	15
2020	3,092	3,222	225	46	2,951	3,064	28
2021	3,092	3,269	225	46	2,998	3,112	20
2022	3,092	3,310	225	46	3,039	3,155	63
2023	3,613	3,344	225	46	3,073	3,190	422
2024	3,613	3,383	225	46	3,112	3,231	382
2025	3,613	3,423	225	46	3,153	3,273	340
2026	3,613	3,465	225	46	3,194	3,316	297
2027	3,613	3,509	225	46	3,238	3,361	251
2028	3,613	3,565	225	46	3,294	3,420	193
2029	3,960	3,617	225	46	3,346	3,474	486
2030	3,960	3,670	225	46	3,399	3,529	431
2031	3,960	3,732	225	46	3,462	3,593	367
2032	3,960	3,796	225	46	3,525	3,659	301

Notes:

1. Internal Peak and Interruptible for 2011 reflect actual.

2. Reserve Margin for 2011 - 2032 is 3.81%

3. UCAP reflects units retiring after the peak season in the years - 2013, 2019, 2022, and 2028

4. Wind Contracts are not included in UCAP

5. UCAP is a NIPSCO estimated value

6. UCAP in 2023 and 2029 reelects the addition of a CCGT.

NIPSCO determined the types of resources that would need to be acquired to serve customers during the twenty-year study period through its planning process. This plan is based upon the most current information available. NIPSCO will seek regulatory approval to bring new resources into its portfolio as appropriate.

Given the numerous variables that contribute to uncertainty in NIPSCO's 2011 IRP, results are subject to change based on updated information. NIPSCO will continue to evaluate its resource plan as necessary. The IRP is part of NIPSCO's ongoing business process; new information is processed as it becomes available. The plan is forward looking and organic.

Short-Term Action Plan

The Short-Term Action Plan identifies the steps the Company will take during 2012 and 2013 to implement NIPSCO's long-term resource plan. In the years 2012 and 2013, NIPSCO will utilize available interruptible resources and continue to purchase short-term capacity as needed to meet its requirements. NIPSCO will continue to monitor changes in business conditions that may affect the plan.

List of Acronyms

BART	Best Available Retrofit Technology
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAPs	Community Advisory Panels
CATR	Clean Air Transport Rule
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Days
CFL	Compact Fluorescent Lighting
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CPI	Consumer Price Index
CPS	Clean Energy Portfolio Standard
CSAPR	Cross-State Air Pollution Rule
CSR	Customer Service Representative
CT	Combustion Turbine
CWA	Clean Water Act
DFGD	Dry Flue Gas Desulfurization
DLC	Direct Load Control
DLN	Dry Low NO_x
DRR	Demand Response Resource
DSM	Demand-Side Management
EDR	Emergency Demand Response
EEMS	Emission-Economic Modeling System
EGU	Electric Generating Unit
EIA	Energy Information Agency
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GHG	Green House Gases
GWh	Gigawatt hours
HAP	Hazardous Air Pollutant
HCI	Hydrogen Chloride
HDD	Heating Degree Days
Hg	Mercury
ICR	Information Collection Request
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
IVR	Interactive Voice Response
kW	Kilowatts
kWh	Kilowatt hours
LMP	Locational Marginal Price
LNB	Low NO_X Burners
MACT	Maximum Achievable Control Technology
MAE	Mean Absolute Error
MISO	Midwest Independent Transmission System Operator, Inc.
MPCP	Multi-Pollutant Compliance Plan
MTEP	MISO Transmission Expansion Plan

MW	Megawatts
MWh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NDC	Net Demonstrated Capability
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NIPSCO	Northern Indiana Public Service Company
NOAA	National Oceanic and Atmospheric Administration
NODA	Notice of Data Availability
NO_x	Nitrogen Oxide or Oxides of Nitrogen
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirements
O&M	Operating and Maintenance
OFA	Over-Fire Air
PC	Pulverized Coal
PJM	PJM Interconnection LLC
PM	Particulate Matter
PPA	Purchased Power Agreement
PRB	Powder River Basin
RCRA	Resource Conservation and Recovery Act
RFP	Request for Proposals
RIM	Ratepayer Impact Measure
RRO	Regional Reliability Organization
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
T&D	Transmission and Distribution
TOA	Transmission Owners Agreement
TPA	Third Party Administrator
UCAP	Unforced Capacity
WECC	Wisconsin Energy Conservation Corporation
WFGD	Wet Flue Gas Desulfurization

Definitions

Allowance - the authorization by the EPA/IDEM under a promulgated emissions trading program to emit up to one unit of pollutant during or after a specified calendar year or control period. Regulations for emission trading programs are currently in place or under development in Indiana for SO_2, NO_x (annual and ozone season) and Hg.

Avoided Cost - the cost of fuel, operation, maintenance, purchased power, labor, capital, taxes, and other costs not incurred by a utility if an alternative supply or demand-side resource is included in the utility's IRP.

Clean Air Act Amendments of 1990 ("CAAA") - Title IV, Acid Deposition Control, of the federal Clean Air Act Amendments of 1990, 42 U.S.C. 7401 to 42 U.S.C. 7671(q), in effect November 15, 1990.

Cogeneration Facility - 1) a facility that simultaneously generates electricity and useful thermal energy and meets the energy efficiency standards established for a cogeneration facility by the FERC under 16 U.S.C. 824a-3, in effect November 9, 1978; 2) the land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; 3) the transmission or distribution facility necessary to conduct the energy produced by the facility to a user located at or near the project site.

Compliance Screen – the process to ensure that all RFP respondents meet the initial conformance requirements. The initial conformance requirements include a timely response with all required forms filled out in their entirety and a proposal signed by a duly authorized officer or agent.

Conservation - the amount of energy saved by a customer for a specific end-use.
Conservation includes behavior changes such as thermostat setback. Conservation does not include changing the timing of energy use, switching to another fossil fuel source, or increasing off-peak usage.

Cooling Degree Day ("CDD") – A form of Degree Day used to estimate energy requirements for air conditioning or refrigeration. Typically, CDD are calculated on how much warmer the mean temperature at a location is than 65 degrees F on a given day. For example, if a location experiences a mean temperature of 75 degrees F on a certain day, there were 10 CDD that day because 75- - 65 = 10.

Critical Peak Pricing ("CPP") - CPP rates are a hybrid of the TOU and RTP design. The timing and setting of the critical peak period is based on system needs or high wholesale prices. It is similar to TOU, but a provision is made for replacing the normal peak price with a much higher critical peak price under specified trigger conditions (e.g., when system reliability is compromised or supply prices are very high).

Degree Day – a measure that gauges the amount of heating or cooling needed for a building using 65 degrees as a baseline. Electrical, natural gas, power and heating, and air conditioning industries utilize heating and cooling degree information to calculate their needs. For more specific definitions on how to calculate degree days, see definitions for
CDD and HDD.

Demand Bidding/Buyback ("DB") - a Demand Response program that allows customers to bid load reductions into utility or ISO/RTO markets. If their bids are accepted, they are obligated to curtail.

Demand-Side Management ("DSM") - the planning, implementation, and monitoring of a utility activity designed to influence customer use of electricity that produces a desired change in a utility's load shape. DSM includes only an activity that involves deliberate intervention by a utility to alter load shape.

Demand-Side Measure - a particular end-use device, technology, service, or rate design at a targeted customer's premises or a utility's energy delivery system for a specific DSM program.

Demand-Side Program - a utility program designed to implement a demand-side measure.

Demand-Side Resource - a resource that reduces the demand for electrical power or energy by applying a demand-side program to implement one (1) or more demand-side measures.

Demand Response – programs designed to encourage customers to modify the timing and level of electricity demand from their normal consumption patterns in response to:

a. changes in the price of electricity over time, or
b. incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Discount Rate - the interest rate used in determining the present value of future cash flows.

End-Use - the light, heat, cooling, refrigeration, motor drive, microwave energy, video or audio signal, computer processing, electrolytic process or other useful work produced by equipment using electricity.

Energy Efficiency - reduced energy use for a comparable level of energy service.

Energy Service - the light, heat, motor drive or other service for which a customer purchases electricity from a utility.

Engineering Estimate - an estimate of energy (kWh) and demand (kW) impact resulting from a demand-side measure based on an engineering calculation procedure. An engineering estimate addresses change in energy use of a building or system resulting from installation of a DSM measure. If multiple DSM measures are installed, an engineering estimate accounts for the interactive effect between the DSM measures.

Heating Degree Days (“HDD”) – a form of degree day used to estimate energy requirements for heating. Typically, HDD are calculated as how much colder the mean temperature at a location is than 65 degrees F on a given day. For example, if a location experiences a mean temperature of 55 degrees F on a certain day, there were 10 HDD that day, because 65 – 55 = 10.

Integrated Resource Plan (“IRP”) - a utility's assessment of a variety of demand-side and supply-side resources to cost-effectively meet customer electricity service needs. The IRP usually includes an analysis of the uncertainty and risk posed by different resources and external factors.

Load Research - the collection of electricity usage data through a metering device associated with an end-use, a circuit, or a building. The metered data is used to better understand the characteristics of electric loads, the timing of their use, and the amount of electricity consumed by users. The data may be collected over a variety of time intervals, usually sixty (60) minutes or less.

Load Shape - the time pattern of customer electricity use and the relationship of the level of energy use to a specific time during the day, month, and year.

Major Industrial - transmission voltage customers (22 in 2009) who account for over 70% of the NIPSCO industrial segment energy consumption, about 40% of system energy sales and 30% of internal peak hour demand. The NIPSCO Major Accounts - Transmission department surveys these customers and discusses the outlook for their business before providing input to NIPSCO’s forecast.

Non-Utility Generator (“NUG”) - a facility for generating electricity that:

1. is not exclusively owned by a public utility;
2. operates connected to an electric utility system; and

3. sells electricity to a utility for resale to retail customers.

Participant - a utility customer participating in a utility-sponsored DSM program.

Participant Test - a cost-effectiveness test that measures the difference between the cost incurred by a participant in a demand-side program and the value received by the participant. A participant's cost includes all costs borne by the participant. A participant's value from a DSM program consists of only the direct economic benefit received by the participant.

Penetration - the ratio of the number of a specific type of new program units installed during a given time period to the total number of new program units installed over the program's total implementation time period.

Planning Reserve Margin – additional resources required above those needed to directly serve the load required to cover operating reserves, load forecast errors, and scheduled and forced outages.

Present value - today's value of a future payment, or stream of payments, discounted at some appropriate compound interest or discount rate.

Program Cost - all expenses incurred by a utility in a given year for operation of a DSM program whether the cost is capitalized or expensed. An expense includes, but is not limited to, the following:

1. Administration.
2. Equipment.
3. Incentives paid to program participants.
4. Marketing and advertising.
5. Monitoring and evaluation.

Ratepayer Impact Measure ("RIM") Test - a cost-effectiveness test that analyzes how a rate for electricity is altered by implementing a DSM program. This test measures the change in a revenue requirement expressed on a per-unit of sale basis.

Real Time Pricing ("RTP") - a retail rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. RTP prices are typically known to customers on a day-ahead or hour-ahead basis.

Renewable Resource - a generation facility or technology utilizing a fuel source such as, but not limited to, the following: Wind; Solar; Geothermal; Waste; Biomass; and, Small Hydro.

Resource - a facility, project, contract, or other mechanism used by a utility to provide electric energy service to the customer.

Saturation - the ratio of the number of a specific type of similar appliance or equipment used to serve a particular end-use to the total number of customers in that class or the total number of similar appliances or equipment serving that end-use.

Screening - an evaluation performed by a utility to determine whether a demand-side or supply-side resource option is eligible for potential inclusion in the utility's IRP.

Short-Term Action Plan - a schedule of activities and goals developed by a utility to begin efficient implementation of its IRP. For the purposes of this IRP, Short-Term is defined as the period 2011-2014.

Standard Industrial Classification ("SIC") - a system developed by the United States Department of Commerce for use in the classification of establishments by type of activity in which engaged, for purposes of facilitating the collection, tabulation, presentation and analysis of data relating to establishments, and for promoting uniformity and comparability in the presentation of statistical data collected by various agencies of the United States Government, state agencies, trade associations, and private research organizations.

Supply-Side Resource - a resource that provides a supply of electrical energy or capacity, or both, to a utility. A supply-side resource includes the following:

1. A utility-owned generation capacity addition.
2. A wholesale power purchase from another utility or non-utility generator.
3. A refurbishment or upgrading of an existing utility-owned generating facility.
4. A cogeneration facility.
5. A renewable resource technology.

Time-of-use ("TOU") Rate - a rate with different unit prices for usage during different blocks of time, usually defined for a 24 hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. Daily pricing blocks might include an on-peak, partial-peak, and off-peak price for non-holiday weekdays, with the on-peak price as the highest price, and the off-peak price as the lowest price.

Total Resource Cost ("TRC") Test - a cost-effectiveness test that eliminates the distinction between a participant and non-participant by analyzing whether a resource is cost-effective based on the total cost and benefit of the program, independent of the precise allocation to a shareholder, ratepayer, and participant.

Threshold Screen - the process to ensure that all RFP respondents meet the minimum requirements described in the RFP. RFP proposals that have passed this screen meet the information requirements and other condition specified in the RFP.

Utility Cost Test - a cost-effectiveness test designed to minimize the net present value of a utility's revenue requirements. Also known as a revenue requirements test.

Voluntary Emergency Demand Response – programs that will pay customers to curtail when directed, but they do not have any obligation to curtail.

Index by Commission Rule 170 IAC 4-7

170 IAC 4-7 Reference	Description	Reference
4.1	External data sources	Section 3, p24
4.2	Description of effort to develop and maintain a database of electricity consumption	Section 4, p30
4.3	Proposed Schedule to obtain appliance, saturation, and consumption patterns	Section 4, p31
4.4	Discussion of customer self-generation	Section 4, p30
4.5	Description of model structure and evaluation of model performance	Section 4, pp28-32 & 36-37
4.6	Discussion of alterative forecast scenarios	Section 4, pp32-35
4.7	Description of fuel inventory and procurement planning practices	Section 5, pp48-51
4.8	Description of SO_2 emission allowance inventory and procurement planning practices	Section 8, pp81-84
4.9	Description of generation expansion planning criteria	Section 7, pp69-70
4.10	Regional power flow study	Appendix E
4.11	Dynamic stability study	Appendix E
4.12	Transmission Maps	Appendix E
4.13	Reliability criteria for transmission planning	Section 10, pp115-116 Appendix E
4.14	Evaluation of reliability criteria for transmission planning	Appendix E
4.15	Description of effort to develop and improve the methodology and data for evaluating a resource option's contribution to system wide reliability	Appendix E
4.16	Explanation of the avoided cost calculation	Section 5, p52
4.17	Hourly System Demand (in lieu of Hourly System Lambda) of the most recent historical year	Appendix B
4.18	Description of public participation procedure, if used.	Section 2, pp17-20
5(a)	Analysis of historical and forecasted levels of peak demand	Section 4, pp32-33
5(b)	Three Alternative Forecasts of peak demand and energy usage	Section 4, pp32-35
6(a)1	Existing Resources - net dependable capacity	Section 5, p46
6(a)2	Existing Resources - expected changes	Section 5, pp40-44
6(a)3	Existing Resources - fuel price	Section 5, pp47-51 Appendix F
6(a)4	Existing Resources - Environmental effects	Section 5, pp40-44 Section 8, pp72-86
6(a)5	Existing Resources - import and export transactions	Section 5, p45
6(a)6	Analysis of existing transmission system	Appendix E
6(a)7	Discussion of DSM programs	Section 5, pp52-58
6(b)1	DSM - Description of programs considered	Section 5, pp52-58

170 IAC 4-7 Reference	Description	Reference
6(b)2	DSM - Strategies to capture lost opportunities	Section 5, p52
6(b)3	DSM - Avoided Cost Projection	Section 5, p52
6(b)4	DSM - Customer Class affected by program	Section 5, p52
6(b)5	DSM - Bill reduction and participation incentive	Section 5, p52
6(b)6	DSM - Program cost to be borne by participant	Section 5, p52
6(b)7	DSM - Estimated energy and demand savings per participant	Section 5, p52
6(b)8	DSM - Estimated program penetration rate	Section 5, p52
6(b)9	DSM - Impact of program	Section 5, p52
6(c)1	Supply-Side - Resources Considered	Section 7, pp63-64
6(c)2	Supply-Side - Environmental Effects	Section 1, p15 Section 5, pp40-44 & Section 8, pp72-81
6(c)3	Supply-Side - Conformance to CAA	Section 8, pp73-81
6(c)4	Supply-Side - Joint Development Discussions	Section 2, pp19-20 & Section 5, pp51-52 & Sec 10, pp114-115
6(d)1	Transmission - Analysis of network capability	Appendix E
6(d)2	Transmission - Principal Criteria	Appendix E
6(d)3	Transmission - Expansion and Alternative options considered	Appendix E
6(d)4	Transmission - Cost of expected expansion and alternation of the network	Appendix E
7(a)	Initial screening of future resource alternatives	Section 7, pp64-68
7(b)	Cost-Effectiveness of DSM options	Section 5, p52
7(c)	DSM - NPV of program impact over the life cycle of the impact.	Section 5, p52
7(d)1	DSM - Components of benefits and the cost of each of the major tests	Section 5, p52
7(d)2	DSM - Equations used to express result	Section 5, p52
7(e)	Where it is difficult to establish an estimate of the load impact, the cost-effectiveness tests are not required.	N/A
7(f)	RIM test must be applied to a load building program	Section 5, p52
8.1	Describe the resource plan	Section 11
8.2	Identify variables, standards of reliability and other assumptions expected to have the greatest effect on the least-cost plan	Section 9, pp94-96
8.3	Present Value Revenue Requirements stated in total dollars and dollars per kilowatt hour	Section 9, p110
8.4	Demonstrate resource plan's use of all economical load management, conservation, renewable, cogeneration, and energy efficiency	Section 9, pp99-110

170 IAC 4-7 Reference	Description	Reference
8.5	Discussion of risk and uncertainties	Section 1 & Section 9, pp99-111
8.6	Demonstrate that the most economical source of supply-side resources has been used.	Section 9, pp96-111
8.7	Evaluation of dispersed generation and DSM programs including their impact	Section 9, pp93-111
8.8	Financial impact of acquiring future resources	Section 9, pp96-99
8.9	Identify and explain assumptions concerning existing and proposed regulations, laws, practices, and policies made concerning decisions used in formulating the IRP.	Section 8 & Section 9, pp102-107
8.10	Demonstrate that the resource plan incorporates a workable strategy for reacting to unexpected changes.	Section 9, pp99-111
9.1	Short-term Action Plan that covers two years	Section 11, p126
9.2	Participation of small business	Section 5, pp53-54, 57 & Section 10, 120-121
9.3	Implementation schedule of DSM programs	Section 5, pp52-58
9.4	Timetable for implementation	Section 5, pp52-58
9.5	Detailed budget for cost to be reviewed	Section 11, p126

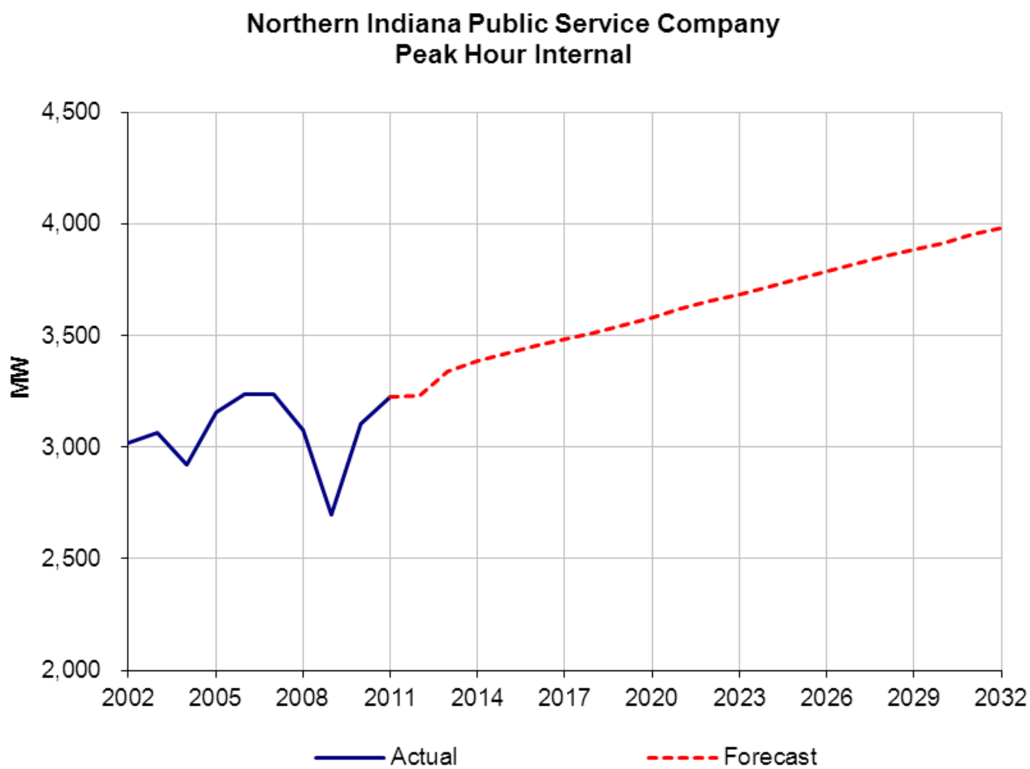
Energy and Demand Forecast (2011 - 2032)

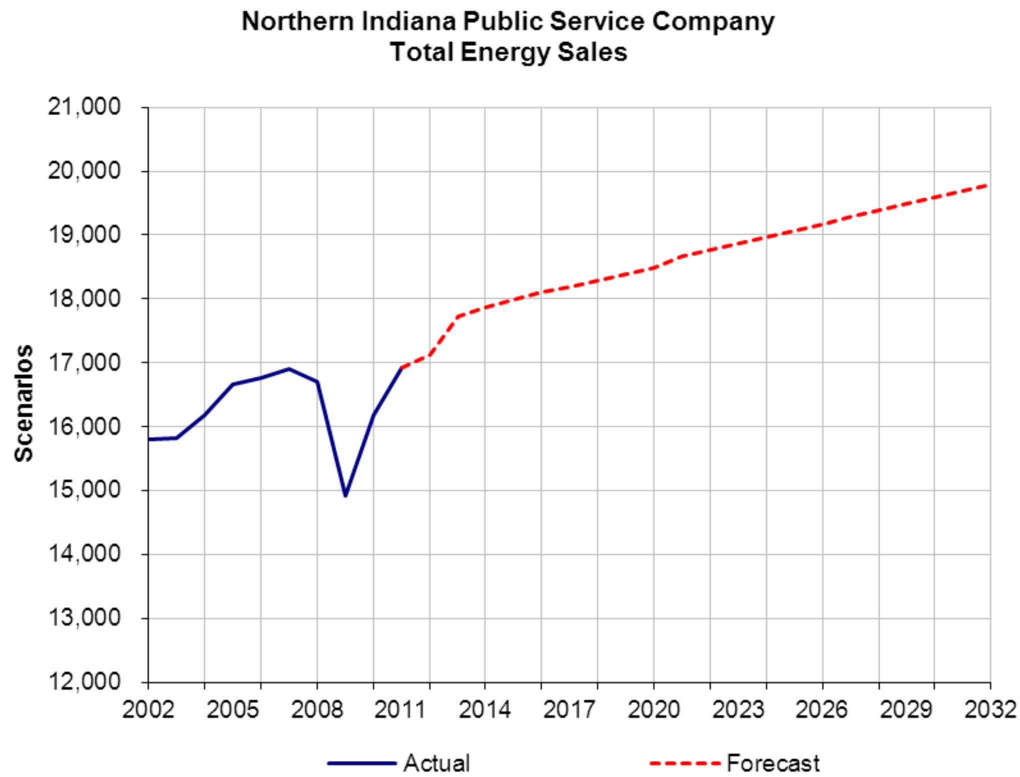
Summary:

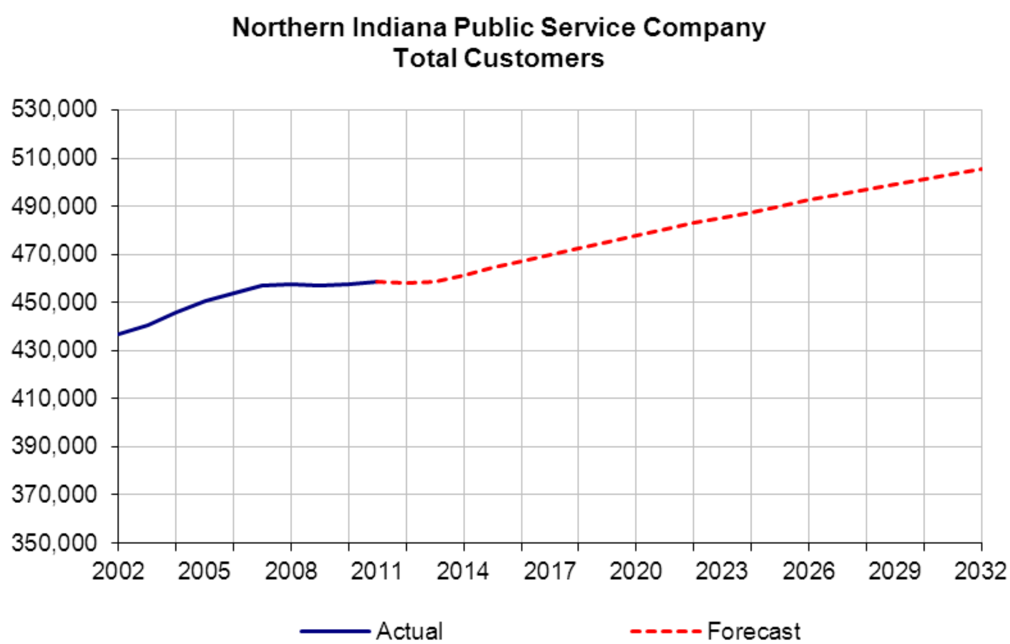
- NIPSCO Forecasts were produced by NiSource Corporate Services
- National, state and county forecasts were purchased from IHS Global Insight
- Compound Average Growth Rates for 21 years
  - Peak Hour 1.01%
  - Total Energy Sales 0.75%
  - Total Customers 0.47%

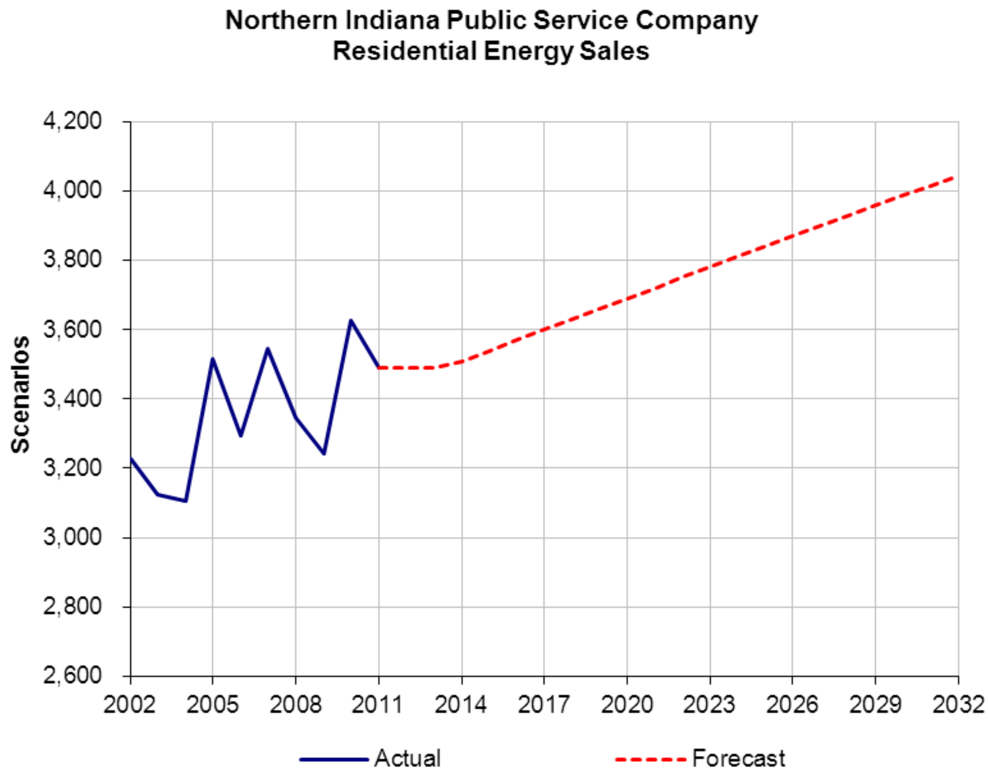
Method:

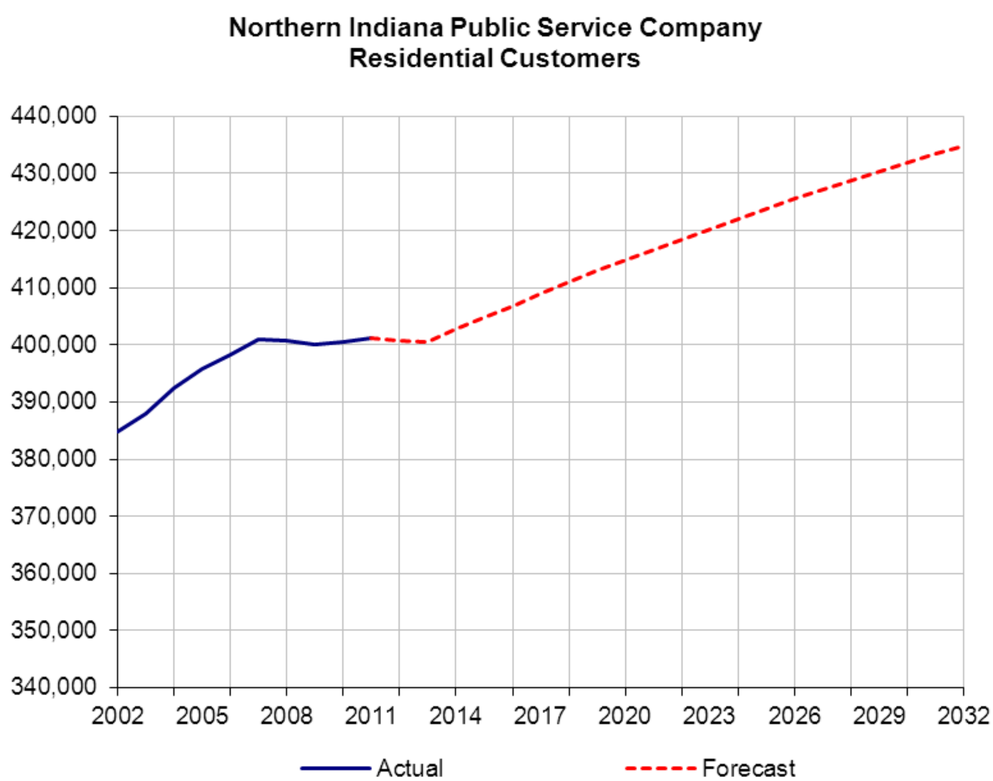
- The NIPSCO long-term forecast uses econometric models driven by national, state and local economic and energy consumption conditions. Energy forecasts are by class and demand is calculated with forecasted energy and average peak hour temperature and humidity.
- Residential energy consumption is driven by
  - Customer count, which is a function of a three year outlook for new construction provided by NIPSCO's new business team and a longer term outlook for construction driven by housing starts. Energy consumption per customer, which is a function of real price, real per capita income and appliance saturations and efficiencies.
  - Cooling and heating degree days
- Commercial energy consumption is driven by
  - A three year outlook for new construction provided by NIPSCO's new business team and a longer term outlook for construction modeled as a function of total employment
  - Energy consumption driven by customers, real price, and real gross county product.
  - Cooling and heating degree days
- Major Industrial energy consumption is driven by
  - A survey of major customers incorporated into a forecast model utilizing the Industrial Production Index (Primary Metals) growth curve.
- "Other" Industrial energy consumption is driven by
  - Industrial sales which are a function of national and state production indexes and the Industrial Production Index (Primary Metals).
- Street Lighting, Public Authority, Railroads, Company Use, and Losses
  - constants, percentages, and trends
- Demand Model is driven by
  - composition of load – i.e. residential, commercial and industrial
  - cooling degree hours (summer) or heating degree hours (winter) at peak hour
  - relative humidity at peak hour
- State and county level forecasts purchased from Global Insight

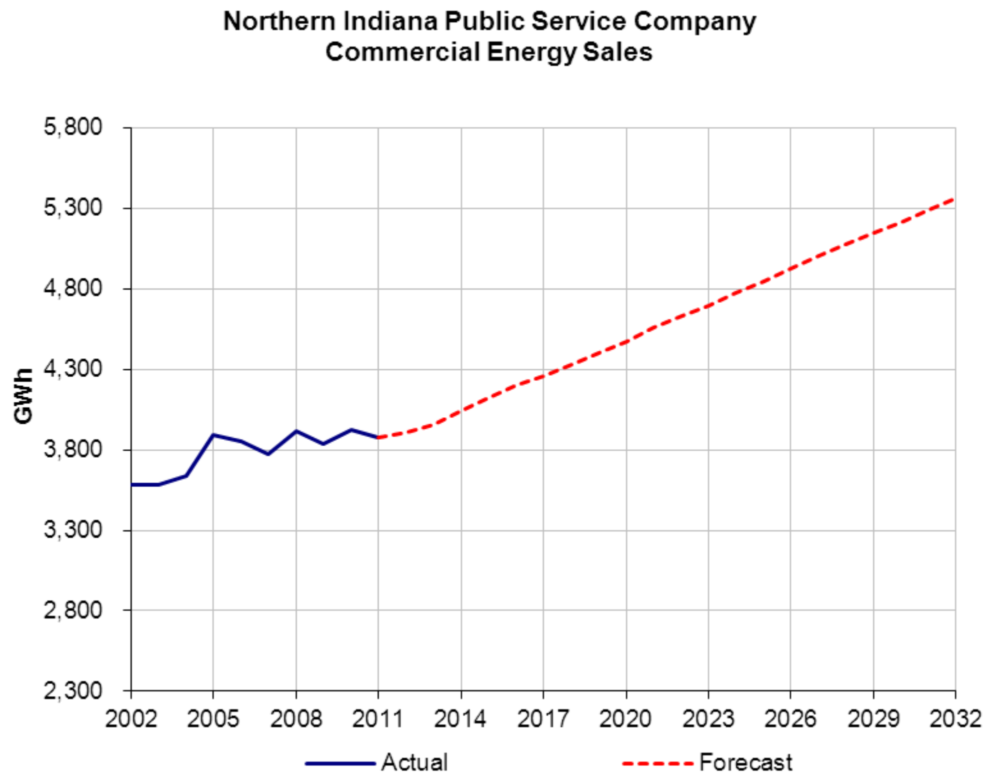

Northern Indiana Public Service Company
Peak Hour Internal
MW
4,500
4,000
3,500
3,000
2,500
2,000
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
2032
Actual
Forecast

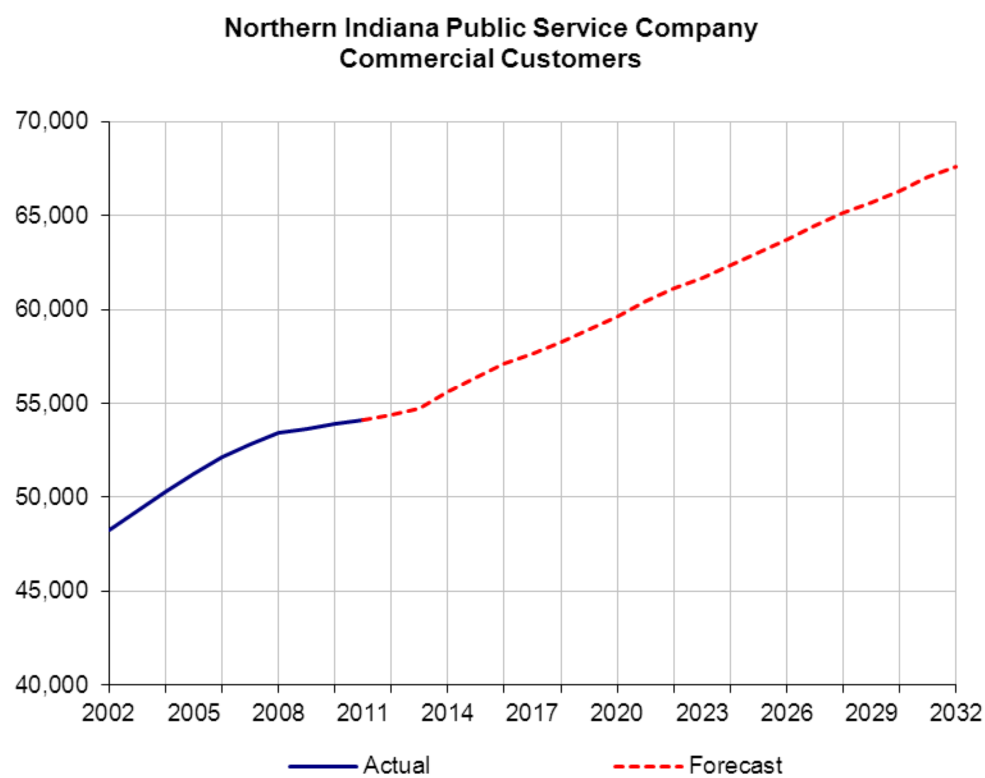

Northern Indiana Public Service Company
Total Energy Sales
Scenarios
21,000
20,000
19,000
18,000
17,000
16,000
15,000
14,000
13,000
12,000
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
2032
Actual
Forecast

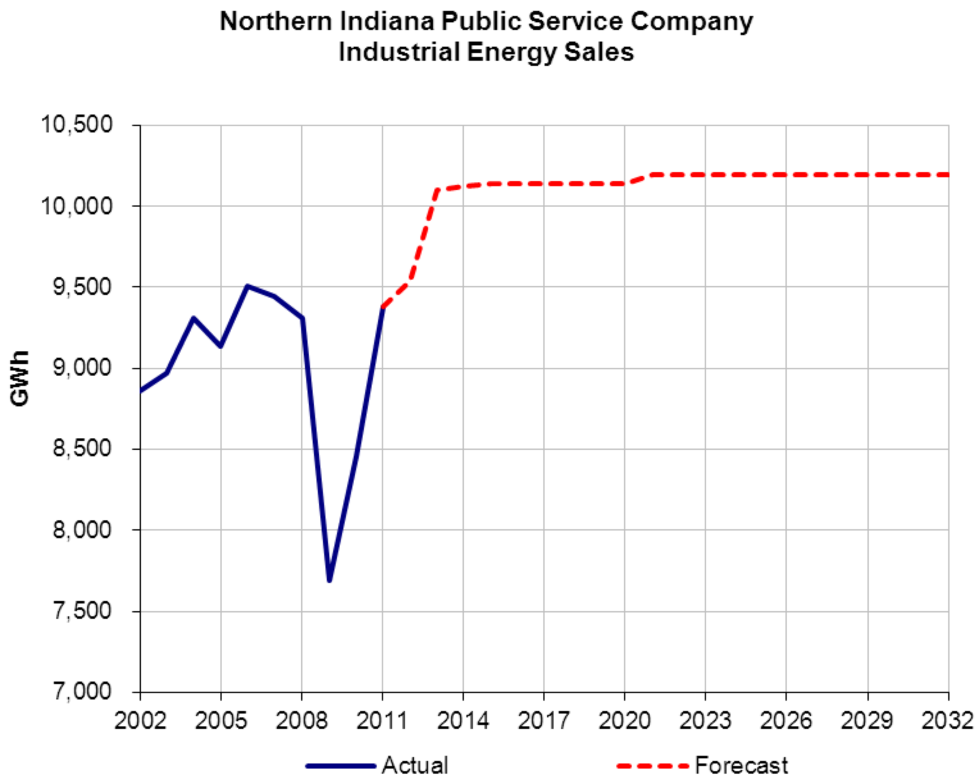

Northern Indiana Public Service Company
Total Customers
530,000
510,000
490,000
470,000
450,000
430,000
410,000
390,000
370,000
350,000
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
2032
Actual
Forecast


Northern Indiana Public Service Company
Residential Energy Sales
Scenarios
4,200
4,000
3,800
3,600
3,400
3,200
3,000
2,800
2,600
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
2032
Actual
Forecast


Northern Indiana Public Service Company
Residential Customers
440,000
430,000
420,000
410,000
400,000
390,000
380,000
370,000
360,000
350,000
340,000
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
2032
Actual
Forecast


Northern Indiana Public Service Company
Commercial Energy Sales
GWh
5,800
5,300
4,800
4,300
3,800
3,300
2,800
2,300
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
2032
Actual
Forecast


Northern Indiana Public Service Company
Commercial Customers
70,000
65,000
60,000
55,000
50,000
45,000
40,000
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
2032
Actual
Forecast


Northern Indiana Public Service Company
Industrial Energy Sales
GWh
10,500
10,000
9,500
9,000
8,500
8,000
7,500
7,000
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
2032
Actual
Forecast

2010 Hourly System Demand (Native Load)

2010 Hourly Native Load: The hourly demand for NIPSCO's native load is stated in MW, Hour Ending ("HE"), and Central Standard Time ("CST"). Native load includes losses, but does not include wholesale or off-system sales.

Date	HOUR ENDING											
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1/1/2010	1507	1481	1457	1440	1416	1424	1457	1452	1466	1491	1545	1566
1/1/2010	1603	1589	1560	1586	1601	1710	1771	1731	1750	1734	1694	1680
1/2/2010	1641	1586	1583	1579	1598	1597	1613	1638	1742	1767	1778	1767
1/2/2010	1790	1807	1800	1763	1791	1897	1993	1937	1906	1864	1876	1841
1/3/2010	1789	1746	1731	1699	1708	1720	1723	1709	1720	1744	1749	1762
1/3/2010	1758	1768	1783	1780	1801	1914	2017	1977	1955	1913	1891	1852
1/4/2010	1755	1737	1668	1704	1757	1801	1901	1900	1944	1966	1960	1958
1/4/2010	1934	1952	1971	1986	1944	2049	2071	2028	2000	1930	1904	1882
1/5/2010	1797	1761	1743	1739	1751	1821	1928	1993	1994	2011	2081	2108
1/5/2010	2080	2102	2079	2022	1980	2079	2131	2074	2051	1971	1926	1930
1/6/2010	1888	1816	1813	1806	1812	1846	1916	1953	1996	1999	1966	2022
1/6/2010	2006	1986	1956	1937	1962	2013	2078	2087	2070	2032	1969	1958
1/7/2010	1879	1850	1838	1825	1804	1870	1979	2064	2074	2102	2115	2085
1/7/2010	2077	2096	2037	2022	2015	2055	2135	2084	1989	1968	1950	1937
1/8/2010	1867	1833	1836	1825	1782	1832	1934	1938	2001	1979	1984	1990
1/8/2010	1971	1938	1934	1920	1921	1990	2016	1936	1899	1878	1851	1835
1/9/2010	1747	1732	1707	1679	1648	1638	1708	1719	1750	1780	1788	1819
1/9/2010	1790	1795	1743	1719	1732	1797	1884	1804	1810	1808	1821	1749
1/10/2010	1642	1616	1603	1572	1579	1587	1604	1631	1708	1769	1796	1779
1/10/2010	1792	1792	1767	1745	1780	1871	1981	1938	1901	1910	1899	1825
1/11/2010	1735	1696	1655	1679	1684	1758	1853	1934	1966	1991	2016	1998
1/11/2010	1967	1962	1970	1970	1980	2036	2079	2027	2002	1964	1902	1869
1/12/2010	1773	1741	1701	1703	1733	1816	1930	1988	2015	2024	2028	2022
1/12/2010	2018	2016	1973	1975	1962	2009	2041	2008	1992	1988	1939	1909
1/13/2010	1856	1829	1769	1761	1799	1842	1933	2011	1985	2013	2022	1998
1/13/2010	1971	1970	1970	1941	1939	1974	2093	2044	2019	1971	1933	1862
1/14/2010	1778	1775	1745	1723	1757	1788	1920	1966	1971	1960	1966	1997
1/14/2010	2008	1975	2024	1945	1992	2037	2134	2110	2040	2030	2003	1950
1/15/2010	1889	1878	1831	1812	1776	1887	2014	2055	2078	2111	2129	2100
1/15/2010	2073	2088	2029	1994	1977	2017	2077	2023	2017	1987	1935	1895
1/16/2010	1803	1752	1715	1696	1705	1755	1781	1806	1796	1851	1837	1867
1/16/2010	1864	1852	1838	1786	1757	1850	1930	1863	1872	1826	1825	1742
1/17/2010	1681	1640	1621	1603	1633	1656	1615	1629	1680	1688	1696	1730
1/17/2010	1700	1680	1644	1662	1696	1733	1847	1805	1830	1820	1814	1742
1/18/2010	1664	1612	1591	1596	1587	1655	1749	1816	1867	1914	1895	1926
1/18/2010	1874	1864	1835	1860	1853	1854	1908	1875	1871	1827	1776	1750
1/19/2010	1672	1647	1619	1622	1623	1699	1811	1872	1946	1953	1964	1987
1/19/2010	1970	1984	1928	1881	1851	1875	1971	1942	1888	1863	1844	1800
1/20/2010	1722	1678	1675	1648	1664	1697	1812	1889	1972	1974	2010	2032
1/20/2010	2058	2041	2015	2001	1971	1986	2101	2020	1976	1946	1910	1903
1/21/2010	1814	1814	1791	1755	1757	1829	1924	2016	2034	2038	2030	2016
1/21/2010	2036	2033	2024	1992	1978	2082	2087	2035	1996	1937	1913	1851
1/22/2010	1762	1741	1722	1763	1775	1824	1956	2012	2042	2022	2078	2001
1/22/2010	2054	2049	1996	1989	1873	1943	1992	1910	1926	1906	1860	1881
1/23/2010	1750	1679	1700	1635	1685	1696	1710	1737	1752	1756	1779	1828
1/23/2010	1793	1792	1776	1793	1787	1849	1902	1854	1778	1726	1752	1664
1/24/2010	1596	1581	1530	1581	1576	1540	1581	1586	1618	1617	1656	1667
1/24/2010	1656	1654	1638	1650	1690	1720	1794	1764	1790	1753	1781	1719
1/25/2010	1680	1624	1620	1599	1637	1697	1802	1891	1890	1875	1894	1911
1/25/2010	1919	1936	1897	1893	1888	1928	1982	1963	1963	1919	1897	1883
1/26/2010	1844	1824	1779	1726	1741	1756	1860	1971	2000	2041	2044	2095
1/26/2010	2105	2042	2028	2015	2012	2025	2068	2058	2053	2019	1996	2003
1/27/2010	1905	1866	1828	1832	1882	1973	2085	2135	2133	2149	2150	2145
1/27/2010	2145	2161	2121	2082	2049	2098	2139	2136	2092	2100	2037	2001
1/28/2010	1896	1892	1899	1887	1905	1991	2126	2194	2249	2236	2181	2189
1/28/2010	2211	2181	2122	2099	2064	2087	2200	2154	2145	2097	2084	2051
1/29/2010	1994	1962	1938	1955	1964	1978	2102	2165	2127	2127	2134	2111
1/29/2010	2081	2078	2006	1980	2002	1999	2052	2035	2007	1992	1965	1942
1/30/2010	1886	1861	1832	1782	1758	1766	1814	1841	1864	1903	1906	1870
1/30/2010	1836	1845	1814	1805	1775	1824	1940	1925	1904	1868	1879	1835
1/31/2010	1776	1781	1750	1711	1716	1752	1748	1744	1751	1762	1673	1767
1/31/2010	1777	1784	1752	1734	1743	1764	1893	1898	1870	1846	1853	1828

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
2/1/2010	1747	1684	1690	1669	1697	1777	1854	1941	1956	1959	1933	1926
2/1/2010	1916	1874	1849	1808	1847	1874	1960	1966	1922	1847	1799	1758
2/2/2010	1693	1638	1613	1627	1642	1698	1760	1822	1887	1996	2020	2007
2/2/2010	1995	1995	1939	1858	1817	1815	1912	1875	1847	1842	1797	1776
2/3/2010	1694	1691	1707	1717	1735	1780	1899	1992	2017	2039	2036	2061
2/3/2010	2045	1994	1988	1970	1939	1981	2053	2035	1973	1944	1905	1849
2/4/2010	1759	1684	1669	1711	1763	1813	1927	2019	2030	2031	2035	2014
2/4/2010	2025	1998	1985	1959	1950	1943	2041	2047	2029	1978	1977	1979
2/5/2010	1874	1836	1773	1790	1828	1909	1984	2037	2055	2068	2054	2106
2/5/2010	2078	2057	2023	1990	2012	2033	2048	1987	1983	1975	1949	1925
2/6/2010	1814	1751	1794	1749	1737	1777	1842	1825	1826	1870	1911	1883
2/6/2010	1846	1841	1766	1740	1741	1807	1882	1843	1849	1813	1784	1712
2/7/2010	1674	1675	1662	1617	1593	1557	1589	1584	1561	1565	1571	1561
2/7/2010	1558	1557	1572	1585	1625	1640	1733	1738	1733	1702	1742	1683
2/8/2010	1628	1607	1638	1671	1726	1760	1884	1944	1965	1925	1923	1922
2/8/2010	1903	1876	1846	1799	1824	1858	1923	1940	1924	1863	1813	1823
2/9/2010	1765	1739	1714	1737	1720	1793	1896	1951	1968	1990	2027	2065
2/9/2010	2037	1961	1940	1900	1874	1890	1949	1971	1969	1928	1886	1888
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2/11/2010	1853	1826	1817	1827	1860	1902	1995	2056	2087	2079	2099	2120
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2/12/2010	1977	1934	1925	1919	1947	2004	2049	2097	2152	2107	2144	2099
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2/19/2010	1793	1762	1783	1750	1793	1820	1940	1958	1981	2018	2046	1998
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2/21/2010	1656	1606	1585	1594	1651	1673	1783	1755	1781	1742	1759	1686
2/22/2010	1625	1622	1638	1598	1648	1607	1676	1733	1773	1793	1819	1852
2/22/2010	1880	1869	1846	1812	1783	1824	1894	1885	1862	1801	1736	1712
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3/4/2010	1824	1797	1729	1758	1785	1849	1976	1984	2013	2036	2040	2011
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3/6/2010	1788	1755	1688	1687	1680	1752	1769	1707	1707	1735	1746	1741
3/6/2010	1718	1710	1712	1653	1616	1626	1665	1741	1757	1725	1717	1685
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3/7/2010	1609	1616	1635	1598	1572	1594	1682	1734	1682	1688	1746	1643
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3/8/2010	1854	1811	1799	1786	1715	1713	1733	1779	1768	1766	1723	1694
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3/9/2010	1815	1916	1836	1866	1892	1832	1830	1896	1869	1820	1744	1727
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3/11/2010	1681	1624	1612	1610	1618	1672	1779	1833	1918	2005	2037	2032
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3/18/2010	1666	1648	1625	1636	1749	1825	1943	1962	1973	1966	1974	1953
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3/19/2010	1686	1670	1651	1663	1735	1856	1901	1902	1919	1968	1984	1933
3/19/2010	1899	1891	1833	1852	1825	1746	1768	1816	1782	1725	1680	1645
3/20/2010	1641	1631	1536	1552	1564	1614	1730	1744	1757	1777	1798	1823
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3/21/2010	1637	1591	1567	1547	1577	1617	1642	1613	1612	1675	1651	1653
3/21/2010	1655	1674	1625	1583	1606	1665	1676	1681	1644	1616	1643	1601
3/22/2010	1571	1556	1562	1576	1632	1725	1832	1865	1886	1958	1934	1936
3/22/2010	1933	1907	1798	1775	1770	1708	1725	1774	1782	1788	1715	1696
3/23/2010	1674	1636	1619	1642	1669	1751	1833	1872	1841	1862	1852	1798
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3/24/2010	1593	1585	1578	1573	1644	1697	1822	1900	1938	1961	1990	2007
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3/25/2010	1926	1929	1863	1833	1827	1835	1871	1907	1909	1852	1795	1754
3/26/2010	1752	1742	1701	1724	1752	1844	1980	1934	1996	1971	1953	1948
3/26/2010	1938	1928	1897	1813	1814	1801	1797	1859	1854	1802	1731	1696
3/27/2010	1650	1635	1616	1623	1619	1698	1753	1743	1772	1763	1742	1746
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3/28/2010	1531	1500	1494	1477	1463	1534	1554	1589	1642	1662	1680	1696
3/28/2010	1728	1664	1683	1737	1726	1719	1726	1733	1754	1715	1704	1688
3/29/2010	1632	1636	1652	1650	1709	1840	1949	1996	1960	1991	1960	1894
3/29/2010	1868	1865	1854	1795	1737	1765	1776	1824	1880	1791	1741	1743
3/30/2010	1692	1612	1589	1686	1774	1854	1983	1947	2000	1992	1980	1919
3/30/2010	1923	1907	1871	1831	1795	1824	1824	1873	1866	1803	1677	1665
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4/2/2010	1658	1675	1665	1638	1633	1593	1579	1586	1597	1551	1481	1472
4/3/2010	1472	1440	1421	1393	1378	1418	1419	1424	1438	1485	1508	1552
4/3/2010	1571	1550	1553	1519	1543	1528	1482	1548	1584	1551	1478	1443
4/4/2010	1440	1414	1332	1359	1358	1415	1409	1399	1431	1448	1435	1425
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4/5/2010	1449	1444	1455	1457	1528	1641	1727	1728	1734	1827	1868	1832
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4/6/2010	1535	1538	1544	1552	1629	1722	1813	1853	1902	1908	1919	1908
4/6/2010	1938	1892	1869	1879	1861	1904	1797	1837	1862	1824	1737	1701
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4/7/2010	1968	1978	1947	1945	1910	1904	1906	1904	1954	1883	1799	1808
4/8/2010	1775	1702	1710	1728	1824	1934	1991	2054	2108	2126	2115	2116
4/8/2010	2126	2136	2097	2013	2053	1997	1946	1899	1948	1897	1840	1804
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4/10/2010	1637	1625	1624	1594	1596	1601	1650	1641	1684	1722	1664	1612
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4/11/2010	1545	1501	1498	1494	1522	1541	1553	1584	1614	1623	1636	1634
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4/15/2010	1692	1635	1633	1620	1642	1747	1797	1859	1847	1886	1908	1979
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4/16/2010	1649	1642	1621	1619	1638	1728	1846	1902	1956	1956	1941	1926
4/16/2010	1885	1888	1809	1796	1721	1707	1689	1663	1689	1628	1605	1573
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4/17/2010	1632	1526	1540	1545	1531	1520	1535	1532	1546	1546	1515	1442
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4/18/2010	1424	1423	1456	1463	1495	1479	1458	1479	1515	1496	1534	1485
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5/9/2010	1532	1493	1467	1454	1475	1466	1468	1442	1498	1507	1495	1467
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5/15/2010	1617	1608	1599	1574	1649	1648	1651	1637	1685	1643	1584	1517
5/16/2010	1448	1398	1396	1433	1427	1389	1419	1432	1461	1558	1575	1588
5/16/2010	1585	1578	1602	1544	1551	1567	1586	1510	1552	1547	1566	1531
5/17/2010	1504	1473	1412	1457	1578	1641	1740	1763	1789	1845	1840	1857
5/17/2010	1875	1820	1840	1769	1805	1778	1799	1774	1819	1770	1697	1670
5/18/2010	1645	1598	1605	1579	1611	1725	1789	1777	1788	1836	1853	1851
5/18/2010	1855	1841	1849	1849	1795	1822	1753	1762	1790	1706	1654	1650
5/19/2010	1626	1591	1567	1554	1606	1649	1753	1782	1825	1874	1883	1871
5/19/2010	1855	1887	1889	1828	1791	1794	1772	1772	1865	1854	1780	1714
5/20/2010	1671	1639	1629	1696	1711	1761	1838	1844	1982	2002	2051	2040
5/20/2010	2037	2066	2007	1937	1988	1911	1924	1935	1982	1911	1790	1704
5/21/2010	1707	1673	1662	1662	1736	1854	1910	1919	1872	1926	1952	2035
5/21/2010	1978	1959	1950	1897	1885	1897	1866	1795	1820	1796	1764	1720
5/22/2010	1646	1629	1608	1589	1588	1619	1643	1705	1768	1815	1748	1779
5/22/2010	1783	1783	1743	1736	1768	1769	1763	1668	1733	1752	1675	1608
5/23/2010	1551	1469	1450	1441	1455	1415	1445	1418	1516	1606	1714	1805
5/23/2010	1857	1927	1952	1999	2000	2029	2052	1988	2032	2035	1955	1856
5/24/2010	1757	1706	1649	1684	1685	1759	1846	1968	2111	2221	2320	2436
5/24/2010	2501	2535	2532	2539	2564	2561	2489	2399	2394	2297	2178	2061
5/25/2010	1975	1874	1825	1799	1879	1867	2010	2110	2185	2328	2449	2528
5/25/2010	2546	2594	2622	2634	2626	2597	2518	2422	2392	2275	2044	2002
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5/26/2010	2572	2674	2695	2703	2681	2589	2528	2367	2327	2177	2093	1960
5/27/2010	1906	1827	1791	1806	1869	1904	2042	2117	2180	2226	2306	2313
5/27/2010	2350	2356	2312	2247	2191	2199	2137	2054	2005	1949	1842	1800
5/28/2010	1738	1703	1664	1633	1630	1628	1793	1893	1932	2043	2083	2108
5/28/2010	2173	2153	2175	2094	2149	2087	2057	1930	1926	1883	1795	1733
5/29/2010	1674	1616	1612	1606	1592	1560	1544	1642	1724	1862	1983	2033
5/29/2010	2090	2129	2165	2183	2113	2129	2115	2028	1985	1912	1806	1709
5/30/2010	1632	1534	1474	1450	1458	1419	1431	1527	1634	1780	1826	1906
5/30/2010	1995	2097	2173	2207	2219	2177	2157	2036	2046	1982	1887	1804
5/31/2010	1631	1616	1563	1550	1529	1544	1536	1575	1683	1769	1916	2019
5/31/2010	1935	1866	1797	1772	1786	1755	1782	1745	1787	1754	1695	1651

Date	HOUR ENDING											
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6/1/2010	2171	2272	2295	2303	2368	2348	2287	2216	2238	2167	1997	1887
6/2/2010	1814	1754	1732	1715	1794	1878	1945	2024	2063	2166	2230	2255
6/2/2010	2263	2282	2209	2191	2230	2164	2176	2067	2074	1989	1834	1706
6/3/2010	1657	1647	1620	1628	1708	1751	1819	1866	2003	2066	2089	2069
6/3/2010	2121	2162	2109	2090	2087	2064	2010	1921	1921	1932	1833	1785
6/4/2010	1718	1663	1649	1636	1645	1710	1798	1932	1982	2057	2112	2176
6/4/2010	2205	2188	2200	2133	2075	2115	2096	2027	2015	1960	1856	1828
6/5/2010	1747	1693	1659	1613	1646	1638	1669	1753	1823	1900	1960	1976
6/5/2010	1958	1990	2034	1973	1989	2020	1966	1926	1979	1870	1869	1719
6/6/2010	1605	1539	1500	1471	1461	1426	1427	1472	1597	1663	1709	1716
6/6/2010	1772	1790	1737	1685	1710	1661	1681	1630	1631	1636	1604	1539
6/7/2010	1473	1439	1438	1448	1533	1540	1644	1717	1885	1940	1984	2032
6/7/2010	2034	1994	1945	1959	1926	1925	1851	1841	1835	1810	1711	1688
6/8/2010	1635	1619	1585	1600	1639	1702	1824	1853	1873	1913	1928	1917
6/8/2010	1942	1885	1947	1913	1884	1855	1877	1850	1837	1765	1709	1675
6/9/2010	1591	1575	1592	1640	1684	1809	1882	1958	2045	2059	2097	2204
6/9/2010	2221	2216	2259	2271	2282	2304	2261	2139	2021	1970	1869	1799
6/10/2010	1691	1660	1605	1623	1667	1725	1802	1898	2016	2081	2117	2192
6/10/2010	2207	2221	2244	2267	2320	2245	2185	2050	2070	2055	1987	1995
6/11/2010	1889	1816	1765	1752	1873	1922	1935	2013	2180	2377	2450	2558
6/11/2010	2701	2731	2703	2692	2667	2617	2609	2484	2378	2361	2242	2097
6/12/2010	1993	1959	1894	1858	1871	1865	1886	1961	2045	2103	2210	2150
6/12/2010	2134	2205	2268	2284	2208	2153	2108	1986	1956	1947	1833	1714
6/13/2010	1643	1618	1589	1571	1557	1556	1549	1579	1623	1676	1686	1754
6/13/2010	1771	1812	1787	1804	1747	1776	1789	1706	1777	1846	1827	1745
6/14/2010	1676	1662	1647	1655	1702	1795	1867	1899	2026	2093	2112	2166
6/14/2010	2214	2236	2245	2211	2167	2102	2071	2003	1940	1963	1886	1836
6/15/2010	1815	1690	1720	1738	1826	1902	1982	2044	2076	2134	2167	2234
6/15/2010	2263	2308	2309	2343	2389	2423	2342	2280	2143	2188	2072	1983
6/16/2010	1861	1747	1735	1691	1750	1799	1889	2000	2082	2177	2234	2290
6/16/2010	2318	2297	2337	2344	2302	2312	2251	2180	2191	2151	2065	1974
6/17/2010	1877	1797	1821	1817	1871	1877	2026	2113	2188	2301	2327	2429
6/17/2010	2476	2611	2605	2576	2587	2536	2508	2401	2349	2348	2216	2127
6/18/2010	2026	1920	1914	1876	1908	1935	1968	1756	2028	2273	2463	2652
6/18/2010	2722	2807	2851	2869	2768	2410	2195	2048	2010	2005	1924	1850
6/19/2010	1798	1775	1758	1742	1712	1697	1753	1775	1951	2039	2095	2161
6/19/2010	2203	2282	2334	2351	2375	2366	2375	2205	2157	2021	1949	1820
6/20/2010	1697	1637	1625	1590	1563	1546	1557	1652	1752	1813	1909	1979
6/20/2010	2008	2049	2046	2052	2076	2113	2065	1968	1980	1912	1877	1800
6/21/2010	1709	1683	1639	1647	1708	1756	1892	1972	2039	2144	2119	2169
6/21/2010	2216	2291	2337	2402	2446	2408	2473	2387	2380	2319	2167	2083
6/22/2010	1952	1891	1905	1894	1881	1956	2045	2110	2218	2327	2455	2576
6/22/2010	2599	2649	2667	2645	2631	2582	2573	2443	2367	2315	2202	2125
6/23/2010	2037	1968	1953	1989	1979	2008	2110	2228	2298	2294	2314	2324
6/23/2010	2328	2401	2469	2604	2683	2691	2568	2393	2188	2068	1966	1928
6/24/2010	1838	1818	1775	1749	1852	1897	1971	2006	2088	2174	2221	2303
6/24/2010	2380	2383	2432	2403	2420	2402	2315	2196	2164	2175	2108	2019
6/25/2010	1937	1876	1847	1800	1820	1804	1891	1950	2087	2243	2292	2368
6/25/2010	2443	2456	2466	2458	2505	2450	2453	2321	2308	2301	2105	2049
6/26/2010	1941	1841	1860	1802	1804	1831	1870	1866	1970	2071	2218	2305
6/26/2010	2417	2525	2548	2536	2466	2538	2486	2317	2249	2207	2128	1928
6/27/2010	1847	1810	1744	1750	1724	1683	1677	1768	2005	2138	2173	2133
6/27/2010	2196	2277	2323	2385	2372	2380	2337	2250	2211	2177	2124	1999
6/28/2010	1880	1814	1790	1769	1825	1867	1956	2038	2198	2295	2374	2433
6/28/2010	2494	2492	2439	2442	2400	2386	2308	2190	2190	2081	2024	1903
6/29/2010	1813	1742	1713	1709	1758	1793	1845	1953	2050	2129	2214	2230
6/29/2010	2214	2157	2174	2128	2181	2057	2030	1930	1902	1927	1840	1723
6/30/2010	1676	1613	1558	1579	1638	1642	1705	1787	1861	1912	1941	1968
6/30/2010	2091	2100	2150	2076	2113	2028	1996	1861	1931	1893	1806	1756

Date	HOUR ENDING											
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7/1/2010	2002	2018	2011	2033	2047	2040	1988	1917	1904	1924	1838	1834
7/2/2010	1736	1688	1639	1680	1705	1704	1770	1817	1887	2020	2082	2095
7/2/2010	2187	2169	2204	2203	2223	2218	2197	2105	2055	2069	1924	1792
7/3/2010	1715	1640	1611	1588	1598	1566	1571	1614	1723	1865	1938	2008
7/3/2010	2059	2082	2136	2145	2157	2184	2148	2051	1958	1892	1873	1768
7/4/2010	1666	1571	1541	1483	1458	1402	1458	1534	1678	1852	2009	2159
7/4/2010	2292	2335	2358	2348	2348	2314	2248	2182	2144	2096	2068	1984
7/5/2010	1899	1817	1760	1732	1705	1691	1727	1836	1948	2139	2287	2389
7/5/2010	2434	2457	2510	2483	2496	2469	2415	2290	2262	2225	2062	1952
7/6/2010	1826	1744	1705	1741	1756	1827	1927	2088	2205	2306	2394	2540
7/6/2010	2689	2662	2782	2828	2794	2756	2715	2638	2597	2550	2384	2256
7/7/2010	2151	2009	2005	1965	1988	2004	2113	2233	2459	2573	2671	2841
7/7/2010	2796	2834	2901	2890	2861	2793	2676	2626	2573	2472	2347	2278
7/8/2010	2179	2093	1984	1854	1944	2036	2079	2149	2263	2317	2426	2469
7/8/2010	2530	2616	2615	2576	2615	2654	2616	2429	2432	2375	2320	2279
7/9/2010	2152	2050	1973	2012	2063	2101	2174	2209	2272	2355	2518	2608
7/9/2010	2656	2764	2764	2720	2682	2649	2615	2440	2357	2277	2162	2049
7/10/2010	1939	1940	1866	1825	1801	1749	1811	1899	2047	2138	2235	2292
7/10/2010	2377	2491	2525	2478	2423	2383	2304	2220	2193	2135	2023	1905
7/11/2010	1806	1735	1688	1608	1631	1612	1601	1681	1828	1957	2101	2173
7/11/2010	2238	2290	2290	2313	2338	2263	2205	2086	2100	2136	2129	1998
7/12/2010	1926	1823	1767	1821	1851	1893	1969	2078	2187	2289	2398	2463
7/12/2010	2497	2540	2528	2509	2488	2441	2394	2311	2288	2243	2099	1973
7/13/2010	1867	1788	1749	1736	1768	1820	1928	1980	2045	2074	2185	2271
7/13/2010	2365	2416	2451	2448	2527	2500	2441	2317	2313	2280	2132	1958
7/14/2010	1836	1774	1753	1741	1830	1850	1936	2102	2206	2412	2584	2677
7/14/2010	2768	2784	2772	2797	2794	2757	2717	2582	2547	2473	2310	2196
7/15/2010	2127	2024	1933	1907	1951	2005	2094	2208	2355	2473	2571	2718
7/15/2010	2803	2878	2895	2852	2852	2770	2682	2584	2589	2556	2401	2257
7/16/2010	2146	2046	1982	1958	1999	2059	2102	2226	2351	2457	2564	2661
7/16/2010	2740	2750	2764	2791	2798	2769	2698	2609	2564	2527	2355	2234
7/17/2010	2096	2013	1968	1949	1925	1883	1890	1993	2161	2325	2444	2546
7/17/2010	2655	2715	2759	2743	2709	2723	2642	2513	2465	2393	2284	2067
7/18/2010	1929	1850	1786	1748	1721	1692	1687	1783	1828	1993	2179	2260
7/18/2010	2303	2220	2239	2321	2409	2454	2423	2351	2295	2190	2126	2006
7/19/2010	1940	1882	1872	1859	1914	1953	2043	2151	2297	2442	2520	2612
7/19/2010	2646	2578	2616	2586	2559	2495	2444	2356	2336	2260	2132	2043
7/20/2010	1964	1885	1843	1807	1882	1967	2043	2098	2211	2303	2345	2342
7/20/2010	2425	2439	2457	2528	2579	2583	2591	2461	2442	2421	2275	2193
7/21/2010	2112	2052	2005	1962	2012	2058	2137	2216	2417	2489	2613	2759
7/21/2010	2812	2889	2879	2892	2854	2810	2776	2646	2607	2594	2446	2317
7/22/2010	2172	2028	1963	1941	2030	2033	2110	2206	2312	2390	2464	2551
7/22/2010	2597	2618	2642	2633	2619	2646	2654	2594	2657	2583	2493	2423
7/23/2010	2334	2293	2221	2250	2264	2277	2318	2480	2609	2712	2870	2964
7/23/2010	3017	3036	3031	2966	2960	2894	2845	2719	2654	2580	2338	2201
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7/24/2010	2444	2520	2614	2687	2713	2646	2546	2426	2374	2304	2237	2071
7/25/2010	1986	1880	1851	1784	1793	1777	1795	1833	1912	2073	2123	2130
7/25/2010	2168	2215	2222	2230	2214	2214	2187	2105	2037	1981	1958	1868
7/26/2010	1775	1734	1696	1684	1737	1810	1890	1990	2109	2217	2332	2433
7/26/2010	2429	2530	2514	2531	2510	2524	2419	2291	2293	2258	2132	1994
7/27/2010	1953	1891	1874	1880	1953	2026	2034	2131	2233	2233	2635	2739
7/27/2010	2851	2761	2640	2661	2709	2651	2603	2442	2424	2328	2197	2164
7/28/2010	2126	2085	2077	2077	2171	2175	2181	2303	2366	2511	2651	2838
7/28/2010	2901	2919	2959	2823	2630	2585	2521	2449	2446	2411	2295	2162
7/29/2010	2149	2074	1943	1970	1976	2004	2045	2053	2181	2293	2402	2479
7/29/2010	2520	2527	2518	2532	2473	2408	2312	2209	2249	2218	2096	2002
7/30/2010	1910	1883	1809	1828	1840	1952	1920	1947	2035	2194	2217	2320
7/30/2010	2354	2396	2402	2349	2283	2256	2209	2162	2172	2126	2036	1957
7/31/2010	1858	1816	1811	1778	1767	1815	1806	1795	1850	1912	1960	1966
7/31/2010	2011	2007	2020	1986	1978	1994	1988	1838	1933	1888	1788	1682

Date	HOUR ENDING											
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8/2/2010	1730	1661	1653	1655	1719	1794	1875	1959	2084	2217	2353	2482
8/2/2010	2504	2493	2614	2572	2544	2481	2430	2330	2298	2238	2174	2093
8/3/2010	2050	1915	1847	1850	1935	2018	2112	2173	2206	2261	2313	2398
8/3/2010	2484	2586	2660	2657	2715	2697	2669	2614	2669	2498	2359	2292
8/4/2010	2201	2136	2105	2101	2103	2192	2258	2358	2399	2454	2393	2404
8/4/2010	2522	2507	2547	2568	2550	2487	2450	2390	2376	2284	2161	2043
8/5/2010	1972	2000	1919	1980	1979	2055	2111	2192	2374	2462	2554	2647
8/5/2010	2716	2717	2700	2681	2655	2628	2521	2381	2309	2246	2092	2004
8/6/2010	1904	1895	1852	1857	1861	1929	1928	2017	2147	2226	2344	2417
8/6/2010	2437	2462	2414	2433	2433	2396	2353	2246	2265	2204	2078	2014
8/7/2010	1922	1792	1739	1704	1699	1701	1685	1798	1962	2052	2151	2175
8/7/2010	2187	2276	2334	2396	2397	2422	2394	2281	2223	2141	2095	1945
8/8/2010	1859	1801	1735	1705	1659	1633	1609	1698	1778	1852	1906	1889
8/8/2010	1908	1981	2032	2153	2283	2321	2298	2211	2252	2190	2083	1988
8/9/2010	1885	1851	1811	1817	1909	1974	2049	2107	2254	2338	2422	2478
8/9/2010	2610	2642	2684	2740	2683	2698	2616	2485	2462	2406	2268	2180
8/10/2010	2060	1990	1916	1932	1974	2032	2143	2220	2350	2466	2604	2668
8/10/2010	2771	2870	2918	2921	2965	2916	2882	2752	2724	2601	2462	2383
8/11/2010	2256	2218	2173	2087	2115	2170	2231	2277	2483	2561	2682	2770
8/11/2010	2866	2948	2946	2907	2941	2908	2847	2691	2676	2581	2368	2250
8/12/2010	2189	2081	2029	2023	2080	2110	2157	2259	2410	2553	2679	2792
8/12/2010	2866	2892	2893	2876	2894	2877	2774	2673	2631	2533	2396	2274
8/13/2010	2192	2067	2035	1986	2030	2108	2133	2223	2383	2502	2658	2750
8/13/2010	2834	2818	2854	2802	2841	2761	2685	2590	2614	2530	2362	2246
8/14/2010	2150	2052	1990	1946	1941	1930	1931	1968	2009	2059	2097	2135
8/14/2010	2252	2346	2396	2432	2444	2494	2423	2277	2281	2223	2115	1955
8/15/2010	1848	1792	1751	1693	1723	1752	1739	1787	1914	2083	2225	2297
8/15/2010	2341	2377	2393	2433	2423	2413	2346	2194	2192	2095	2008	1891
8/16/2010	1801	1768	1707	1676	1744	1858	1905	1945	2037	2151	2218	2270
8/16/2010	2322	2337	2379	2402	2373	2319	2274	2142	2089	2063	1931	1847
8/17/2010	1725	1669	1671	1666	1753	1790	1800	1900	2067	2106	2261	2364
8/17/2010	2371	2405	2424	2399	2329	2266	2212	2200	2261	2199	2047	1957
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Date	HOUR ENDING											
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9/15/2010	2153	2124	2131	2066	2083	2051	2022	2072	2056	1949	1889	1857
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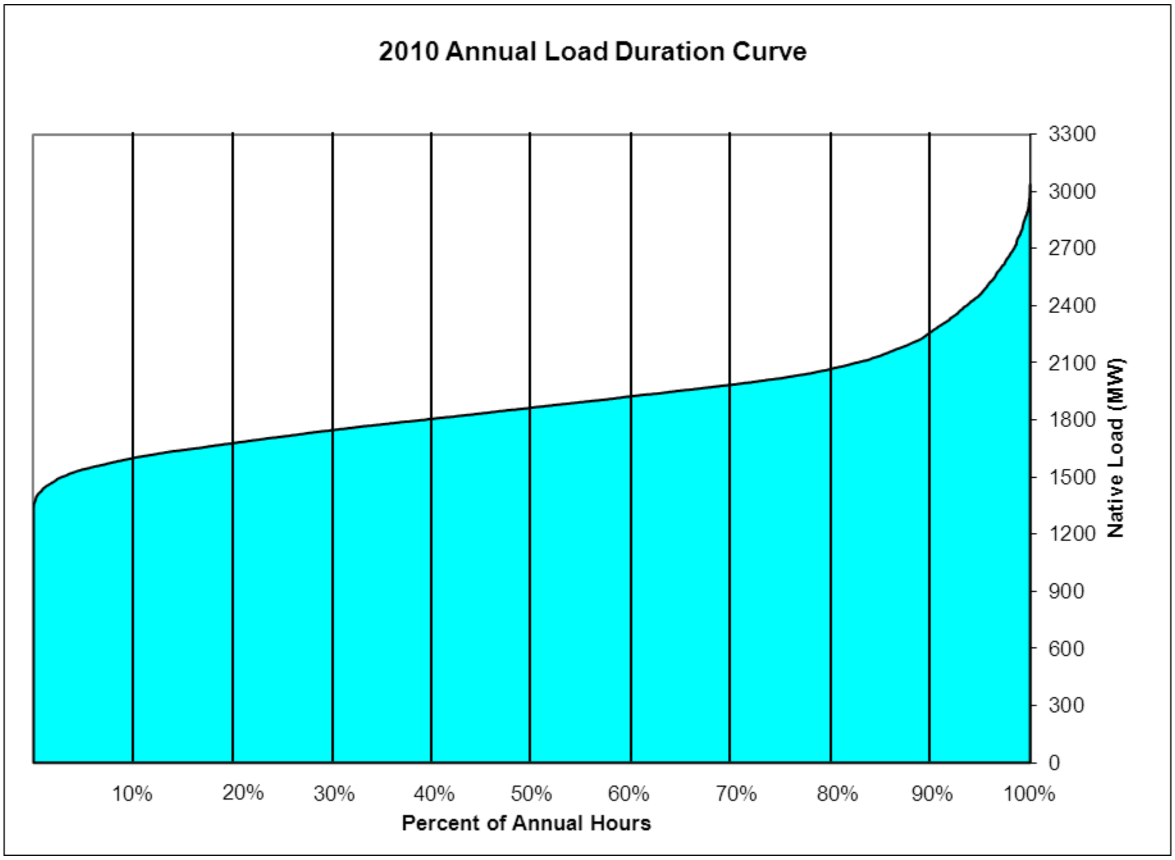
11/20/2010	1698	1665	1644	1640	1653	1753	1770	1722	1719	1668	1744	1687
11/21/2010	1617	1557	1524	1495	1490	1502	1508	1534	1545	1592	1601	1637
11/21/2010	1613	1609	1610	1606	1638	1779	1771	1693	1716	1667	1676	1597
11/22/2010	1551	1506	1535	1526	1520	1636	1693	1817	1849	1868	1961	2023
11/22/2010	1944	1946	1938	1917	1925	2006	1989	1960	1929	1849	1838	1773
11/23/2010	1714	1696	1684	1673	1705	1749	1867	1955	1931	1970	2011	1953
11/23/2010	1998	1978	1963	1956	1957	2042	2085	2005	2012	1965	1915	1863
11/24/2010	1815	1770	1701	1678	1694	1724	1821	1854	1817	1891	1938	1933
11/24/2010	1921	1909	1886	1873	1873	1935	1939	1884	1879	1841	1765	1704
11/25/2010	1658	1599	1556	1514	1509	1509	1524	1451	1440	1493	1518	1538
11/25/2010	1526	1483	1464	1456	1427	1503	1544	1509	1513	1517	1517	1540
11/26/2010	1478	1467	1462	1459	1454	1444	1481	1493	1508	1541	1594	1607
11/26/2010	1625	1654	1644	1635	1649	1780	1837	1769	1785	1765	1753	1720
11/27/2010	1629	1642	1602	1612	1602	1612	1641	1668	1682	1732	1758	1751
11/27/2010	1732	1705	1679	1697	1702	1783	1852	1799	1776	1742	1756	1748
11/28/2010	1692	1646	1604	1586	1602	1608	1623	1643	1654	1707	1706	1724
11/28/2010	1723	1711	1678	1659	1641	1783	1877	1842	1837	1800	1781	1732
11/29/2010	1685	1676	1660	1645	1667	1724	1836	1865	1897	1901	1907	1926
11/29/2010	1912	1900	1874	1830	1864	1969	2000	1955	2004	1951	1838	1816
11/30/2010	1760	1742	1705	1693	1724	1761	1888	1866	1901	1958	1983	2001
11/30/2010	1991	1994	1977	1957	1997	2053	2069	2031	2013	2006	1961	1915

Date	HOUR ENDING											
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
12/1/2010	1847	1853	1787	1778	1832	1915	1979	1988	2015	1997	1996	1997
12/1/2010	2016	1985	1965	1935	1927	2018	2058	1980	1983	2021	1957	1921
12/2/2010	1827	1784	1787	1740	1752	1838	1922	1995	2034	2030	2074	2056
12/2/2010	2024	2054	2007	1965	2028	2071	2054	2006	1964	1965	1949	1911
12/3/2010	1859	1811	1770	1772	1772	1832	1906	1976	1910	1955	1963	1973
12/3/2010	1964	1942	1880	1819	1841	1942	1975	1943	1901	1919	1902	1802
12/4/2010	1772	1692	1690	1671	1660	1678	1721	1731	1731	1799	1813	1816
12/4/2010	1767	1761	1790	1769	1785	1887	1949	1916	1898	1879	1859	1843
12/5/2010	1733	1635	1640	1652	1646	1642	1688	1696	1729	1779	1831	1771
12/5/2010	1735	1766	1806	1812	1826	1935	1986	1993	1925	1962	1952	1882
12/6/2010	1848	1837	1791	1820	1827	1854	1948	2011	2025	2091	2127	2148
12/6/2010	2101	2099	2055	2019	2013	2139	2183	2140	2125	2106	2032	1958
12/7/2010	1892	1878	1795	1843	1886	1907	1934	1979	1977	2079	2039	2061
12/7/2010	1985	1983	1970	1958	1977	2095	2164	2139	2160	2151	2058	2048
12/8/2010	1957	1967	2005	1957	1995	2038	2095	2171	2086	2172	2122	2160
12/8/2010	2141	2091	2077	2075	2061	2164	2212	2163	2172	2137	2175	2128
12/9/2010	2017	1977	1951	1937	1952	1992	2047	2038	2077	2112	2131	2132
12/9/2010	2093	2061	2071	2062	2061	2132	2171	2159	2180	2209	2106	2096
12/10/2010	2013	1998	1907	1905	1888	1950	1978	2011	2031	2060	2117	2044
12/10/2010	2064	2063	1960	1853	1876	2004	2073	1996	1992	2027	1994	1934
12/11/2010	1833	1752	1741	1733	1718	1733	1725	1758	1766	1798	1859	1874
12/11/2010	1871	1883	1904	1868	1890	1977	2009	2009	1974	1942	1938	1812
12/12/2010	1760	1742	1717	1672	1689	1679	1729	1738	1795	1826	1827	1828
12/12/2010	1881	1879	1893	1805	1854	1934	2004	1996	1956	1951	1938	1880
12/13/2010	1793	1769	1769	1791	1810	1888	1947	1985	2022	1995	2039	2053
12/13/2010	2031	2069	2044	1991	1964	2029	2126	2127	2099	2060	1995	1941
12/14/2010	1848	1791	1799	1801	1821	1921	1958	2040	2072	2117	2090	2101
12/14/2010	2113	2105	2087	2016	1965	2145	2164	2205	2186	2150	2102	2025
12/15/2010	1984	1932	1886	1906	1896	1978	2057	2147	2188	2240	2174	2187
12/15/2010	2144	2104	2148	2027	2065	2131	2223	2169	2145	2150	2113	2050
12/16/2010	1971	1948	1925	1911	1883	1960	2021	2055	2078	2079	2061	2012
12/16/2010	2039	1950	2029	2013	2017	2127	2200	2179	2176	2134	2082	2041
12/17/2010	1961	1899	1861	1908	1925	1972	2078	2164	2139	2176	2147	2134
12/17/2010	2063	2045	2061	2037	2055	2144	2225	2195	2160	2158	2159	2142
12/18/2010	2093	1989	1968	1957	1948	1929	2011	2027	2038	2095	2099	2073
12/18/2010	1996	2003	1958	1970	1932	2025	2156	2094	2040	2026	2030	1968
12/19/2010	1933	1892	1859	1867	1847	1835	1845	1902	1926	1926	1963	1938
12/19/2010	1876	1847	1818	1837	1848	1974	2081	2041	2058	2039	2025	1965
12/20/2010	1908	1892	1856	1874	1899	1920	2018	2087	2090	2126	2100	2102
12/20/2010	2104	2082	2055	2020	1981	2083	2147	2122	2098	2075	2019	2010
12/21/2010	1923	1825	1810	1807	1830	1910	1942	1983	2003	2083	2116	2106
12/21/2010	2102	2112	2059	2043	2036	2124	2160	2044	2086	2059	2020	1981
12/22/2010	1842	1842	1816	1789	1786	1815	1919	1987	1974	2017	1987	2005
12/22/2010	2035	2040	1981	1966	1859	1975	2061	2015	2039	2023	1945	1947
12/23/2010	1821	1761	1736	1733	1739	1779	1815	1842	1859	1882	1900	1918
12/23/2010	1883	1934	1891	1889	1881	1950	1958	1887	1890	1880	1859	1771
12/24/2010	1690	1665	1583	1566	1547	1573	1568	1550	1573	1608	1625	1626
12/24/2010	1597	1604	1594	1605	1608	1686	1727	1666	1661	1660	1692	1674
12/25/2010	1614	1578	1534	1520	1503	1497	1540	1518	1514	1523	1527	1525
12/25/2010	1516	1513	1500	1506	1554	1653	1696	1633	1651	1658	1706	1624
12/26/2010	1582	1547	1532	1519	1489	1509	1543	1569	1607	1653	1652	1675
12/26/2010	1639	1649	1656	1653	1694	1815	1889	1856	1856	1832	1832	1771
12/27/2010	1715	1715	1688	1668	1704	1736	1769	1819	1873	1901	1910	1910
12/27/2010	1894	1903	1940	1937	1923	1995	2089	2061	2044	2012	2021	1932
12/28/2010	1904	1854	1853	1848	1846	1893	1937	1960	2004	2037	2042	2033
12/28/2010	2032	2033	2008	1957	1929	2057	2146	2110	2116	2157	2114	2017
12/29/2010	1956	1891	1910	1945	1856	1985	1993	2005	2016	2024	2053	2031
12/29/2010	2004	2004	1947	1947	1926	2022	2123	2058	2064	2014	2007	1968
12/30/2010	1879	1807	1764	1761	1796	1794	1839	1859	1945	1938	1921	1932
12/30/2010	1914	1961	1947	1868	1910	1952	2017	2011	1971	1938	1891	1828
12/31/2010	1768	1730	1692	1693	1713	1692	1717	1716	1758	1836	1826	1840
12/31/2010	1796	1875	1830	1761	1727	1787	1780	1705	1642	1633	1651	1621


2010 Annual Load Duration Curve
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Native Load (MW)
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Annual Hours

2011 Hourly Market Price

2011 Hourly Market Price: The hourly Market Price is stated in $/MWh, Hour Ending (HE), and Central Standard Time (CST).

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
1/1/2011	27.17	27.30	26.55	24.91	24.43	24.69	26.40	29.53	32.19	40.65	52.84	51.12
1/1/2011	42.02	37.26	31.43	30.33	32.66	60.13	76.99	61.37	57.62	48.89	46.92	43.84
1/2/2011	35.32	32.71	31.05	29.70	28.82	28.21	30.19	30.65	35.29	40.10	46.68	44.40
1/2/2011	39.07	33.21	29.38	29.22	31.72	55.72	77.39	62.58	55.96	46.78	44.28	38.59
1/3/2011	43.00	41.06	39.88	37.37	39.89	43.47	60.05	64.66	62.04	60.19	61.02	57.86
1/3/2011	48.84	44.71	41.45	38.69	40.23	64.17	83.99	70.20	63.95	59.49	49.76	44.67
1/4/2011	32.03	29.93	27.90	27.89	28.65	33.18	48.60	57.86	55.66	53.25	53.08	51.68
1/4/2011	45.98	39.95	36.07	32.64	33.33	56.93	72.69	63.30	58.34	51.74	41.58	33.58
1/5/2011	34.83	32.59	30.21	30.81	33.49	39.49	54.24	71.65	67.73	63.98	66.26	61.30
1/5/2011	55.33	47.31	39.68	36.29	37.51	59.45	77.47	68.11	60.79	53.38	42.33	34.29
1/6/2011	29.78	28.71	28.74	27.14	28.59	34.17	46.58	57.89	56.33	53.13	56.16	54.47
1/6/2011	51.40	46.92	40.37	35.76	37.73	59.08	75.09	63.38	57.05	51.11	42.64	29.97
1/7/2011	26.57	25.80	25.55	25.04	25.35	27.18	37.19	52.35	54.45	54.26	57.37	56.40
1/7/2011	52.64	50.95	41.29	35.52	36.27	58.64	74.07	58.28	54.16	52.35	48.00	36.90
1/8/2011	39.44	37.71	34.23	32.70	32.32	35.14	42.53	53.09	57.04	61.75	63.18	58.12
1/8/2011	49.54	43.59	36.64	32.68	34.58	59.52	74.92	65.11	59.08	50.20	46.37	38.98
1/9/2011	36.78	35.13	32.77	31.42	30.08	29.61	30.19	32.54	37.07	44.85	46.56	44.79
1/9/2011	39.41	33.83	29.15	28.13	28.47	53.31	76.17	65.39	60.90	51.39	46.10	37.54
1/10/2011	31.78	27.90	29.30	27.49	28.74	33.15	41.53	59.25	59.57	56.74	59.69	56.93
1/10/2011	55.02	47.51	39.20	35.23	36.35	59.77	78.47	62.34	60.07	51.82	42.81	37.70
1/11/2011	27.92	26.96	26.34	26.08	26.68	28.61	43.12	53.54	51.63	48.15	50.17	47.97
1/11/2011	44.52	41.87	37.20	33.67	33.07	50.81	64.75	53.56	47.65	40.91	32.46	35.32
1/12/2011	27.33	25.20	25.77	25.99	26.59	29.75	41.28	48.38	47.05	45.47	45.94	43.73
1/12/2011	40.08	33.43	28.51	26.41	25.84	44.57	58.18	48.19	45.54	37.32	29.26	28.29
1/13/2011	31.71	29.25	27.62	26.61	27.32	32.22	42.06	52.05	46.00	45.71	45.41	43.61
1/13/2011	35.58	32.01	27.39	26.33	26.52	43.62	49.94	45.82	42.09	36.21	29.22	27.74
1/14/2011	26.36	24.94	27.10	24.62	26.54	30.21	36.79	48.74	44.78	45.98	45.42	41.84
1/14/2011	37.36	31.82	27.94	26.01	25.67	39.17	45.54	43.59	37.36	30.17	27.25	27.39
1/15/2011	29.40	28.32	25.91	24.97	25.52	29.58	33.32	32.20	32.27	38.95	40.19	34.42
1/15/2011	30.13	27.48	28.36	28.57	29.25	36.36	45.24	40.73	35.36	31.31	27.17	25.31
1/16/2011	24.17	23.22	23.08	22.64	22.19	21.47	22.65	24.98	25.95	28.20	28.96	30.13
1/16/2011	28.45	27.48	26.41	26.19	27.11	43.95	51.84	50.67	46.48	38.65	28.60	25.54
1/17/2011	23.18	22.80	22.34	22.19	22.65	23.96	26.65	40.56	41.08	45.26	47.60	43.86
1/17/2011	40.78	36.72	30.59	27.93	27.59	42.04	47.38	44.97	41.73	37.22	28.44	24.84
1/18/2011	25.08	23.72	23.13	23.11	23.74	27.79	36.74	48.08	44.47	45.79	44.78	40.32
1/18/2011	38.12	36.05	28.72	26.47	27.18	40.10	45.98	41.48	40.69	38.00	28.64	26.11
1/19/2011	24.13	23.51	22.63	22.41	22.91	24.65	30.70	42.67	35.71	35.89	35.94	34.03
1/19/2011	29.52	27.61	24.68	24.15	24.67	33.19	41.03	43.66	39.51	32.13	26.15	24.08
1/20/2011	22.41	20.79	20.82	20.67	21.21	22.42	25.80	32.85	31.35	32.15	32.84	32.92
1/20/2011	30.95	29.09	25.88	24.96	25.32	33.54	40.28	33.46	30.87	27.52	25.87	23.39
1/21/2011	22.86	21.49	21.59	21.51	22.15	24.31	28.78	40.85	37.24	36.63	37.27	34.75
1/21/2011	30.52	28.85	25.73	24.42	24.39	30.43	37.18	32.41	28.21	25.06	24.19	22.64
1/22/2011	21.83	21.12	20.53	19.53	19.68	19.89	22.18	24.60	25.44	31.94	29.07	27.06
1/22/2011	25.26	23.76	22.61	21.51	21.98	27.77	39.72	29.49	28.06	24.60	22.32	20.08
1/23/2011	18.94	17.54	17.51	16.72	16.78	16.52	16.97	19.21	19.80	21.46	22.53	22.41
1/23/2011	22.53	21.81	20.91	20.17	21.22	28.22	35.58	31.93	30.41	26.10	22.98	19.90
1/24/2011	18.77	17.59	18.35	17.81	19.20	22.59	26.17	35.04	30.94	34.71	35.29	33.96
1/24/2011	31.15	28.66	26.90	25.26	26.87	34.74	46.56	42.05	35.60	31.03	27.28	23.38
1/25/2011	23.13	22.13	21.31	21.36	22.39	26.16	33.69	47.86	42.66	42.93	43.58	43.61
1/25/2011	41.23	39.79	35.34	31.19	34.60	45.76	62.92	57.70	49.00	44.77	38.33	29.26
1/26/2011	27.65	26.23	26.35	26.18	27.16	29.79	42.99	57.11	52.08	51.50	47.08	44.00
1/26/2011	43.02	37.65	31.38	28.43	29.09	45.13	61.25	52.14	46.72	38.72	34.14	26.99
1/27/2011	25.55	24.91	24.51	23.94	25.31	27.74	35.46	45.82	44.52	44.50	44.51	43.16
1/27/2011	41.60	37.97	33.55	30.36	31.30	43.16	54.79	50.32	46.56	43.68	40.83	37.91
1/28/2011	31.22	29.59	30.39	29.25	30.63	34.48	44.03	62.13	51.93	51.48	49.69	45.38
1/28/2011	43.49	43.11	36.52	31.42	31.77	43.39	58.50	51.62	46.30	41.82	37.60	33.13
1/29/2011	32.98	32.53	31.29	29.61	29.09	28.93	32.67	38.36	41.13	49.83	51.51	45.39
1/29/2011	40.10	36.25	31.41	29.09	29.21	40.53	61.25	52.64	47.45	39.26	35.05	33.77
1/30/2011	32.16	31.19	29.99	29.05	28.51	28.14	29.27	31.72	33.75	40.96	40.15	37.51
1/30/2011	33.75	30.83	28.07	27.25	27.42	38.60	57.39	48.35	45.37	39.89	35.51	30.23
1/31/2011	26.42	26.37	26.00	26.00	26.50	28.11	42.88	59.70	51.80	49.11	44.51	42.90
1/31/2011	39.40	36.47	32.00	29.05	30.08	37.40	58.45	52.13	43.66	41.38	32.90	28.86

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
2/1/2011	26.96	26.02	25.51	25.52	26.38	28.21	40.63	49.95	44.25	43.99	42.55	41.52
2/1/2011	38.19	35.14	30.76	27.85	28.69	34.89	50.21	45.36	41.27	39.07	32.94	29.05
2/2/2011	25.82	25.08	23.94	23.66	24.26	25.97	34.58	44.28	40.49	38.02	37.97	35.37
2/2/2011	32.45	30.25	27.62	25.92	26.82	31.27	44.22	44.64	41.06	36.26	30.36	27.72
2/3/2011	26.36	24.60	24.37	24.24	24.51	27.74	38.58	47.77	44.42	43.53	42.08	41.43
2/3/2011	37.33	32.75	31.03	28.78	28.77	33.25	44.72	43.62	41.14	36.45	29.29	27.13
2/4/2011	24.49	23.75	23.27	23.11	23.17	23.87	27.45	42.23	37.23	39.47	37.84	37.31
2/4/2011	37.14	33.89	30.15	27.27	26.93	29.37	39.68	37.38	37.26	30.92	27.04	26.27
2/5/2011	27.38	26.98	26.05	25.35	25.28	26.16	27.69	32.94	36.45	43.81	48.18	45.25
2/5/2011	40.84	33.40	31.86	29.92	30.31	38.86	55.12	53.21	52.49	46.04	37.54	32.78
2/6/2011	32.14	30.86	30.00	29.13	28.95	27.83	29.72	33.09	34.05	37.63	37.86	36.75
2/6/2011	35.03	32.78	30.17	29.01	30.42	37.69	48.64	50.62	47.54	43.48	36.84	31.11
2/7/2011	27.42	27.53	28.09	28.25	28.08	31.58	43.75	53.28	47.17	47.02	47.64	47.00
2/7/2011	43.30	37.90	34.00	31.13	32.74	37.99	60.46	55.68	47.02	42.85	32.96	30.21
2/8/2011	27.12	25.92	25.26	25.32	26.19	31.15	41.46	48.29	44.80	43.58	48.11	49.23
2/8/2011	41.38	37.65	35.06	31.16	35.24	38.00	51.38	47.71	42.92	37.40	33.62	28.72
2/9/2011	26.95	26.48	26.47	26.28	27.68	32.73	45.62	50.53	48.03	47.94	47.79	46.37
2/9/2011	43.69	39.00	34.87	30.85	31.70	36.90	57.60	58.64	46.39	41.10	39.06	32.05
2/10/2011	31.30	30.00	28.46	28.43	29.76	34.75	47.39	53.40	52.79	52.21	49.24	45.45
2/10/2011	42.00	37.15	34.39	30.52	30.52	34.79	52.79	56.87	46.72	38.52	40.26	36.97
2/11/2011	28.59	27.85	27.26	27.67	27.59	30.61	37.00	49.58	47.29	45.91	45.02	40.26
2/11/2011	36.88	33.33	31.29	27.49	26.91	29.19	43.43	43.75	39.59	33.51	32.43	29.86
2/12/2011	28.62	28.48	27.03	26.71	26.18	31.69	32.87	33.51	36.52	40.67	41.49	38.69
2/12/2011	35.68	31.04	29.19	27.72	28.18	30.38	41.83	41.74	40.04	36.59	30.86	27.73
2/13/2011	31.57	34.50	33.96	32.14	31.06	30.84	33.52	30.67	29.59	30.71	29.89	29.55
2/13/2011	29.35	28.74	25.57	25.81	25.83	27.86	40.34	42.57	39.16	34.04	27.47	27.77
2/14/2011	25.21	24.13	24.06	23.70	26.24	26.82	32.22	43.44	43.98	45.27	45.27	45.28
2/14/2011	41.97	37.22	34.07	29.62	30.02	34.61	52.05	57.13	45.28	40.69	33.62	28.06
2/15/2011	28.50	27.37	27.54	27.11	28.09	30.80	41.02	48.01	43.75	44.90	44.35	36.65
2/15/2011	34.62	32.85	29.48	27.90	28.66	29.17	45.33	50.42	44.31	35.08	32.33	28.00
2/16/2011	26.37	26.31	26.85	27.02	28.78	31.45	34.34	49.16	48.52	48.42	48.43	48.74
2/16/2011	38.94	37.84	32.70	28.64	30.83	34.46	48.78	56.48	47.74	45.68	37.19	28.70
2/17/2011	27.07	26.51	26.53	26.25	27.31	29.65	34.54	48.72	46.68	46.77	47.15	43.26
2/17/2011	37.80	34.56	30.73	27.14	26.97	30.36	46.48	49.23	46.84	37.97	31.06	27.48
2/18/2011	27.60	27.69	27.14	27.06	27.90	30.08	35.74	46.64	43.95	43.26	43.78	38.84
2/18/2011	38.94	35.07	31.48	27.68	27.69	31.49	44.18	46.00	44.03	37.24	33.79	29.95
2/19/2011	28.22	27.26	26.46	25.13	25.05	26.10	27.82	30.32	35.11	43.32	44.91	41.84
2/19/2011	33.84	29.22	28.34	26.68	27.06	29.18	39.27	44.90	39.35	35.78	30.50	27.35
2/20/2011	24.23	24.41	23.42	22.48	21.83	22.20	23.68	23.95	24.76	26.61	26.51	26.32
2/20/2011	25.99	25.29	24.52	23.66	24.17	27.62	39.16	43.64	37.39	30.28	25.60	23.92
2/21/2011	22.69	22.86	22.24	22.21	23.35	24.71	30.99	41.62	41.41	42.87	41.90	41.34
2/21/2011	37.71	36.82	33.43	30.29	32.06	36.63	50.14	56.51	45.58	37.41	31.42	26.64
2/22/2011	26.13	25.50	25.48	25.60	26.68	28.75	36.14	42.94	42.02	42.74	40.74	37.42
2/22/2011	34.44	30.93	30.03	27.17	27.19	30.49	42.60	49.05	40.66	35.28	31.29	28.09
2/23/2011	26.33	25.90	25.67	25.67	26.24	30.01	33.94	45.26	43.61	44.07	42.92	41.32
2/23/2011	37.53	36.51	33.87	29.44	29.53	31.77	45.44	52.49	43.18	40.54	35.87	30.15
2/24/2011	28.67	28.69	27.73	27.53	28.21	30.78	39.78	46.21	41.02	40.65	40.55	40.70
2/24/2011	37.04	38.06	34.40	29.58	29.13	33.24	44.18	52.55	44.59	40.71	37.21	36.17
2/25/2011	31.44	30.53	28.63	28.52	29.02	29.31	36.07	46.19	44.01	42.55	41.83	39.86
2/25/2011	36.55	33.88	31.05	27.96	27.58	29.32	41.04	42.14	39.85	33.97	36.14	31.00
2/26/2011	31.48	31.56	30.62	30.29	29.90	31.21	34.52	35.45	44.03	49.14	48.16	44.15
2/26/2011	38.17	33.83	30.27	29.08	29.52	31.78	48.08	50.15	46.60	44.14	37.47	30.83
2/27/2011	31.54	31.50	30.65	29.08	27.81	31.76	32.35	33.25	37.00	43.11	40.90	40.13
2/27/2011	35.13	34.65	32.15	30.35	30.56	33.26	44.18	49.60	46.16	43.96	36.02	30.36
2/28/2011	27.87	27.05	26.51	26.36	26.75	31.77	42.08	44.50	46.24	49.30	45.49	45.65
2/28/2011	41.87	40.02	36.98	33.99	33.28	39.43	48.98	55.91	47.62	40.09	35.08	33.54

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
3/1/2011	33.51	32.15	32.31	32.28	32.51	37.44	50.54	52.93	54.00	54.22	54.81	52.05
3/1/2011	47.43	45.16	43.60	40.16	36.94	40.70	52.81	65.74	51.77	47.80	40.06	37.66
3/2/2011	32.31	30.73	30.32	30.34	31.28	36.39	46.61	49.48	49.91	49.46	48.34	47.31
3/2/2011	43.09	40.47	39.52	35.20	34.83	37.31	47.35	51.84	47.31	44.34	36.92	34.50
3/3/2011	33.23	31.85	31.83	31.79	33.21	38.36	52.13	56.27	55.17	54.45	55.39	51.75
3/3/2011	47.09	46.07	42.14	35.09	33.66	35.47	47.33	57.17	51.43	45.75	37.35	32.93
3/4/2011	31.03	29.24	29.16	29.18	29.90	31.98	40.66	47.14	47.80	47.16	45.48	43.28
3/4/2011	38.14	33.50	30.92	28.79	28.21	29.31	35.99	44.56	39.91	34.41	29.28	29.15
3/5/2011	29.85	28.94	28.35	26.97	26.52	28.20	30.94	31.34	36.48	38.38	37.77	34.06
3/5/2011	29.97	27.71	26.82	26.15	26.08	27.38	31.80	38.72	33.41	31.76	27.95	26.54
3/6/2011	26.28	26.04	25.73	25.11	25.93	26.60	28.07	26.54	27.45	28.37	28.05	27.65
3/6/2011	26.73	26.20	25.31	24.56	25.15	26.68	34.02	43.69	36.26	31.71	26.23	24.56
3/7/2011	23.56	22.85	22.78	23.35	24.42	26.98	39.09	37.48	40.95	42.26	39.11	38.01
3/7/2011	36.08	32.91	29.38	27.71	27.27	28.22	34.14	44.00	37.56	30.13	26.18	25.15
3/8/2011	24.08	23.32	23.29	23.50	24.77	28.73	41.36	37.58	38.65	37.73	37.65	36.61
3/8/2011	35.14	32.40	30.42	29.16	28.93	30.17	35.94	42.60	36.49	30.15	26.31	24.84
3/9/2011	23.44	22.45	22.48	22.38	23.66	29.64	39.59	38.10	42.51	42.68	42.69	40.33
3/9/2011	41.43	38.01	34.79	31.28	30.63	33.09	44.32	51.01	43.60	36.58	28.24	24.81
3/10/2011	22.17	20.98	20.80	20.84	21.57	25.68	35.26	35.65	32.70	32.60	31.98	34.34
3/10/2011	33.73	33.52	31.89	29.59	29.06	29.09	35.88	40.11	35.61	30.22	25.64	23.47
3/11/2011	19.89	20.05	20.74	20.64	21.65	26.55	34.76	38.68	41.76	41.75	42.57	40.62
3/11/2011	42.49	38.68	35.95	30.89	30.14	30.23	38.68	42.32	37.20	29.80	25.37	23.00
3/12/2011	23.55	23.36	23.17	23.04	22.72	22.56	26.87	27.55	31.21	32.71	33.10	32.28
3/12/2011	31.43	30.65	29.56	28.56	28.46	30.08	34.30	43.42	32.65	30.47	27.64	24.34
3/13/2011	24.06	23.53	23.75	23.62	23.69	24.38	27.18	26.82	28.17	29.67	30.26	30.10
3/13/2011	29.67	29.65	28.32	28.20	29.31	31.59	37.79	52.55	38.78	31.71	26.78	24.15
3/14/2011	23.77	23.28	23.26	23.54	24.88	39.93	49.70	42.46	43.05	48.11	45.20	45.96
3/14/2011	45.99	44.59	43.17	40.00	36.01	35.89	45.34	57.30	43.23	34.32	32.03	29.40
3/15/2011	24.65	25.87	27.16	27.23	30.74	41.24	46.78	43.66	42.06	42.06	41.95	41.04
3/15/2011	42.18	35.52	31.70	29.87	29.60	29.70	37.17	44.56	39.12	29.24	27.80	26.58
3/16/2011	28.43	27.79	28.92	29.01	32.69	46.30	48.75	42.52	42.39	42.38	42.38	42.38
3/16/2011	39.43	35.83	33.62	30.64	29.84	29.77	35.66	42.38	35.84	31.80	30.79	27.81
3/17/2011	26.11	25.52	26.61	27.21	28.79	40.55	46.48	41.25	41.40	41.75	41.58	39.37
3/17/2011	35.59	32.88	29.74	29.99	29.87	28.01	32.05	43.37	34.23	28.72	25.68	24.08
3/18/2011	22.20	21.39	21.40	22.14	23.74	31.65	39.61	36.99	36.57	36.11	34.01	32.68
3/18/2011	32.81	30.86	29.71	27.54	26.75	26.11	29.27	38.27	32.48	27.40	24.49	23.19
3/19/2011	28.61	27.63	27.66	27.50	27.72	29.29	32.19	32.25	36.37	39.43	40.15	39.86
3/19/2011	36.28	31.94	29.58	29.02	29.37	30.95	35.03	42.99	39.19	32.83	25.77	25.93
3/20/2011	27.71	27.24	29.12	27.45	28.43	29.69	28.36	28.23	30.41	30.79	30.97	30.32
3/20/2011	30.18	28.14	27.02	27.33	28.25	29.80	34.72	46.04	39.00	31.51	25.67	26.78
3/21/2011	27.45	26.60	25.62	26.18	30.49	39.16	47.07	45.22	44.63	43.81	42.98	40.38
3/21/2011	38.23	35.33	35.31	32.19	31.60	31.75	37.36	48.40	38.53	29.89	26.87	25.31
3/22/2011	28.52	27.77	28.11	28.47	29.96	37.30	48.78	41.06	40.11	40.18	40.38	40.65
3/22/2011	37.98	36.15	32.30	30.52	29.58	28.56	30.00	41.95	34.77	28.75	26.66	25.15
3/23/2011	30.18	30.01	30.00	30.46	33.04	39.95	47.50	40.31	40.11	38.90	40.33	37.41
3/23/2011	35.85	36.17	31.67	29.63	28.34	28.12	30.84	41.14	36.08	29.61	28.53	28.53
3/24/2011	22.97	21.93	21.97	21.91	24.34	31.89	40.67	37.53	37.17	36.40	37.55	35.26
3/24/2011	34.22	31.85	29.97	28.80	29.43	30.15	33.51	44.41	39.72	30.14	25.93	24.63
3/25/2011	25.16	24.34	25.16	25.32	28.03	42.77	47.31	43.48	42.64	41.82	39.28	33.99
3/25/2011	32.79	30.31	27.24	27.88	26.83	26.52	29.53	41.42	33.11	27.30	25.61	24.68
3/26/2011	28.74	26.74	25.08	25.56	28.74	29.81	31.46	30.91	33.61	35.79	34.21	30.18
3/26/2011	28.30	28.86	28.33	25.14	24.03	24.89	28.68	37.02	31.65	28.41	24.58	23.57
3/27/2011	21.88	21.77	22.45	22.50	22.99	22.95	29.72	25.02	26.07	26.80	27.28	26.78
3/27/2011	26.86	25.78	25.13	25.47	25.90	26.40	30.20	35.75	31.26	27.90	25.32	23.56
3/28/2011	24.57	24.05	24.37	24.15	26.73	39.24	57.66	51.06	47.08	46.28	46.01	43.47
3/28/2011	37.47	37.75	32.90	32.64	29.75	30.18	33.25	45.93	38.27	29.16	28.22	28.20
3/29/2011	29.93	28.51	28.56	30.02	31.73	46.63	55.68	46.31	40.43	42.53	40.76	36.70
3/29/2011	33.96	32.50	30.38	29.37	29.40	28.24	29.71	40.53	33.04	28.38	28.19	27.12
3/30/2011	28.16	27.55	29.29	29.45	30.72	43.70	53.37	44.72	45.09	40.18	39.61	38.96
3/30/2011	36.34	34.16	32.40	30.40	30.97	29.93	30.07	39.89	32.55	27.00	27.57	24.25
3/31/2011	23.60	23.70	24.57	26.14	30.83	44.25	43.79	36.62	37.49	38.89	38.25	38.17
3/31/2011	38.50	39.30	38.17	36.46	34.43	31.50	32.51	36.24	32.48	29.08	30.58	29.89

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
4/1/2011	21.47	17.81	18.00	19.35	19.99	29.75	29.93	30.44	31.09	31.65	30.82	30.51
4/1/2011	30.81	31.14	31.53	29.13	29.60	28.75	27.36	27.83	28.39	23.69	20.30	18.48
4/2/2011	14.86	14.58	13.50	13.64	14.75	15.64	23.39	24.95	28.04	27.94	28.01	28.00
4/2/2011	27.97	27.20	26.34	26.34	26.54	25.47	24.37	28.49	25.74	24.65	19.30	17.51
4/3/2011	16.69	16.47	14.38	13.59	14.80	18.51	22.81	23.85	24.27	24.29	24.45	25.05
4/3/2011	23.82	23.20	21.83	21.86	23.02	21.86	22.41	27.44	23.85	21.68	20.46	19.05
4/4/2011	17.49	17.37	17.44	17.50	18.18	31.55	39.58	38.15	43.19	43.28	42.65	44.41
4/4/2011	44.50	45.93	40.28	37.74	37.32	30.06	29.92	37.06	31.72	25.50	24.68	21.68
4/5/2011	22.94	20.66	20.34	24.75	24.81	36.90	33.44	34.48	33.58	35.96	37.58	36.75
4/5/2011	41.62	42.11	40.40	40.12	36.99	30.70	28.89	35.50	32.08	25.16	20.36	17.57
4/6/2011	19.53	18.06	17.00	17.44	19.50	27.24	30.81	33.91	37.72	38.21	38.64	38.46
4/6/2011	41.91	41.95	37.94	37.74	37.05	33.03	33.39	37.23	34.36	30.57	25.49	21.96
4/7/2011	26.56	31.56	33.31	26.40	28.28	43.25	51.00	50.70	47.52	46.46	45.60	47.42
4/7/2011	49.11	46.77	40.76	38.42	36.72	34.53	35.15	46.51	44.97	33.66	28.61	34.10
4/8/2011	31.22	30.41	29.12	27.94	32.36	47.24	57.78	54.57	53.01	56.44	49.75	45.73
4/8/2011	44.40	42.92	35.82	35.37	37.05	34.82	33.20	43.60	39.79	43.94	37.47	32.89
4/9/2011	30.89	34.32	31.24	29.98	32.61	42.03	41.13	50.02	53.32	44.40	44.34	45.20
4/9/2011	39.17	37.93	34.79	32.06	35.82	34.97	31.90	39.88	38.92	32.07	35.25	29.77
4/10/2011	38.19	37.81	35.38	35.71	36.10	37.90	37.75	39.73	43.58	35.22	34.57	34.10
4/10/2011	33.58	34.09	33.47	33.70	34.10	33.68	33.58	42.99	39.34	33.65	36.45	35.38
4/11/2011	31.64	31.35	33.78	33.14	37.00	49.60	58.50	78.79	64.63	55.13	55.04	51.65
4/11/2011	50.34	47.70	44.11	41.67	39.79	37.38	38.13	43.04	43.30	36.13	33.43	30.46
4/12/2011	24.89	23.36	22.70	23.70	27.47	37.79	36.94	38.08	39.81	41.88	42.13	44.57
4/12/2011	46.83	47.08	40.75	38.41	37.67	32.41	32.86	42.87	44.14	32.22	27.48	25.96
4/13/2011	19.10	18.36	17.91	18.54	24.42	39.13	39.04	38.64	42.45	43.77	43.47	44.36
4/13/2011	43.47	42.07	41.93	42.06	44.32	36.13	34.83	42.54	46.36	32.02	26.24	25.63
4/14/2011	33.77	33.47	31.57	34.83	39.71	52.73	47.54	54.14	51.86	49.64	52.86	52.25
4/14/2011	52.04	58.35	58.45	51.79	54.27	47.45	46.02	52.33	51.10	37.13	36.09	30.71
4/15/2011	34.87	35.97	36.05	35.25	39.48	48.19	48.29	45.13	43.38	45.12	45.19	44.70
4/15/2011	44.29	42.13	37.21	42.02	34.30	29.37	29.31	42.41	38.18	28.42	28.13	29.76
4/16/2011	27.84	27.29	26.85	28.08	28.51	29.21	31.24	40.35	47.74	44.51	46.55	37.77
4/16/2011	36.44	32.31	30.43	29.31	30.11	29.29	28.86	44.68	39.52	33.07	27.88	27.36
4/17/2011	25.99	25.48	25.13	24.28	25.78	27.53	27.88	29.38	30.63	31.46	32.77	28.91
4/17/2011	29.27	28.78	28.55	27.66	27.53	26.93	26.61	46.97	40.91	27.38	29.42	28.56
4/18/2011	21.74	21.61	21.66	22.67	25.32	36.71	41.60	41.94	41.92	42.18	42.37	42.06
4/18/2011	42.31	43.30	37.92	34.58	32.50	29.15	28.16	40.51	40.51	29.10	22.84	22.05
4/19/2011	20.99	20.24	20.34	20.72	22.34	33.83	40.36	41.02	42.16	42.47	41.89	42.23
4/19/2011	42.13	42.24	42.61	40.83	36.96	32.18	28.36	42.54	42.79	31.95	23.63	21.52
4/20/2011	18.71	17.56	17.53	17.81	18.97	30.76	34.16	35.00	37.44	38.67	37.34	36.76
4/20/2011	36.32	35.25	31.52	31.45	29.79	26.99	25.64	38.44	36.32	26.15	20.34	18.61
4/21/2011	18.88	18.17	18.07	17.72	20.40	26.17	35.62	49.68	46.17	51.94	46.71	42.99
4/21/2011	42.87	42.42	40.44	36.35	34.12	28.73	27.21	38.74	39.17	29.44	22.94	20.68
4/22/2011	20.75	20.25	20.79	22.24	22.94	35.23	40.04	33.60	38.82	39.20	38.58	40.24
4/22/2011	41.69	42.44	33.45	32.45	30.83	28.06	27.35	41.20	29.16	26.52	21.56	19.31
4/23/2011	18.19	15.51	16.66	15.81	17.13	19.99	20.53	24.47	23.79	25.03	26.02	25.47
4/23/2011	25.46	25.20	24.07	23.84	23.90	23.52	23.44	31.15	25.39	22.66	18.74	17.28
4/24/2011	15.98	14.33	14.30	14.06	14.76	15.36	17.84	21.40	22.33	22.43	22.47	22.14
4/24/2011	22.29	22.36	22.36	22.32	22.39	22.59	23.33	34.61	23.94	20.40	17.48	15.55
4/25/2011	13.84	13.25	13.03	14.00	17.06	26.82	26.99	28.32	30.52	35.52	36.27	36.12
4/25/2011	33.95	32.84	29.08	27.38	26.61	25.26	24.94	33.38	30.65	23.46	18.89	16.63
4/26/2011	19.36	18.30	18.53	18.75	17.91	27.77	26.21	29.43	31.14	33.95	34.30	35.23
4/26/2011	35.14	35.09	33.76	28.32	27.26	25.03	24.93	35.04	35.92	26.22	21.09	19.10
4/27/2011	17.94	16.85	16.87	17.14	18.40	29.66	31.97	32.32	29.47	29.23	29.99	28.52
4/27/2011	27.53	27.09	24.49	23.78	22.67	22.07	21.52	27.22	25.48	20.73	18.43	15.84
4/28/2011	13.65	12.90	13.32	16.62	20.19	31.64	28.52	26.83	28.24	29.95	29.91	30.44
4/28/2011	29.58	30.22	27.61	26.51	25.23	24.24	23.92	31.72	35.83	22.52	18.95	17.96
4/29/2011	20.58	19.41	19.42	19.97	26.59	32.88	46.96	46.15	52.00	56.17	56.06	56.74
4/29/2011	60.08	57.24	58.60	60.52	46.89	39.56	33.80	42.58	46.16	31.64	28.43	23.98
4/30/2011	29.40	29.05	29.45	29.76	28.49	28.95	26.70	27.03	30.95	35.95	38.04	34.11
4/30/2011	34.82	34.00	33.52	32.30	34.38	30.94	29.95	38.55	40.61	27.70	28.19	27.05

Date	HOUR ENDING											
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
5/1/2011	17.53	16.63	16.48	15.40	15.48	16.51	18.36	19.88	21.52	22.62	23.96	23.37
5/1/2011	23.67	22.99	23.53	23.71	24.73	23.83	23.59	32.62	34.84	24.26	15.60	15.54
5/2/2011	14.65	13.91	16.13	16.59	19.08	23.69	29.02	32.42	30.98	36.62	37.93	38.12
5/2/2011	38.30	38.01	37.82	37.51	33.84	27.99	25.26	33.52	36.90	22.85	22.06	18.60
5/3/2011	21.31	22.48	20.87	20.46	20.90	26.64	33.29	37.52	36.90	44.43	47.20	51.25
5/3/2011	47.97	50.19	48.06	44.38	44.64	38.96	32.73	42.64	43.28	30.91	22.40	22.75
5/4/2011	22.40	21.30	21.17	21.90	25.95	29.78	31.85	32.21	34.99	41.26	42.75	46.52
5/4/2011	47.64	49.98	48.02	50.33	49.89	43.72	34.19	42.16	45.13	29.15	22.65	21.76
5/5/2011	24.33	24.39	24.75	24.23	26.97	29.20	35.09	36.91	37.65	39.49	41.09	41.37
5/5/2011	41.48	42.77	43.35	45.15	43.12	40.04	34.77	42.18	44.23	29.15	25.09	25.19
5/6/2011	24.95	23.25	24.16	24.12	25.19	26.26	30.43	33.01	32.76	35.75	35.01	34.89
5/6/2011	37.16	38.28	38.44	35.40	32.69	35.12	32.59	35.84	37.05	27.85	29.23	26.38
5/7/2011	28.24	27.80	26.47	25.88	25.83	29.00	30.91	36.14	36.54	37.18	38.42	39.60
5/7/2011	34.56	36.62	35.84	34.16	34.52	34.15	33.51	39.40	44.71	31.55	27.28	25.94
5/8/2011	27.02	25.87	24.85	24.59	25.31	28.49	34.81	29.47	29.38	29.28	30.43	32.42
5/8/2011	32.47	32.65	32.05	32.02	31.84	31.68	31.76	34.73	41.12	29.81	41.53	28.84
5/9/2011	22.24	22.34	22.29	23.06	24.80	27.44	34.97	35.56	35.39	39.08	38.32	39.32
5/9/2011	38.67	39.39	38.30	34.40	34.55	34.26	33.53	35.03	39.94	27.13	25.85	23.13
5/10/2011	13.38	13.07	13.14	13.40	16.08	18.76	25.55	27.45	28.32	30.06	31.08	30.98
5/10/2011	30.67	30.93	31.40	28.18	27.31	26.81	25.11	26.74	32.72	23.69	19.89	17.56
5/11/2011	15.43	14.91	14.67	14.69	15.46	20.02	25.50	28.03	33.11	33.78	33.85	34.88
5/11/2011	32.75	32.51	34.10	30.52	29.17	27.20	25.79	28.77	34.19	23.81	17.57	16.50
5/12/2011	16.76	16.54	16.19	16.31	19.43	21.56	29.82	34.17	39.95	40.04	41.30	41.53
5/12/2011	39.76	40.39	40.81	40.87	39.84	36.67	31.47	36.68	40.41	29.70	21.74	17.71
5/13/2011	16.99	16.58	16.93	17.24	18.13	20.56	26.26	30.60	36.42	37.29	39.38	39.81
5/13/2011	40.19	38.88	36.68	33.94	31.32	27.55	25.74	27.68	33.11	26.17	19.83	17.35
5/14/2011	17.78	16.11	16.58	16.76	16.88	17.66	18.88	22.89	24.73	26.37	27.89	26.04
5/14/2011	25.31	23.96	23.62	23.08	23.59	23.46	22.58	23.95	29.06	22.67	19.37	17.02
5/15/2011	16.35	15.72	15.18	14.98	15.44	15.76	16.91	19.25	20.33	20.57	21.27	21.64
5/15/2011	21.56	21.38	21.19	21.14	22.04	22.16	22.49	24.52	29.89	22.20	18.10	16.80
5/16/2011	16.36	15.72	15.53	16.14	16.66	19.61	25.64	31.09	34.77	38.26	38.20	38.26
5/16/2011	39.01	38.02	37.63	35.26	33.10	29.35	27.90	29.51	35.81	26.92	19.38	17.00
5/17/2011	16.49	16.11	15.46	15.45	16.13	20.44	24.90	30.76	33.87	36.65	37.18	37.09
5/17/2011	37.72	36.31	36.03	33.51	31.88	27.67	26.03	26.94	33.44	24.18	18.60	16.76
5/18/2011	17.11	16.32	16.16	15.65	16.99	20.13	21.68	24.54	27.59	29.18	30.00	30.19
5/18/2011	30.38	29.34	29.18	27.98	26.78	25.05	23.49	23.99	27.16	22.61	19.44	19.05
5/19/2011	17.74	16.83	16.74	17.39	17.56	21.88	26.19	26.03	30.22	31.65	32.50	34.54
5/19/2011	35.58	35.05	33.69	33.09	33.07	29.06	25.30	25.44	32.12	25.55	20.92	18.84
5/20/2011	18.26	17.29	17.08	17.38	18.41	21.32	26.59	28.85	33.18	35.83	38.39	37.19
5/20/2011	38.17	37.12	36.47	35.96	34.71	30.88	27.93	28.33	31.60	26.75	20.93	19.43
5/21/2011	23.06	20.13	20.81	21.21	24.15	24.57	28.40	33.18	39.51	41.60	25.31	26.38
5/21/2011	26.23	28.52	31.45	32.73	33.29	32.82	29.72	28.88	35.47	31.68	24.16	20.62
5/22/2011	21.43	22.59	21.87	20.95	27.98	21.92	28.99	33.90	38.89	41.43	28.79	32.22
5/22/2011	32.26	38.95	42.21	43.69	45.84	47.48	43.69	42.11	45.70	52.44	23.40	20.97
5/23/2011	19.68	17.31	18.24	18.65	18.86	22.60	27.79	26.77	31.05	37.48	43.41	51.37
5/23/2011	57.72	62.58	65.33	66.96	63.60	60.63	52.23	48.72	50.79	39.15	25.64	23.15
5/24/2011	21.51	19.32	16.54	15.90	16.62	20.85	25.40	31.50	35.62	42.01	44.96	51.63
5/24/2011	56.98	64.71	66.70	68.15	64.73	60.12	51.59	49.57	60.81	43.81	33.25	29.75
5/25/2011	18.56	17.11	16.17	15.99	16.09	18.23	22.73	28.24	32.39	43.38	40.35	47.30
5/25/2011	53.58	61.15	62.35	65.74	62.75	55.15	48.22	43.34	94.28	43.25	25.25	22.38
5/26/2011	16.08	14.90	16.31	15.87	16.20	17.77	19.45	22.96	27.83	32.22	35.86	40.24
5/26/2011	43.36	47.12	49.06	52.79	49.74	46.10	35.61	32.70	32.79	25.04	19.28	16.29
5/27/2011	20.02	18.78	18.43	18.55	19.44	20.63	23.52	25.75	26.85	30.52	34.17	31.48
5/27/2011	38.67	43.04	41.52	42.56	40.80	35.39	27.93	25.74	30.27	24.42	21.36	19.83
5/28/2011	20.61	19.45	18.30	18.33	18.26	16.77	20.07	21.62	23.27	25.78	29.66	31.92
5/28/2011	35.63	40.09	42.62	44.81	46.48	42.16	38.47	33.42	39.82	28.05	22.03	20.92
5/29/2011	18.21	17.73	16.23	15.25	15.81	13.84	20.00	21.04	22.16	25.94	31.58	35.25
5/29/2011	40.32	40.89	43.69	47.62	49.23	44.97	39.00	35.63	39.52	28.89	21.79	19.28
5/30/2011	18.44	16.00	14.70	15.41	15.97	11.62	16.09	22.50	23.92	25.57	29.55	30.36
5/30/2011	35.57	37.29	37.44	37.67	42.75	40.32	34.66	31.09	36.83	28.48	19.37	18.44
5/31/2011	19.84	17.95	17.41	17.69	18.41	21.13	29.98	32.36	34.61	47.82	56.08	60.77
5/31/2011	64.81	64.28	65.41	70.15	65.39	59.95	57.84	53.92	56.55	37.80	21.93	21.57

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
6/1/2011	19.05	18.69	17.87	18.11	18.64	18.75	21.99	25.94	30.77	35.48	44.26	44.37
6/1/2011	48.68	52.81	54.84	54.28	54.10	45.53	42.78	31.99	43.85	30.95	24.26	20.71
6/2/2011	19.95	18.86	18.20	18.20	18.70	19.39	23.79	26.33	28.80	34.57	39.66	36.34
6/2/2011	39.67	41.98	41.44	42.72	40.87	37.29	33.85	30.07	34.69	25.59	19.05	19.22
6/3/2011	19.05	18.27	17.68	17.60	18.12	18.31	21.22	22.55	27.09	32.99	37.70	38.79
6/3/2011	42.22	42.48	41.87	41.25	43.46	36.09	33.30	30.58	34.31	25.80	21.12	19.87
6/4/2011	20.06	18.33	17.66	17.29	17.50	17.51	18.99	21.10	23.28	30.42	32.88	34.83
6/4/2011	35.07	36.08	37.30	36.71	36.80	34.63	33.33	28.87	32.74	26.50	21.54	19.39
6/5/2011	19.33	18.80	18.57	18.48	17.46	16.63	17.15	18.94	19.60	20.69	21.69	23.01
6/5/2011	22.45	22.78	23.81	24.21	24.17	22.83	21.84	21.02	24.63	19.95	18.11	17.11
6/6/2011	15.66	13.56	13.05	13.64	15.78	18.70	22.26	26.14	30.85	36.96	39.27	39.02
6/6/2011	40.79	40.12	38.84	41.33	36.28	35.12	32.65	30.10	36.83	25.11	20.44	19.15
6/7/2011	19.43	19.08	18.72	18.72	19.95	21.49	23.73	26.41	30.05	33.55	35.00	36.17
6/7/2011	35.99	34.96	35.07	35.23	35.09	32.98	30.54	29.82	31.78	25.75	22.24	20.72
6/8/2011	20.02	18.27	17.90	18.02	18.99	20.21	23.14	26.13	26.60	31.16	35.01	34.77
6/8/2011	34.03	36.39	37.49	37.55	36.32	33.42	31.56	29.77	33.71	27.52	21.32	19.70
6/9/2011	19.92	18.21	17.80	18.71	19.87	21.30	23.57	28.51	31.54	37.94	38.20	39.04
6/9/2011	39.73	41.74	42.02	39.97	40.61	37.93	37.18	34.44	37.24	27.88	21.58	20.70
6/10/2011	22.11	20.96	20.15	20.61	21.62	21.16	23.57	25.86	30.26	34.01	38.02	40.76
6/10/2011	41.34	45.59	44.19	47.97	43.58	42.42	38.74	37.65	38.68	34.30	25.13	23.06
6/11/2011	21.18	20.16	19.49	19.41	19.41	19.39	19.94	23.55	30.57	31.95	39.01	39.77
6/11/2011	43.11	44.51	47.69	51.20	48.97	48.06	43.38	39.49	40.82	36.36	26.05	22.07
6/12/2011	23.52	21.19	20.76	19.70	19.09	19.15	20.79	22.55	24.40	29.95	35.38	38.60
6/12/2011	42.49	42.60	49.67	46.74	46.72	44.41	39.97	38.47	40.02	33.47	27.04	23.13
6/13/2011	17.10	15.16	14.43	14.50	15.96	17.58	24.03	27.01	32.26	40.88	44.24	45.37
6/13/2011	47.89	50.98	47.32	46.31	44.35	39.27	37.99	40.56	40.56	29.10	22.95	17.29
6/14/2011	16.73	15.35	14.88	14.53	15.42	17.99	22.09	24.33	26.64	33.89	35.97	38.24
6/14/2011	38.84	38.57	40.49	41.60	40.19	37.62	36.36	36.96	40.03	31.30	24.92	17.53
6/15/2011	21.05	17.21	17.58	17.68	19.95	20.58	25.74	29.13	30.00	36.51	40.69	44.75
6/15/2011	50.09	53.57	54.15	56.68	54.51	47.17	41.79	38.62	40.17	34.01	26.82	20.46
6/16/2011	21.49	20.11	19.84	20.08	21.12	20.36	23.54	26.53	29.00	35.81	41.22	42.05
6/16/2011	47.60	53.82	54.47	56.39	54.70	48.75	40.83	39.39	40.59	33.71	25.80	22.16
6/17/2011	20.72	18.50	17.47	16.16	17.58	18.96	20.36	22.66	25.94	34.27	41.31	44.59
6/17/2011	50.15	58.38	63.11	68.09	62.27	55.15	45.64	43.36	43.54	35.01	30.30	25.47
6/18/2011	21.21	20.46	20.36	19.92	19.22	18.85	20.57	24.04	30.80	36.31	48.90	51.29
6/18/2011	52.63	57.12	58.70	61.65	57.82	54.55	47.55	41.26	40.75	33.54	25.84	18.48
6/19/2011	26.53	24.44	23.79	22.66	21.54	13.37	16.26	20.26	23.12	26.31	31.55	34.21
6/19/2011	40.12	42.62	46.19	48.09	49.88	43.99	42.23	38.57	40.91	31.39	23.65	23.46
6/20/2011	20.45	19.74	18.38	20.43	21.28	23.09	22.96	29.69	31.85	37.76	46.11	49.87
6/20/2011	57.18	65.73	67.64	73.78	68.34	59.59	51.51	46.94	46.09	39.41	29.39	25.00
6/21/2011	20.74	19.71	19.18	19.00	19.55	20.06	24.42	29.28	34.97	44.07	53.81	57.94
6/21/2011	63.86	73.38	76.55	84.16	76.83	71.44	61.08	56.34	58.58	45.26	34.74	28.70
6/22/2011	20.82	19.36	18.86	18.67	18.88	19.70	23.39	30.10	35.43	45.18	53.36	57.86
6/22/2011	67.16	73.63	77.46	83.84	76.62	68.68	58.29	54.60	53.47	41.53	29.78	23.99
6/23/2011	20.52	19.28	19.01	18.88	18.89	19.49	27.45	32.64	35.93	42.59	48.26	51.33
6/23/2011	59.48	61.90	67.51	72.07	65.31	58.59	51.75	43.06	43.49	36.19	23.05	18.06
6/24/2011	17.95	16.11	15.28	15.35	15.65	17.37	21.35	22.25	26.11	31.89	36.53	40.29
6/24/2011	42.99	48.24	51.36	54.73	50.64	47.27	39.93	34.49	36.23	29.80	22.40	16.81
6/25/2011	25.80	23.77	21.11	21.62	20.78	20.10	21.13	24.41	30.33	30.21	35.39	42.24
6/25/2011	46.62	50.18	54.76	63.66	60.68	57.31	49.19	42.46	42.77	41.17	31.94	19.86
6/26/2011	31.93	28.32	27.31	27.01	26.93	25.72	28.60	27.72	30.22	27.03	34.24	41.64
6/26/2011	47.68	49.69	55.04	58.45	58.72	52.88	50.12	43.78	46.10	43.41	29.65	28.42
6/27/2011	29.86	29.36	28.42	28.58	29.45	30.31	33.69	33.58	36.84	39.89	51.89	55.83
6/27/2011	60.93	66.72	71.69	72.79	68.34	55.81	44.11	38.51	38.79	34.43	21.56	14.44
6/28/2011	15.32	13.85	12.52	12.53	15.04	13.12	16.19	20.04	22.67	26.16	32.86	33.31
6/28/2011	37.43	39.39	39.63	39.42	38.44	33.39	32.56	28.88	28.58	23.83	17.19	13.78
6/29/2011	14.06	13.43	12.72	12.51	15.60	17.64	33.02	23.89	24.89	28.84	31.25	31.59
6/29/2011	30.66	32.98	33.89	34.79	35.72	33.42	30.20	25.65	26.45	22.92	24.65	19.82
6/30/2011	11.84	11.53	10.56	10.70	9.83	11.70	17.63	19.38	20.54	22.92	24.36	24.96
6/30/2011	28.58	32.36	32.97	33.17	32.92	31.68	26.08	22.66	23.55	20.98	15.59	11.75

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
7/1/2011	17.66	17.11	16.19	15.86	16.85	18.06	18.18	19.53	22.45	24.61	26.95	27.27
7/1/2011	31.35	36.08	36.47	37.90	36.71	35.06	28.65	24.42	24.73	23.07	19.98	20.27
7/2/2011	18.16	14.35	12.73	13.80	13.48	11.93	21.30	21.72	22.41	23.53	28.86	32.17
7/2/2011	38.26	42.92	49.57	55.62	54.17	49.48	41.20	35.22	36.24	32.09	17.25	17.19
7/3/2011	11.71	8.87	7.91	9.08	8.70	6.18	5.73	19.42	20.85	23.86	26.04	32.63
7/3/2011	35.29	43.91	47.00	49.71	48.94	48.73	46.00	37.60	34.44	33.41	18.18	18.89
7/4/2011	19.35	13.31	13.19	11.89	12.01	10.89	12.37	19.64	20.30	23.16	26.18	28.53
7/4/2011	36.25	35.84	45.34	47.05	50.54	45.09	39.11	33.52	30.55	28.43	19.89	16.88
7/5/2011	20.44	18.74	18.03	18.22	19.21	20.00	21.86	31.97	36.85	46.97	54.73	57.45
7/5/2011	61.71	69.91	71.39	80.03	77.79	70.74	63.16	55.98	55.03	45.44	27.90	24.17
7/6/2011	22.45	21.01	18.86	19.70	19.78	20.51	21.40	33.20	39.83	49.00	53.01	61.41
7/6/2011	67.83	77.51	82.45	85.63	82.80	73.89	64.99	52.07	50.99	46.52	27.77	24.49
7/7/2011	23.52	20.80	20.20	20.32	20.45	20.70	22.50	29.37	35.70	47.02	51.86	53.16
7/7/2011	58.35	63.20	65.03	68.28	63.25	57.98	53.26	46.33	45.34	32.77	24.55	22.56
7/8/2011	22.63	19.79	19.39	18.99	19.01	18.36	19.13	24.24	27.75	35.63	37.34	41.14
7/8/2011	45.75	46.31	48.65	50.86	46.72	42.92	36.54	30.15	32.38	27.08	22.93	21.23
7/9/2011	24.02	21.20	19.40	19.07	19.58	19.54	20.80	23.18	25.52	29.99	34.59	39.50
7/9/2011	41.93	44.30	48.55	53.59	51.02	47.54	41.83	34.76	38.03	32.40	25.77	23.72
7/10/2011	23.13	22.98	19.31	17.46	16.98	14.42	17.12	24.06	25.91	27.83	31.22	34.75
7/10/2011	37.78	39.21	44.01	45.71	47.47	43.88	41.12	35.68	40.19	34.15	24.09	23.83
7/11/2011	26.20	26.09	25.90	25.24	24.84	25.33	25.05	30.01	30.50	38.85	44.73	49.30
7/11/2011	54.33	58.39	59.29	58.66	54.17	50.18	43.45	38.56	41.32	33.38	25.39	22.98
7/12/2011	20.09	19.08	18.57	18.40	18.50	20.07	21.26	23.30	26.55	32.08	36.23	39.37
7/12/2011	44.72	47.72	49.43	51.52	48.34	43.06	35.77	33.05	36.28	29.85	24.20	21.95
7/13/2011	18.71	17.13	16.06	15.28	16.62	16.99	18.95	21.74	25.14	34.91	40.24	46.70
7/13/2011	49.10	58.15	58.76	64.99	61.57	56.02	48.28	45.30	46.00	34.90	27.04	22.16
7/14/2011	21.45	20.84	18.46	17.04	18.98	18.73	21.00	26.63	33.14	42.46	50.34	53.60
7/14/2011	61.60	68.39	71.20	74.54	69.81	63.88	55.78	51.00	51.30	40.39	25.92	22.15
7/15/2011	21.52	20.45	17.70	16.40	16.54	18.41	20.53	23.80	26.56	41.56	46.08	50.66
7/15/2011	56.96	70.67	67.24	67.16	66.08	56.20	48.12	43.25	43.26	31.95	25.19	22.56
7/16/2011	20.03	17.34	14.89	13.90	14.62	11.77	18.12	20.98	24.79	32.89	38.42	42.16
7/16/2011	46.54	53.11	57.99	61.50	58.91	55.06	48.06	39.17	43.56	33.88	24.23	21.78
7/17/2011	21.63	20.58	18.06	15.68	14.83	14.27	16.50	20.33	24.92	28.62	32.71	40.54
7/17/2011	51.94	58.00	66.11	69.95	66.98	61.11	53.23	44.03	50.41	39.22	23.24	21.94
7/18/2011	18.69	19.07	18.74	18.88	15.49	20.20	17.75	23.41	28.23	33.09	38.20	44.74
7/18/2011	51.44	53.64	55.06	61.05	58.58	50.81	45.26	38.79	40.31	30.70	24.56	19.31
7/19/2011	21.31	17.15	17.41	16.59	19.69	20.11	23.16	29.71	31.06	39.09	44.67	49.69
7/19/2011	55.87	61.85	64.56	69.16	68.63	60.63	52.23	47.25	50.63	39.20	24.36	17.74
7/20/2011	15.97	13.69	13.13	12.81	14.61	17.22	21.78	31.51	34.05	42.75	44.98	51.32
7/20/2011	56.61	61.93	66.79	67.16	69.24	56.22	49.73	44.54	47.01	35.97	24.38	18.15
7/21/2011	20.45	19.03	17.72	16.85	18.27	19.21	22.93	26.89	32.41	36.91	43.58	48.01
7/21/2011	52.04	54.09	60.06	67.63	60.42	53.43	50.59	45.36	48.55	38.35	27.59	21.66
7/22/2011	24.40	22.13	22.02	21.38	22.04	22.48	30.66	35.14	41.94	51.58	61.40	63.95
7/22/2011	72.09	76.61	83.89	86.01	75.68	68.05	63.08	55.81	58.80	46.08	31.36	22.95
7/23/2011	28.06	25.18	23.02	21.71	21.88	21.47	22.65	26.85	36.95	46.26	52.72	55.37
7/23/2011	60.88	63.92	68.38	79.14	72.21	61.86	53.80	47.21	47.11	37.80	25.39	24.39
7/24/2011	22.82	21.43	18.83	16.95	16.34	15.35	15.67	20.02	21.89	23.90	29.81	34.61
7/24/2011	35.88	39.38	42.98	43.30	42.87	39.67	39.72	33.24	36.91	30.07	24.54	21.91
7/25/2011	19.67	18.41	17.06	17.37	19.65	21.28	21.37	23.53	27.05	29.83	36.18	41.11
7/25/2011	48.66	50.90	57.12	63.91	59.68	51.33	44.68	38.83	39.50	29.99	23.69	19.95
7/26/2011	20.15	18.21	17.02	16.98	18.44	20.98	20.96	23.46	27.98	31.44	38.72	43.50
7/26/2011	49.08	53.63	59.55	69.35	60.80	54.28	49.49	42.54	45.10	34.83	26.26	24.35
7/27/2011	33.76	29.05	29.03	29.00	30.60	32.74	29.74	31.17	35.87	42.90	51.08	57.05
7/27/2011	61.93	64.48	70.30	78.32	69.92	63.95	54.78	50.68	53.12	39.94	44.05	36.28
7/28/2011	25.42	24.39	22.53	22.66	24.53	24.96	25.23	26.33	29.47	35.85	43.10	46.89
7/28/2011	51.83	53.67	59.64	62.47	56.52	50.93	45.49	39.32	38.87	29.42	25.82	22.79
7/29/2011	20.63	19.65	16.84	15.65	17.04	20.36	21.70	26.70	29.42	34.78	40.85	45.68
7/29/2011	50.60	53.07	57.50	60.18	57.24	51.45	45.48	38.72	38.73	33.13	24.16	18.27
7/30/2011	32.32	31.13	34.01	31.89	29.21	27.27	19.53	23.19	26.58	30.66	35.39	40.10
7/30/2011	41.47	48.04	50.94	61.18	56.44	47.91	41.61	37.11	40.68	31.34	23.18	18.77
7/31/2011	16.25	15.25	13.56	12.65	13.22	11.62	13.31	18.22	20.59	24.75	29.36	32.15
7/31/2011	40.03	43.32	44.34	51.13	52.34	46.13	39.43	34.97	37.56	30.30	23.14	20.28

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
8/1/2011	23.08	19.75	18.66	18.23	18.19	20.93	23.57	29.45	33.84	40.92	49.42	56.99
8/1/2011	63.79	69.54	76.14	87.59	78.99	65.69	58.72	55.76	59.16	44.11	33.73	28.65
8/2/2011	23.45	20.59	19.90	19.23	19.12	21.36	27.90	34.10	39.74	50.83	59.65	64.88
8/2/2011	74.41	77.99	87.28	93.32	88.27	73.86	67.95	61.77	63.79	49.76	38.45	30.97
8/3/2011	25.35	21.33	20.15	19.11	19.86	21.90	24.85	37.25	40.55	55.13	61.22	69.61
8/3/2011	74.74	78.60	91.52	94.67	81.93	73.71	67.67	62.29	64.67	47.79	32.79	27.04
8/4/2011	25.48	21.09	16.19	15.76	17.63	22.87	24.16	35.60	37.72	47.71	60.52	65.25
8/4/2011	72.31	74.13	83.75	84.39	77.49	70.74	62.46	58.09	58.21	42.88	30.01	24.87
8/5/2011	17.80	15.68	13.26	13.05	12.98	15.19	19.99	26.03	33.35	36.31	40.69	46.76
8/5/2011	53.78	55.39	59.19	60.35	54.39	46.70	40.15	36.89	36.60	30.83	27.60	22.36
8/6/2011	16.22	14.25	12.67	11.33	11.34	11.24	17.28	21.82	24.48	27.49	30.89	33.93
8/6/2011	35.96	40.30	44.03	49.01	48.45	45.97	39.55	35.73	34.32	28.61	23.23	20.26
8/7/2011	20.47	19.02	16.48	12.90	13.79	12.62	13.15	23.45	24.93	28.57	34.72	39.29
8/7/2011	47.05	52.87	54.59	61.44	69.19	63.48	52.99	53.90	60.40	44.75	31.21	26.55
8/8/2011	23.28	20.37	18.62	18.57	18.50	20.61	24.97	30.07	34.93	44.92	52.64	56.31
8/8/2011	63.20	69.68	75.60	84.05	80.08	69.43	62.55	57.87	59.36	44.82	32.77	27.76
8/9/2011	26.11	24.44	23.20	22.23	21.65	24.28	26.60	32.02	38.15	49.97	55.81	62.88
8/9/2011	71.37	76.24	85.03	87.96	81.78	73.32	63.71	60.40	62.78	48.54	39.79	30.16
8/10/2011	25.91	23.04	21.29	21.00	21.96	24.18	25.18	34.99	43.39	52.73	59.85	66.17
8/10/2011	75.39	82.51	86.20	88.77	81.30	75.26	65.59	63.20	64.97	48.25	41.12	29.08
8/11/2011	25.63	22.62	21.18	20.74	22.05	26.32	27.84	39.02	48.38	54.33	64.72	73.13
8/11/2011	81.85	86.70	91.30	109.30	90.72	82.73	68.99	67.59	66.92	50.54	39.44	34.90
8/12/2011	29.00	24.93	24.31	24.43	24.75	26.20	26.62	33.48	39.91	49.02	55.25	62.47
8/12/2011	69.76	73.87	78.45	87.43	77.42	69.84	62.13	59.02	57.05	45.33	34.48	30.24
8/13/2011	31.17	27.85	24.86	23.91	23.77	24.60	26.02	28.17	33.35	40.36	49.88	53.85
8/13/2011	56.93	62.67	68.17	76.13	71.59	63.14	55.05	51.70	51.34	37.06	29.01	27.31
8/14/2011	26.22	24.69	24.18	22.87	21.81	21.96	22.43	26.88	28.15	31.31	37.32	38.61
8/14/2011	47.00	49.33	57.74	61.19	60.55	55.28	44.45	43.18	47.53	33.01	26.49	25.09
8/15/2011	20.62	15.90	10.21	10.62	13.88	16.77	21.34	27.00	31.25	33.93	42.39	45.34
8/15/2011	52.71	58.20	62.33	63.66	59.46	53.41	45.89	43.94	42.91	30.15	25.36	23.59
8/16/2011	18.60	13.44	12.17	14.66	16.15	17.63	22.07	24.83	30.02	32.05	35.71	39.95
8/16/2011	43.42	49.41	54.07	55.32	54.56	49.60	40.76	34.18	38.70	27.73	25.22	21.23
8/17/2011	22.73	20.97	19.57	19.89	19.81	21.20	24.90	26.40	31.19	32.53	37.30	42.74
8/17/2011	50.07	52.86	54.88	58.67	56.25	50.72	43.30	44.24	43.58	30.79	27.27	23.96
8/18/2011	26.06	24.23	22.98	23.50	24.55	24.78	26.19	28.19	31.15	37.44	45.12	50.50
8/18/2011	55.47	61.71	67.52	71.77	67.82	58.99	50.55	50.46	48.67	34.80	30.35	25.51
8/19/2011	26.46	25.05	23.67	23.66	24.68	25.58	24.33	29.71	30.98	42.05	53.81	57.21
8/19/2011	67.77	70.47	78.11	82.91	66.08	60.90	50.51	54.07	50.40	35.44	28.45	27.12
8/20/2011	26.33	24.14	23.18	22.09	21.31	22.21	23.44	26.42	31.34	37.60	43.47	49.30
8/20/2011	47.37	50.63	50.15	56.23	56.97	51.03	44.51	44.50	42.31	32.92	28.25	25.86
8/21/2011	23.64	22.64	20.75	18.89	18.26	18.94	19.18	21.90	24.16	26.12	28.99	33.18
8/21/2011	33.99	38.23	41.42	47.01	46.53	43.97	38.04	41.11	40.54	29.83	25.01	22.97
8/22/2011	22.42	20.63	19.91	20.69	22.82	25.06	23.79	24.67	29.14	31.35	36.99	41.86
8/22/2011	45.56	47.52	52.44	55.81	54.01	46.10	42.56	43.52	41.22	29.45	26.00	23.26
8/23/2011	28.15	24.95	23.73	23.71	24.80	29.48	27.18	23.97	26.18	30.02	31.13	35.51
8/23/2011	38.88	41.68	43.81	47.32	46.21	39.05	35.03	40.54	37.10	28.95	31.65	28.19
8/24/2011	24.84	22.28	22.16	22.04	23.95	25.41	24.55	25.20	26.69	30.34	34.54	36.76
8/24/2011	39.91	39.56	42.46	42.19	39.01	38.37	31.89	35.98	33.01	26.02	24.89	22.18
8/25/2011	23.55	19.01	18.03	20.77	21.55	28.30	23.80	23.64	23.97	24.98	25.20	26.52
8/25/2011	29.11	28.92	29.63	29.91	29.27	28.03	25.24	28.20	25.49	22.67	22.32	20.92
8/26/2011	19.13	14.21	12.66	13.72	20.04	26.22	23.29	23.80	25.25	26.77	27.21	27.93
8/26/2011	30.41	32.48	33.75	35.78	32.53	30.16	26.83	29.84	27.50	23.66	23.99	21.24
8/27/2011	21.85	15.82	14.71	13.14	17.44	20.33	21.68	26.32	28.25	30.48	31.46	33.76
8/27/2011	38.28	42.09	42.09	47.21	46.31	42.34	34.80	40.19	41.71	30.84	25.53	24.47
8/28/2011	24.94	18.45	15.21	15.66	13.98	16.09	19.49	26.27	27.31	29.23	32.18	36.33
8/28/2011	38.60	41.58	48.86	55.00	57.21	50.94	41.50	43.79	42.93	30.55	25.98	24.48
8/29/2011	27.02	24.52	23.57	23.57	24.77	27.97	27.70	26.93	30.86	36.46	44.04	50.38
8/29/2011	55.39	59.96	66.19	74.01	65.54	55.93	47.07	52.04	48.36	33.14	28.42	26.11
8/30/2011	24.76	21.86	20.83	21.23	22.05	26.92	25.42	26.88	28.81	39.57	48.83	55.55
8/30/2011	53.73	54.68	61.41	66.43	62.02	52.81	47.36	47.11	44.17	32.79	27.15	25.90
8/31/2011	31.24	30.50	28.23	27.76	29.05	35.16	31.02	25.86	31.04	36.38	42.61	48.95
8/31/2011	59.33	61.10	70.47	80.44	66.03	57.23	51.91	54.79	46.49	37.15	33.43	31.14

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
9/1/2011	32.61	31.73	30.79	30.97	32.69	35.65	32.50	33.07	34.94	37.21	42.91	45.40
9/1/2011	52.66	61.72	70.43	70.15	59.93	48.29	44.64	50.10	42.50	34.09	35.51	33.46
9/2/2011	31.87	28.95	29.34	30.13	32.26	36.46	37.26	36.73	42.26	47.74	49.26	50.06
9/2/2011	47.28	48.45	48.90	46.75	47.06	37.66	37.01	41.98	34.39	29.96	31.05	30.99
9/3/2011	30.07	27.79	26.62	26.19	27.38	30.75	31.04	35.39	36.42	33.95	34.53	34.26
9/3/2011	33.97	33.39	33.04	32.30	33.50	33.65	32.21	35.93	34.68	29.35	30.15	27.47
9/4/2011	13.40	11.88	8.66	8.65	10.80	14.08	17.60	26.76	31.39	30.61	30.93	31.32
9/4/2011	31.17	32.56	32.51	33.68	36.14	36.00	36.25	36.50	35.20	29.46	26.44	25.00
9/5/2011	6.87	5.61	1.44	1.94	2.06	3.64	12.28	27.47	33.69	30.84	33.36	36.38
9/5/2011	40.16	38.58	39.57	44.01	46.18	43.62	42.94	46.24	43.20	31.11	27.18	28.12
9/6/2011	22.21	21.49	20.16	21.13	31.93	43.05	46.82	42.83	40.77	43.61	46.36	49.53
9/6/2011	57.21	43.92	50.42	51.24	49.64	43.74	40.83	45.96	38.84	31.07	28.18	22.00
9/7/2011	16.86	14.01	11.76	14.49	21.28	32.82	32.40	30.50	32.90	31.67	32.75	34.68
9/7/2011	35.47	35.53	38.77	37.65	36.51	33.76	31.39	37.21	31.15	29.21	23.79	19.74
9/8/2011	5.80	3.06	1.55	3.90	23.44	34.79	31.57	32.45	32.79	33.96	35.39	36.78
9/8/2011	38.54	38.11	39.65	39.54	38.80	36.22	35.39	38.45	36.99	31.46	23.97	21.98
9/9/2011	23.08	21.90	18.99	21.85	31.67	47.11	31.81	31.48	33.98	37.27	38.22	41.23
9/9/2011	45.43	45.37	46.76	45.95	40.40	35.48	33.27	39.88	32.84	30.80	27.16	27.30
9/10/2011	19.95	17.40	13.58	18.22	20.42	25.18	27.63	27.49	32.30	34.02	34.80	33.58
9/10/2011	32.77	35.59	33.62	33.13	33.02	32.06	31.71	40.79	31.40	28.62	22.23	15.61
9/11/2011	16.18	14.14	10.10	8.88	9.04	12.36	16.27	23.62	26.91	27.63	28.36	28.36
9/11/2011	28.66	28.83	29.57	30.98	30.93	30.25	30.93	46.02	31.96	26.82	20.18	18.09
9/12/2011	17.67	15.91	12.28	15.60	23.31	32.81	28.50	31.44	34.22	35.83	40.67	43.31
9/12/2011	46.39	47.48	52.33	50.11	47.79	40.03	40.13	49.96	37.04	31.09	25.98	23.71
9/13/2011	22.55	19.80	17.96	19.88	24.95	37.51	32.54	32.05	36.25	38.01	41.66	45.29
9/13/2011	46.90	48.00	52.51	52.57	47.15	39.20	39.20	50.09	37.24	30.08	26.00	24.18
9/14/2011	21.75	19.96	17.15	19.77	24.15	37.56	30.52	29.84	31.46	34.68	36.40	37.62
9/14/2011	43.29	45.00	48.91	49.75	44.37	40.73	40.61	48.24	35.52	29.10	23.98	21.34
9/15/2011	22.52	19.98	18.23	20.18	25.56	38.90	34.81	33.47	37.82	41.49	43.01	48.12
9/15/2011	48.80	48.02	48.12	48.09	42.56	36.59	36.21	45.42	35.87	29.25	22.81	21.79
9/16/2011	31.39	31.39	29.25	30.05	33.13	44.20	43.96	32.88	35.61	38.77	41.46	45.00
9/16/2011	46.15	47.57	49.00	49.25	40.15	34.31	33.65	38.50	34.36	30.14	24.11	22.51
9/17/2011	16.23	14.86	13.87	15.18	16.39	21.86	23.64	26.48	28.77	31.28	32.48	32.06
9/17/2011	32.99	33.08	33.39	33.85	35.56	34.53	33.33	38.35	30.94	26.53	21.28	17.35
9/18/2011	13.31	9.84	10.03	9.86	11.21	13.48	17.64	21.98	22.75	26.50	27.56	28.40
9/18/2011	28.93	29.05	29.56	28.88	30.35	30.65	29.22	40.77	28.99	27.02	20.53	18.27
9/19/2011	12.62	12.98	9.08	9.17	10.43	20.99	24.11	25.11	28.26	34.21	37.01	37.59
9/19/2011	38.55	38.45	39.74	41.64	40.02	38.41	37.46	38.98	32.54	25.58	23.53	21.05
9/20/2011	20.13	14.96	10.58	12.86	16.23	23.31	32.78	32.19	33.55	41.73	46.74	47.79
9/20/2011	50.29	57.58	63.41	69.39	64.23	56.78	53.52	55.42	49.90	38.30	27.83	22.98
9/21/2011	24.75	23.93	23.38	24.02	24.40	32.76	36.28	35.24	37.45	45.33	50.01	61.06
9/21/2011	72.74	73.71	76.97	81.27	67.79	56.46	56.58	61.91	41.25	34.60	29.75	27.78
9/22/2011	29.33	27.17	24.60	26.98	29.35	37.43	38.57	38.67	44.33	38.98	40.91	52.44
9/22/2011	66.38	73.75	78.19	86.95	94.89	68.36	63.10	68.29	47.00	34.37	27.34	29.42
9/23/2011	26.70	24.07	23.38	23.20	24.39	35.38	34.08	35.87	40.80	36.39	39.80	40.13
9/23/2011	42.58	43.70	41.52	41.30	41.53	37.17	36.62	37.65	32.80	28.78	25.50	22.82
9/24/2011	22.06	19.48	16.58	16.96	18.49	24.83	26.21	29.37	30.80	32.83	33.16	33.19
9/24/2011	32.42	32.98	32.59	34.36	33.57	33.38	35.92	38.10	31.75	28.47	23.79	20.25
9/25/2011	18.16	17.34	14.74	15.22	17.09	20.23	19.85	23.89	28.27	29.20	28.47	28.21
9/25/2011	27.85	27.77	28.36	29.13	29.59	30.19	37.44	42.58	31.84	29.19	24.41	22.49
9/26/2011	16.19	16.64	14.10	15.18	19.12	31.41	33.52	32.35	35.39	34.83	37.25	36.65
9/26/2011	37.26	37.49	38.45	37.97	36.40	34.47	37.44	43.73	32.51	29.16	23.23	21.01
9/27/2011	14.90	13.02	11.89	13.85	14.15	29.90	32.77	29.26	30.55	33.36	38.22	41.55
9/27/2011	41.17	40.57	38.35	36.96	34.62	33.56	42.67	40.86	33.78	29.42	23.72	18.96
9/28/2011	13.46	10.14	10.65	11.02	15.42	34.20	38.39	31.27	32.67	38.68	39.82	40.41
9/28/2011	41.71	41.64	39.10	42.28	32.08	32.00	38.21	39.87	32.91	28.99	23.50	20.85
9/29/2011	19.62	13.53	13.77	13.85	22.07	33.81	34.95	27.96	30.61	33.99	39.61	40.49
9/29/2011	41.30	41.40	40.02	39.19	35.87	34.52	46.48	45.75	35.91	29.59	24.47	21.04
9/30/2011	21.69	19.30	19.59	20.89	27.46	33.27	37.40	33.79	41.75	42.81	42.50	43.68
9/30/2011	40.97	40.88	41.07	37.83	34.15	32.67	43.99	38.23	30.78	29.25	23.32	24.31

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
10/1/2011	23.17	23.30	23.09	23.71	24.16	25.39	26.25	29.73	30.59	36.18	34.29	32.69
10/1/2011	30.80	29.26	30.19	30.22	30.60	28.08	38.80	33.88	29.01	28.31	23.16	20.90
10/2/2011	23.32	20.83	20.03	19.76	20.64	23.54	26.23	26.64	28.22	28.81	29.00	27.45
10/2/2011	27.25	27.27	27.26	27.57	27.95	29.26	44.17	41.09	32.60	29.02	25.09	25.33
10/3/2011	28.93	22.04	22.59	14.10	26.00	37.91	52.36	37.49	43.04	44.88	44.02	40.41
10/3/2011	37.99	37.01	31.96	31.47	31.59	31.15	53.74	44.25	35.60	31.04	25.98	24.78
10/4/2011	28.38	29.49	30.20	28.22	31.68	40.69	50.33	43.60	49.46	47.40	45.77	43.29
10/4/2011	44.20	43.93	40.76	39.56	36.99	37.53	50.04	44.49	38.34	33.48	26.66	29.50
10/5/2011	27.52	26.57	28.63	29.10	30.49	36.33	40.55	33.87	32.90	36.61	39.45	39.56
10/5/2011	40.41	39.33	32.29	32.40	34.13	35.13	45.78	39.63	32.82	31.43	27.04	26.72
10/6/2011	24.05	23.98	21.65	26.58	26.95	34.86	35.57	31.99	33.44	37.47	38.96	38.05
10/6/2011	38.45	39.27	35.94	35.21	33.72	34.69	46.01	43.31	33.19	31.20	27.79	26.99
10/7/2011	29.96	27.75	28.84	30.02	31.38	39.42	36.28	28.68	29.60	31.91	34.39	35.62
10/7/2011	36.74	39.27	38.49	35.57	35.12	31.66	40.36	38.58	31.14	28.75	26.16	25.16
10/8/2011	18.70	16.90	15.47	15.50	18.91	23.91	27.88	29.19	31.78	37.63	37.19	35.43
10/8/2011	36.16	36.37	36.21	36.23	36.66	37.51	46.12	41.26	33.13	30.22	23.50	22.14
10/9/2011	20.53	17.91	18.15	17.86	18.45	21.90	24.36	25.06	26.84	27.59	29.31	29.91
10/9/2011	31.49	32.24	34.43	35.01	36.83	37.33	51.04	49.55	36.78	29.55	24.90	23.91
10/10/2011	20.63	19.31	21.08	21.69	21.49	32.69	36.45	30.60	33.50	35.72	41.65	41.31
10/10/2011	43.32	43.79	45.14	41.26	41.25	41.23	44.79	41.35	34.80	28.62	26.22	24.28
10/11/2011	22.07	21.40	21.60	21.91	22.60	26.95	33.00	32.28	32.63	36.53	38.33	43.02
10/11/2011	43.28	43.59	43.27	41.12	37.66	36.97	42.35	41.92	33.66	29.90	25.74	24.02
10/12/2011	21.16	23.04	22.56	23.04	23.24	31.32	39.76	33.57	36.63	37.62	38.88	39.00
10/12/2011	39.86	39.47	38.78	37.87	36.39	36.03	51.12	43.81	36.68	31.20	25.97	26.42
10/13/2011	23.05	22.31	22.60	23.97	25.96	33.97	40.86	34.96	34.79	36.36	35.65	35.26
10/13/2011	34.59	33.13	30.26	30.60	30.06	30.62	38.19	33.88	30.16	27.97	24.42	22.73
10/14/2011	22.05	21.13	21.68	19.97	23.28	30.58	39.68	38.82	39.66	42.27	45.27	42.62
10/14/2011	39.67	38.52	35.42	34.29	32.96	33.75	42.16	37.19	37.70	35.56	26.17	27.83
10/15/2011	27.06	22.70	19.81	21.10	21.35	25.70	30.31	30.83	32.03	32.40	31.11	29.22
10/15/2011	28.41	28.11	27.89	27.97	27.87	29.25	42.89	31.50	27.41	26.13	20.88	18.42
10/16/2011	20.15	20.00	18.95	18.83	18.79	20.00	25.26	27.26	27.94	28.37	28.89	29.31
10/16/2011	29.14	28.87	29.12	30.31	31.22	34.98	49.31	42.49	35.46	29.35	23.14	21.95
10/17/2011	22.95	22.92	23.36	23.83	26.58	33.97	39.46	37.74	39.65	42.86	44.86	42.89
10/17/2011	42.86	40.26	37.47	34.17	34.27	36.50	48.63	41.08	33.17	28.58	24.38	22.55
10/18/2011	19.54	19.51	19.67	19.99	23.47	32.84	37.61	37.55	35.87	37.80	37.82	35.53
10/18/2011	35.74	35.72	33.48	32.66	31.86	33.68	43.72	37.78	34.36	28.90	25.43	22.97
10/19/2011	21.22	21.16	20.91	19.50	23.10	29.70	33.87	33.52	37.09	37.82	37.39	36.73
10/19/2011	36.57	35.06	32.46	31.97	32.64	33.34	47.47	38.32	32.16	28.56	25.05	24.76
10/20/2011	19.64	20.14	20.62	21.41	24.50	30.72	40.03	36.39	36.45	39.30	41.40	36.33
10/20/2011	36.13	35.83	34.33	33.64	33.64	37.19	52.59	43.08	37.27	30.30	25.02	24.91
10/21/2011	21.96	22.05	22.53	22.51	25.08	35.41	45.51	41.64	37.60	40.02	41.59	38.13
10/21/2011	35.15	33.92	32.24	31.34	30.37	32.95	39.35	34.20	31.75	29.17	23.70	22.47
10/22/2011	20.59	20.03	19.50	20.00	20.82	23.60	27.35	28.82	29.09	30.49	31.28	30.22
10/22/2011	28.89	28.04	27.57	27.83	29.62	31.56	42.98	33.28	30.08	27.09	23.88	20.97
10/23/2011	19.05	17.17	15.69	16.07	17.43	20.06	22.98	24.18	25.91	27.00	28.38	28.19
10/23/2011	27.85	27.85	28.19	27.85	28.76	32.19	44.64	36.45	31.41	26.93	22.46	20.05
10/24/2011	19.50	18.87	18.87	17.59	17.32	27.35	34.32	36.66	39.07	39.78	41.38	39.65
10/24/2011	39.22	39.60	38.02	36.68	37.29	38.23	48.48	43.05	37.25	30.20	21.54	22.57
10/25/2011	24.57	24.38	25.92	27.33	27.43	30.25	37.23	34.66	39.19	37.81	38.42	40.83
10/25/2011	44.84	40.32	37.95	37.25	33.92	38.54	49.51	39.46	31.99	26.75	21.51	18.30
10/26/2011	17.43	18.35	16.90	17.45	22.28	31.98	41.06	31.94	32.86	35.37	34.87	35.86
10/26/2011	35.76	33.99	32.19	31.96	31.46	34.54	41.85	37.38	30.23	27.43	22.48	20.59
10/27/2011	21.28	20.74	17.07	22.18	27.04	34.17	46.05	38.94	39.14	43.20	43.18	41.20
10/27/2011	41.79	38.80	38.40	37.95	38.88	42.06	55.99	42.39	39.66	34.50	26.73	25.25
10/28/2011	24.69	24.91	24.74	24.75	27.45	37.50	50.59	45.35	42.25	42.15	39.85	37.67
10/28/2011	35.59	32.44	30.73	30.77	31.30	36.54	44.52	38.40	33.88	31.10	27.55	26.07
10/29/2011	22.56	23.10	19.32	19.28	18.28	22.63	25.54	29.31	35.48	35.22	35.40	32.80
10/29/2011	29.45	28.08	27.46	27.50	27.94	32.99	40.24	35.20	31.81	27.99	24.90	20.52
10/30/2011	26.84	26.54	26.38	26.08	25.75	25.82	25.12	27.05	29.13	29.46	29.00	28.07
10/30/2011	27.84	27.28	26.71	27.18	28.07	33.49	46.95	35.90	33.75	28.45	24.23	19.22
10/31/2011	23.94	23.85	22.61	22.26	25.55	36.24	55.78	46.94	42.11	42.45	41.79	40.98
10/31/2011	37.83	36.12	34.22	32.69	32.81	38.92	53.00	47.42	39.19	32.68	29.66	25.92

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
11/1/2011	22.09	22.12	21.12	21.31	23.08	30.18	49.37	40.63	39.81	41.78	40.68	38.13
11/1/2011	38.47	36.54	33.63	32.51	31.76	36.64	46.82	39.87	35.54	30.84	26.23	25.05
11/2/2011	27.57	28.52	27.68	28.53	29.14	35.17	44.71	39.26	39.23	39.19	39.53	37.26
11/2/2011	35.72	35.10	32.80	32.48	32.32	39.07	40.20	38.72	35.47	32.21	28.62	27.26
11/3/2011	27.23	27.26	27.25	27.48	27.48	38.91	51.41	41.17	41.12	46.90	45.89	41.56
11/3/2011	40.93	40.02	35.33	34.04	35.05	45.87	50.70	42.07	38.02	32.22	29.02	25.37
11/4/2011	29.41	31.07	30.52	31.34	32.58	46.90	52.58	46.19	45.79	46.97	46.50	42.98
11/4/2011	43.01	41.82	38.17	37.29	37.25	41.39	56.93	52.09	41.77	36.56	32.97	31.86
11/5/2011	31.74	30.31	31.01	31.06	31.18	31.48	42.88	45.16	39.40	40.45	39.53	38.56
11/5/2011	35.64	31.53	30.83	31.21	32.63	37.02	39.47	32.91	34.11	34.33	32.80	32.63
11/6/2011	30.10	30.16	29.94	29.72	29.66	29.80	32.88	35.40	33.92	34.50	33.82	33.66
11/6/2011	31.60	30.74	30.33	30.46	29.82	41.21	45.48	39.49	32.88	29.83	30.82	29.57
11/7/2011	26.42	26.44	26.71	24.49	26.88	35.97	39.37	41.95	42.61	42.02	39.75	39.46
11/7/2011	36.52	36.11	33.16	31.66	33.50	43.86	43.56	38.08	35.14	30.03	24.22	22.63
11/8/2011	26.78	26.89	26.37	26.77	27.64	32.72	38.47	41.84	39.86	40.11	40.74	37.51
11/8/2011	38.87	37.52	36.34	34.38	32.85	43.09	43.32	39.86	39.72	33.72	29.42	25.79
11/9/2011	20.01	23.00	22.09	18.30	18.19	27.71	41.43	48.17	41.60	40.73	37.65	36.85
11/9/2011	37.43	36.87	35.38	33.42	32.31	36.00	42.79	40.81	39.80	33.36	28.45	24.89
11/10/2011	18.86	20.64	19.55	17.47	17.10	25.05	41.65	43.38	38.56	38.04	40.96	37.90
11/10/2011	38.04	39.01	36.42	31.48	31.66	47.97	52.47	40.63	37.15	33.37	25.35	23.44
11/11/2011	17.65	17.59	17.86	17.65	16.42	20.98	33.10	33.59	30.21	31.83	33.35	32.56
11/11/2011	32.05	31.51	29.03	26.15	24.53	42.30	44.00	35.02	33.08	30.38	24.95	23.66
11/12/2011	23.95	27.17	24.46	23.58	23.99	25.22	26.96	29.23	30.13	30.16	29.51	27.59
11/12/2011	26.74	25.89	25.61	25.47	26.22	38.18	35.95	31.39	28.23	26.04	23.33	21.95
11/13/2011	26.39	26.05	22.56	23.86	21.94	22.05	22.55	23.59	27.33	27.20	26.91	25.51
11/13/2011	25.83	25.10	24.44	24.55	26.37	37.35	37.71	37.32	33.66	28.04	26.83	28.12
11/14/2011	26.44	27.25	25.92	26.16	26.98	30.65	45.75	43.32	37.64	40.12	42.39	40.19
11/14/2011	36.68	33.70	31.08	29.87	30.21	49.22	44.25	38.98	39.00	33.66	27.93	23.86
11/15/2011	22.44	21.88	22.49	22.70	23.46	25.24	39.42	40.38	38.32	37.69	38.50	37.17
11/15/2011	34.33	33.32	31.56	30.47	32.32	47.83	41.38	38.34	34.95	32.75	26.98	24.59
11/16/2011	22.60	22.05	22.27	22.84	23.90	26.37	32.72	38.91	19.80	18.94	18.45	19.00
11/16/2011	15.73	18.41	13.52	11.02	10.06	31.15	42.31	39.51	35.64	33.74	28.05	25.04
11/17/2011	25.84	27.19	27.38	26.23	26.69	26.83	43.42	43.12	41.13	40.94	43.12	39.52
11/17/2011	34.87	32.80	32.40	32.77	32.47	47.88	45.34	44.41	38.20	32.65	25.10	28.57
11/18/2011	26.55	28.31	28.13	28.17	28.50	27.55	47.43	46.48	38.82	37.11	35.98	35.22
11/18/2011	33.81	29.84	28.58	28.17	27.99	47.85	47.38	38.61	31.67	28.70	22.87	22.34
11/19/2011	20.80	21.26	21.77	21.08	20.71	20.78	24.05	25.16	27.98	30.94	30.29	29.21
11/19/2011	24.90	24.41	22.93	22.34	23.25	39.87	36.98	32.25	26.43	23.31	21.87	17.82
11/20/2011	16.56	16.34	17.55	18.09	18.17	18.45	20.54	21.73	23.26	23.99	23.86	23.72
11/20/2011	23.82	23.28	22.34	22.35	23.94	43.56	40.53	37.93	33.14	25.26	21.78	20.07
11/21/2011	17.79	17.77	17.58	17.53	17.97	20.57	35.45	40.25	34.91	37.03	40.32	41.28
11/21/2011	39.16	36.05	34.69	29.98	31.69	60.58	60.82	50.78	43.90	34.20	26.17	22.15
11/22/2011	19.15	19.30	19.14	19.08	19.12	20.42	33.26	39.64	37.33	40.36	40.99	41.19
11/22/2011	36.64	34.48	32.12	29.73	30.17	55.21	47.30	46.10	41.83	32.37	26.07	23.01
11/23/2011	23.95	23.95	24.32	24.20	25.02	30.89	51.54	48.30	45.89	42.52	43.13	42.11
11/23/2011	41.09	35.48	31.70	30.62	30.68	51.93	43.27	41.70	36.81	33.90	27.66	24.48
11/24/2011	25.41	24.21	24.46	25.47	26.40	25.25	24.81	26.74	28.04	30.64	32.05	32.72
11/24/2011	28.23	26.92	26.42	25.51	25.89	29.04	27.54	28.34	28.25	28.34	25.42	23.66
11/25/2011	21.63	21.28	21.58	21.92	23.17	22.69	28.41	33.61	34.21	34.54	34.68	34.31
11/25/2011	33.96	33.53	32.05	32.41	33.46	54.02	52.02	45.69	43.42	37.12	30.51	28.32
11/26/2011	24.07	23.62	22.96	22.98	23.05	23.82	27.75	27.46	29.40	31.28	31.22	30.02
11/26/2011	27.50	25.66	24.69	24.59	25.36	45.09	35.14	35.94	32.99	28.68	27.71	24.37
11/27/2011	25.27	25.13	26.15	25.24	24.49	23.79	25.33	27.20	26.05	26.14	25.84	25.62
11/27/2011	25.04	25.13	24.21	24.41	26.61	41.95	35.27	35.57	34.44	30.59	26.30	26.13
11/28/2011	26.56	27.44	26.75	26.42	26.56	26.28	36.91	47.03	41.57	47.73	50.32	47.43
11/28/2011	43.59	38.56	36.95	36.62	38.30	54.94	46.74	43.25	46.45	40.37	33.73	22.06
11/29/2011	23.30	25.39	23.50	24.09	24.41	30.73	37.12	48.79	37.81	43.28	43.39	43.47
11/29/2011	43.34	43.05	39.85	39.89	39.81	48.44	47.43	44.85	39.09	36.23	32.63	30.34
11/30/2011	22.44	23.00	23.32	23.82	24.51	28.46	37.73	46.27	40.95	40.99	42.40	40.16
11/30/2011	35.57	34.75	32.98	32.32	36.25	57.80	51.60	46.57	44.85	39.17	30.56	24.60

Date	HOUR ENDING											
	1	2	3	4	5	6	7	8	9	10	11	12
	13	14	15	16	17	18	19	20	21	22	23	24
12/1/2011	23.79	22.87	22.81	24.02	24.25	25.97	37.00	46.92	44.07	40.09	40.01	38.84
12/1/2011	32.89	30.21	26.91	25.83	29.91	54.45	47.22	41.45	39.69	39.49	27.42	22.35
12/2/2011	24.28	24.64	25.04	25.20	25.64	27.34	39.25	46.81	43.17	40.36	41.62	37.88
12/2/2011	31.20	30.82	26.73	27.47	28.45	49.08	45.53	41.19	39.31	35.22	27.44	24.34
12/3/2011	26.79	25.19	24.85	25.18	24.71	25.36	23.82	24.07	26.22	31.18	33.70	31.65
12/3/2011	26.07	25.35	24.57	24.67	23.56	45.17	41.69	38.06	37.25	31.67	27.44	24.69
12/4/2011	26.64	25.84	25.59	25.04	24.00	23.95	22.87	23.87	25.45	26.61	24.45	24.42
12/4/2011	25.08	24.85	24.68	24.57	27.64	44.11	42.95	41.30	36.96	33.84	25.65	25.79
12/5/2011	27.52	27.41	27.22	26.84	26.99	28.91	39.32	46.51	44.88	41.38	42.97	40.94
12/5/2011	38.65	36.96	31.17	28.30	32.97	61.05	52.33	51.79	49.76	43.78	31.23	29.18
12/6/2011	27.47	26.94	26.61	26.91	26.78	29.75	45.55	46.80	44.10	44.44	44.17	40.21
12/6/2011	38.48	36.97	32.98	29.95	33.95	56.39	50.19	45.62	44.14	43.96	33.40	38.51
12/7/2011	24.89	27.35	26.42	26.19	26.34	27.93	41.27	52.55	43.56	45.44	50.40	44.26
12/7/2011	39.67	39.39	34.13	33.74	37.51	62.26	58.36	56.68	47.66	45.79	31.73	25.07
12/8/2011	38.98	39.64	39.20	38.39	38.38	41.47	50.96	55.61	42.29	40.46	40.05	36.90
12/8/2011	30.97	30.64	25.86	24.01	31.45	56.32	49.92	43.13	42.89	38.37	42.30	37.96
12/9/2011	29.31	29.16	28.15	27.67	28.69	31.52	44.89	45.54	42.17	42.37	45.51	40.11
12/9/2011	35.64	32.75	30.24	27.84	28.40	46.67	43.03	43.42	40.33	33.55	24.29	22.39
12/10/2011	31.36	31.68	31.02	29.82	28.74	32.79	31.68	34.44	21.65	23.28	24.32	22.06
12/10/2011	21.35	20.12	19.91	20.07	21.58	40.15	34.77	31.30	29.68	26.65	33.40	29.41
12/11/2011	22.86	21.18	19.73	18.33	17.89	20.22	22.01	30.81	21.90	24.23	24.36	25.15
12/11/2011	24.56	24.89	24.15	24.61	26.01	48.89	49.92	44.84	41.62	40.38	33.64	28.83
12/12/2011	25.73	25.46	25.01	26.30	25.07	27.63	41.30	55.60	52.17	47.39	47.88	48.28
12/12/2011	45.51	46.06	41.34	42.30	46.92	60.46	65.82	58.73	55.43	50.30	46.76	41.99
12/13/2011	43.97	42.28	41.57	41.10	41.63	47.84	55.94	66.62	63.58	59.42	56.16	54.07
12/13/2011	47.31	43.25	40.61	38.93	43.06	70.45	73.17	60.34	58.68	56.37	51.34	42.10
12/14/2011	33.20	29.18	28.52	27.82	28.75	33.55	51.94	66.90	62.73	60.88	57.52	53.61
12/14/2011	45.81	43.22	40.08	37.69	42.79	64.33	65.63	62.60	58.21	54.10	38.34	29.05
12/15/2011	24.91	23.15	23.19	22.34	22.85	24.12	43.03	63.25	51.35	56.27	54.66	52.90
12/15/2011	43.66	38.86	34.32	32.31	36.69	61.45	64.03	53.13	53.62	48.00	32.99	27.47
12/16/2011	24.87	23.94	22.67	22.45	23.35	28.98	49.99	41.83	40.78	39.52	39.31	38.19
12/16/2011	33.88	31.70	29.02	27.38	30.16	47.22	51.32	44.75	43.73	37.67	30.22	30.65
12/17/2011	23.83	22.73	21.66	19.86	19.84	19.36	20.51	23.70	30.05	33.78	35.55	29.75
12/17/2011	27.21	24.81	23.39	23.70	24.37	42.10	48.04	41.38	36.15	34.10	27.65	24.35
12/18/2011	28.05	18.74	17.65	17.35	16.88	16.98	17.42	19.24	21.58	22.11	24.69	23.19
12/18/2011	22.45	21.30	19.48	19.70	20.47	39.27	51.70	44.34	39.01	35.66	29.05	24.29
12/19/2011	19.63	18.21	18.03	16.86	17.66	19.85	37.21	43.12	44.65	44.01	40.24	36.05
12/19/2011	32.31	30.01	27.99	27.48	28.47	49.90	51.63	45.00	39.29	34.37	27.44	20.90
12/20/2011	23.44	23.20	22.76	22.35	22.81	22.93	30.03	41.54	41.03	40.82	40.20	38.21
12/20/2011	36.98	34.19	30.13	29.73	30.64	52.14	51.25	42.64	39.77	38.25	30.24	25.39
12/21/2011	29.71	30.02	30.13	30.03	30.82	30.50	40.84	42.98	39.42	40.11	40.10	41.31
12/21/2011	36.62	35.55	33.71	30.61	32.23	51.51	50.35	44.47	38.98	37.47	31.11	28.10
12/22/2011	31.68	31.20	31.06	30.71	31.05	32.15	36.96	42.09	39.46	41.54	41.92	40.18
12/22/2011	36.04	34.47	32.35	30.59	32.35	43.64	45.29	40.24	37.02	34.91	28.72	27.16
12/23/2011	25.63	25.15	24.86	23.18	23.53	24.13	26.94	29.29	29.35	28.81	29.31	28.53
12/23/2011	24.79	24.58	24.46	24.76	23.92	31.42	28.56	29.11	29.53	28.23	25.98	23.88
12/24/2011	20.62	21.64	19.66	19.65	19.45	19.04	18.29	20.14	20.68	22.78	21.51	21.62
12/24/2011	21.01	20.49	20.06	20.15	20.39	28.00	24.19	24.43	25.66	25.81	25.36	22.40
12/25/2011	23.79	22.34	20.55	19.83	19.08	18.88	19.17	23.29	25.14	26.49	26.72	27.05
12/25/2011	26.97	26.71	27.41	27.38	28.06	42.17	47.85	42.90	38.59	36.38	30.91	29.54
12/26/2011	27.92	28.11	27.78	27.61	27.19	28.92	31.70	39.73	39.59	39.43	39.44	40.20
12/26/2011	35.82	33.13	31.25	28.37	30.58	44.49	54.11	44.27	40.67	40.03	28.32	27.38
12/27/2011	28.29	27.42	27.08	25.95	26.95	29.38	28.81	37.37	40.12	42.82	43.76	43.61
12/27/2011	41.76	37.68	31.84	30.14	30.33	43.83	53.58	42.65	36.45	42.43	29.70	23.57
12/28/2011	34.47	36.46	34.96	32.02	31.23	35.44	36.29	49.49	42.52	42.59	40.93	44.66
12/28/2011	41.86	35.11	29.91	29.86	30.69	47.30	45.41	45.53	43.67	43.46	32.89	29.40
12/29/2011	27.25	27.55	27.34	26.98	26.55	28.87	32.82	35.12	26.16	30.03	28.80	29.48
12/29/2011	27.53	25.69	23.42	24.64	26.16	38.81	37.86	30.13	28.43	32.12	27.18	25.77
12/30/2011	18.75	18.88	16.26	15.03	16.02	16.20	20.40	23.23	22.49	23.98	24.23	24.97
12/30/2011	24.66	23.45	22.00	21.18	22.07	30.43	32.52	23.95	22.42	22.54	20.69	19.09
12/31/2011	24.95	25.06	24.37	22.87	22.43	22.67	23.70	26.50	28.89	36.48	47.42	45.88
12/31/2011	37.72	33.44	28.21	27.22	29.31	53.96	69.10	55.08	51.71	43.88	43.07	40.25

Seasonal Load Shapes (2010 Typical Week)																	
Hr	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Emerg Min**	**Econ Min**	**Econ Max -400 MW**	**Econ Max**	**NDC Emerg Max**
1	1764	1826	1827	1570	1653	1757	1826	1833	1693	1720	1738	1759	1355	1625	2782	3182	3422
2	1735	1728	1829	1565	1599	1686	1785	1777	1664	1684	1718	1729	1355	1625	2782	3182	3422
3	1712	1653	1842	1635	1517	1664	1736	1755	1643	1676	1701	1686	1355	1625	2782	3182	3422
4	1728	1744	1835	1659	1567	1655	1714	1762	1698	1696	1686	1705	1355	1625	2782	3182	3422
5	1769	1860	1878	1782	1573	1706	1811	1812	1765	1733	1705	1746	1355	1625	2782	3182	3422
6	1816	1927	2017	1901	1662	1726	1835	1902	1871	1808	1787	1775	1355	1625	2782	3182	3422
7	1883	2035	2168	1933	1730	1840	1955	1965	2033	2007	1933	1934	1355	1625	2782	3182	3422
8	1919	2111	2323	1916	1845	1921	2031	2017	2066	2013	1960	2052	1355	1625	2782	3182	3422
9	1944	2133	2209	2034	1949	2026	2162	2148	2137	2077	1974	2058	1355	1625	2782	3182	3422
10	1969	2138	2297	2074	2058	2089	2284	2243	2172	2213	1975	2131	1355	1625	2782	3182	3422
11	2018	2167	2214	2125	2090	2186	2358	2363	2203	2307	2075	2137	1355	1625	2782	3182	3422
12	1998	2184	2147	2158	2161	2271	2492	2450	2255	2331	2238	2191	1355	1625	2782	3182	3422
13	1946	2116	2142	2134	2180	2374	2517	2565	2349	2401	2038	2094	1355	1625	2782	3182	3422
14	1931	2061	2115	2139	2285	2364	2407	2652	2386	2270	2046	2090	1355	1625	2782	3182	3422
15	1950	2021	2042	2110	2240	2277	2495	2624	2366	2277	2031	2001	1355	1625	2782	3182	3422
16	1967	2005	1982	2014	2293	2282	2427	2585	2399	2172	1989	1936	1355	1625	2782	3182	3422
17	1964	2037	1959	1904	2337	2289	2378	2534	2351	2108	1994	1926	1355	1625	2782	3182	3422
18	2058	2064	1964	1960	2318	2256	2361	2432	2321	2057	2185	2161	1355	1625	2782	3182	3422
19	2073	2097	2010	1897	2173	2324	2289	2390	2282	2168	2168	2308	1355	1625	2782	3182	3422
20	2045	2104	2019	1854	2144	2237	2246	2317	2234	2051	2074	2167	1355	1625	2782	3182	3422
21	2006	2100	2093	1958	2131	2207	2219	2283	2187	2037	2183	2128	1355	1625	2782	3182	3422
22	1936	2054	1971	1918	2079	2120	2118	2218	2094	1936	2058	2101	1355	1625	2782	3182	3422
23	1890	1993	1904	1838	2021	1995	2027	2139	2051	1865	1939	1956	1355	1625	2782	3182	3422
24	1863	1973	1909	1856	1911	1938	1964	2055	2061	1798	1925	1910	1355	1625	2782	3182	3422
25	1837	1899	1905	1771	1856	1821	1864	1961	1941	1779	1844	1786	1355	1625	2782	3182	3422
26	1827	1884	1874	1803	1763	1774	1789	1926	1861	1797	1818	1714	1355	1625	2782	3182	3422
27	1781	1824	1864	1726	1710	1789	1743	1826	1875	1776	1761	1673	1355	1625	2782	3182	3422
28	1739	1879	1869	1665	1691	1775	1757	1806	1880	1746	1755	1666	1355	1625	2782	3182	3422
29	1754	1839	1937	1799	1770	1767	1843	1868	1988	1800	1797	1727	1355	1625	2782	3182	3422
30	1825	1931	2046	1888	1755	1845	1924	1996	2099	1891	1903	1782	1355	1625	2782	3182	3422
31	1909	2058	2257	1970	1876	1926	1971	2058	2166	2066	2081	1844	1355	1625	2782	3182	3422
32	1978	2124	2163	2065	1942	1950	2023	2067	2199	2247	2064	1978	1355	1625	2782	3182	3422
33	2017	2141	2348	2072	2035	2047	2090	2142	2263	2159	2049	2033	1355	1625	2782	3182	3422
34	2053	2171	2306	2023	2105	2139	2181	2232	2382	2193	2108	2125	1355	1625	2782	3182	3422
35	2084	2193	2237	2041	2165	2294	2502	2350	2413	2150	2194	2122	1355	1625	2782	3182	3422
36	2130	2229	2127	2078	2218	2438	2648	2417	2450	2146	2176	2103	1355	1625	2782	3182	3422
37	2126	2206	2136	2054	2298	2477	2771	2504	2473	2241	2159	2116	1355	1625	2782	3182	3422
38	2121	2162	2122	2031	2415	2583	2683	2741	2644	2262	2137	2109	1355	1625	2782	3182	3422
39	2078	2107	2065	1938	2465	2642	2711	2970	2750	2074	2097	2054	1355	1625	2782	3182	3422
40	2040	2082	2060	1944	2545	2563	2747	2998	2591	2139	2069	1987	1355	1625	2782	3182	3422
41	2015	2059	2101	1923	2517	2552	2712	3156	2517	2134	2147	1959	1355	1625	2782	3182	3422
42	2081	2049	2022	2011	2442	2465	2671	2941	2481	2155	2269	2176	1355	1625	2782	3182	3422

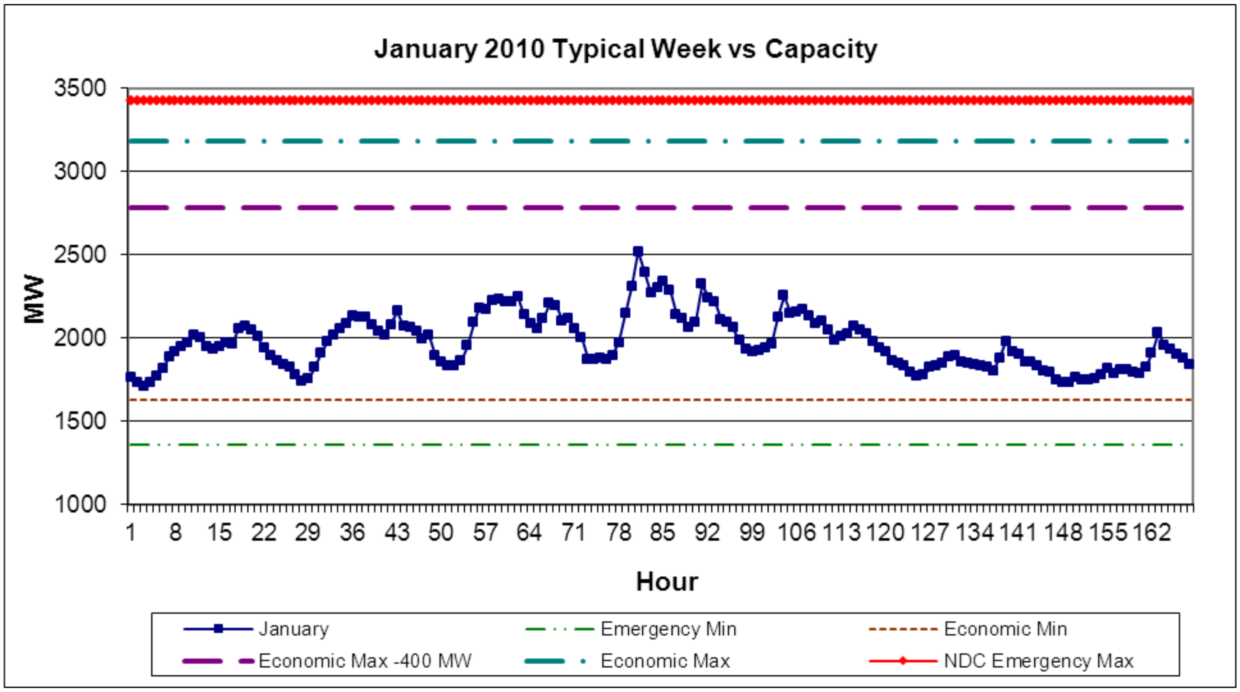
Seasonal Load Shapes (2010 Typical Week)																	
Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Emerg Min	Econ Min	Econ Max -400 MW	Econ Max	NDC Emerg Max
43	2159	2130	2050	1909	2196	2429	2601	2770	2456	2338	2353	2234	1355	1625	2782	3182	3422
44	2067	2171	2158	1903	2152	2285	2512	2460	2443	2200	2247	2353	1355	1625	2782	3182	3422
45	2060	2145	2164	2008	2125	2180	2465	2443	2410	2178	2201	2312	1355	1625	2782	3182	3422
46	2037	2095	2083	2003	2074	2114	2375	2337	2303	1943	2188	2212	1355	1625	2782	3182	3422
47	1995	2085	2046	1884	1896	2032	2258	2227	2145	1834	2079	2119	1355	1625	2782	3182	3422
48	2013	2046	1992	1875	1870	1968	2112	2175	2082	1831	1982	1997	1355	1625	2782	3182	3422
49	1893	1983	1872	1804	1786	1916	2037	2073	2087	1784	1948	1885	1355	1625	2782	3182	3422
50	1852	1909	1850	1788	1723	1864	1997	2034	2043	1735	1949	1860	1355	1625	2782	3182	3422
51	1828	1890	1839	1697	1646	1832	1989	1992	1948	1769	1871	1910	1355	1625	2782	3182	3422
52	1829	1975	1846	1679	1607	1879	1995	1933	1878	1772	1858	1838	1355	1625	2782	3182	3422
53	1861	1989	1886	1814	1629	1877	2048	1954	1883	1815	1929	1895	1355	1625	2782	3182	3422
54	1953	2055	1995	1907	1705	1898	2050	2009	2067	1909	1986	1965	1355	1625	2782	3182	3422
55	2093	2180	2111	1992	1853	1953	2069	2077	2149	2075	2103	2076	1355	1625	2782	3182	3422
56	2179	2219	2129	2017	1899	2057	2171	2152	2194	1970	2128	2259	1355	1625	2782	3182	3422
57	2169	2242	2183	2075	1978	2094	2318	2238	2209	1980	2218	2330	1355	1625	2782	3182	3422
58	2224	2305	2218	2058	2138	2084	2396	2313	2257	1994	2151	2476	1355	1625	2782	3182	3422
59	2228	2214	2290	2107	2186	2108	2561	2401	2296	2028	2145	2275	1355	1625	2782	3182	3422
60	2214	2252	2387	2115	2269	2135	2755	2497	2279	2053	2152	2321	1355	1625	2782	3182	3422
61	2215	2267	2243	2082	2380	2147	2924	2708	2286	2120	2230	2173	1355	1625	2782	3182	3422
62	2249	2233	2265	2084	2551	2246	2929	3086	2301	2096	2116	2099	1355	1625	2782	3182	3422
63	2138	2199	2200	2098	2596	2314	2962	3067	2265	1947	2089	2197	1355	1625	2782	3182	3422
64	2088	2160	2145	2037	2632	2492	2883	2865	2249	1897	2003	2037	1355	1625	2782	3182	3422
65	2058	2142	2030	1999	2571	2681	2829	3026	2236	1903	1998	2028	1355	1625	2782	3182	3422
66	2113	2153	2081	1985	2399	2703	2742	2901	2268	1911	2233	2237	1355	1625	2782	3182	3422
67	2207	2216	2172	1996	2235	2420	2704	2686	2221	2086	2296	2378	1355	1625	2782	3182	3422
68	2195	2239	2338	1987	2117	2241	2528	2415	2289	2000	2105	2252	1355	1625	2782	3182	3422
69	2102	2211	2286	2061	2101	2020	2476	2383	2274	1931	2111	2268	1355	1625	2782	3182	3422
70	2120	2149	2179	1947	2013	1992	2445	2320	2121	1900	2236	2200	1355	1625	2782	3182	3422
71	2053	2129	2107	1863	1927	1935	2309	2167	2074	1759	2072	2278	1355	1625	2782	3182	3422
72	2003	2090	2086	1871	1840	1870	2184	2062	2020	1722	1991	2139	1355	1625	2782	3182	3422
73	1872	2001	2005	1839	1794	1751	2054	1999	2039	1739	1779	1932	1355	1625	2782	3182	3422
74	1870	1963	1986	1734	1722	1701	2001	1912	1991	1749	1713	1881	1355	1625	2782	3182	3422
75	1877	1957	1893	1755	1679	1704	1874	1865	1954	1730	1730	1828	1355	1625	2782	3182	3422
76	1867	1967	1924	1794	1698	1691	1872	1860	1970	1760	1673	1818	1355	1625	2782	3182	3422
77	1894	2001	1956	1886	1757	1733	1928	1910	2017	1787	1811	1834	1355	1625	2782	3182	3422
78	1972	2068	2034	2021	1792	1784	1934	1944	2119	1861	1954	1891	1355	1625	2782	3182	3422
79	2146	2164	2234	2080	1890	1905	2004	1989	2251	2028	2006	1995	1355	1625	2782	3182	3422
80	2307	2220	2274	2155	1959	1957	2079	2081	2245	1989	2010	2002	1355	1625	2782	3182	3422
81	2517	2256	2413	2182	2025	2015	2235	2187	2340	2083	2161	2041	1355	1625	2782	3182	3422
82	2396	2279	2442	2211	2062	2097	2334	2298	2392	2113	2130	2112	1355	1625	2782	3182	3422
83	2267	2301	2511	2196	2081	2142	2391	2397	2418	2204	2157	2140	1355	1625	2782	3182	3422
84	2300	2324	2430	2200	2087	2266	2610	2554	2423	2235	2132	2143	1355	1625	2782	3182	3422

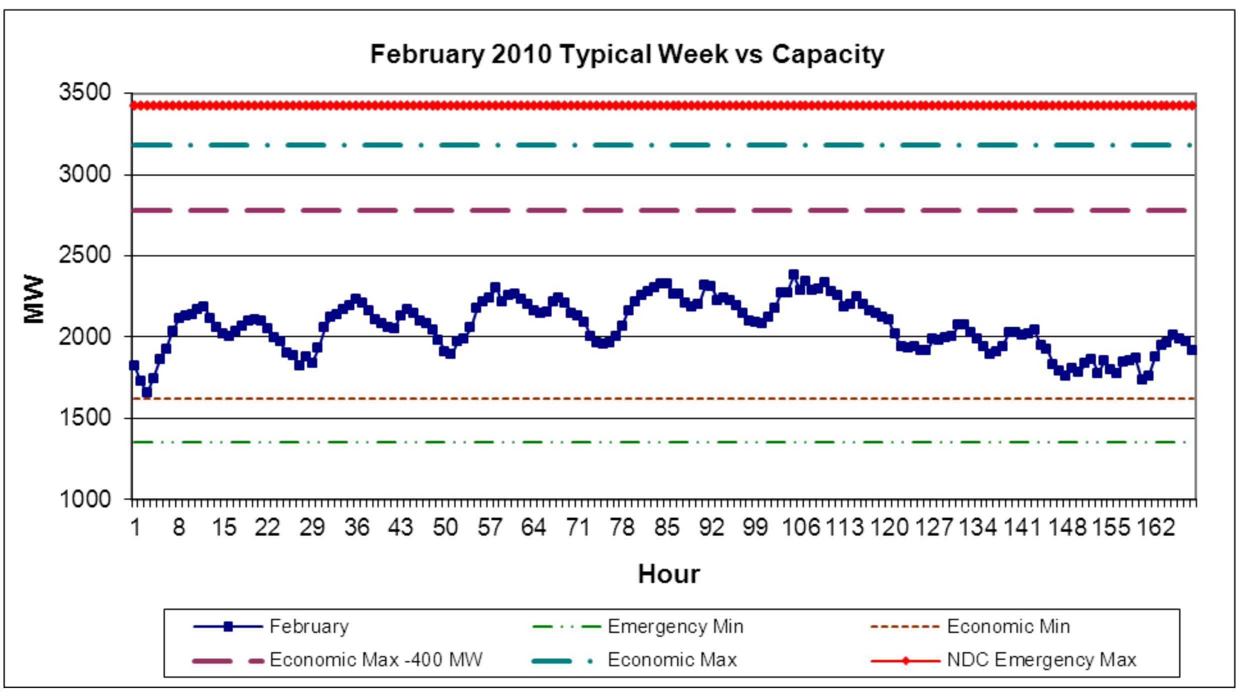
Seasonal Load Shapes (2010 Typical Week)																	
Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Emerg Min	Econ Min	Econ Max -400 MW	Econ Max	NDC Emerg Max
85	2341	2328	2366	2246	2111	2331	2730	2724	2470	2226	2260	2063	1355	1625	2782	3182	3422
86	2287	2261	2400	2269	2112	2534	2869	2789	2844	2103	2256	2011	1355	1625	2782	3182	3422
87	2141	2263	2379	2177	2083	2497	2903	2833	2776	2046	2140	2031	1355	1625	2782	3182	3422
88	2116	2208	2188	2111	2067	2457	2790	2746	2710	2100	2035	2018	1355	1625	2782	3182	3422
89	2064	2186	2070	2148	2039	2470	2822	2842	2524	2041	1993	2014	1355	1625	2782	3182	3422
90	2097	2197	2095	2105	2044	2392	2693	2761	2496	1975	2158	2147	1355	1625	2782	3182	3422
91	2324	2316	2153	2046	1972	2381	2572	2516	2557	2223	2223	2339	1355	1625	2782	3182	3422
92	2242	2310	2316	1974	1904	2251	2458	2382	2613	2189	2210	2297	1355	1625	2782	3182	3422
93	2219	2225	2358	2051	1874	2166	2548	2367	2467	2118	2214	2302	1355	1625	2782	3182	3422
94	2108	2243	2223	1965	1834	2160	2416	2331	2437	1962	2241	2360	1355	1625	2782	3182	3422
95	2091	2223	2116	1893	1726	2043	2346	2198	2404	1857	2114	2108	1355	1625	2782	3182	3422
96	2060	2191	2078	1867	1696	1973	2270	2111	2309	1836	2013	2081	1355	1625	2782	3182	3422
97	1984	2144	1948	1834	1642	1912	2207	2014	2155	1839	1906	1928	1355	1625	2782	3182	3422
98	1933	2099	1979	1797	1582	1813	2146	1894	2090	1859	1846	1903	1355	1625	2782	3182	3422
99	1915	2092	1926	1760	1541	1809	2086	1890	2078	1870	1825	1756	1355	1625	2782	3182	3422
100	1922	2086	1885	1766	1553	1748	2103	1857	2115	1895	1864	1770	1355	1625	2782	3182	3422
101	1939	2120	1987	1849	1638	1803	2131	1880	2109	1889	1908	1788	1355	1625	2782	3182	3422
102	1960	2176	2054	1929	1741	1819	2140	1972	2230	1944	2015	1875	1355	1625	2782	3182	3422
103	2123	2270	2252	1977	1798	1867	2194	2025	2372	2123	2161	2045	1355	1625	2782	3182	3422
104	2252	2272	2193	2027	1806	1901	2344	2086	2358	2023	2001	2243	1355	1625	2782	3182	3422
105	2150	2380	2324	2068	1830	2009	2484	2181	2395	1963	2067	2163	1355	1625	2782	3182	3422
106	2154	2290	2228	2118	1894	2195	2589	2261	2355	1992	2019	2286	1355	1625	2782	3182	3422
107	2173	2346	2282	2123	1915	2298	2836	2378	2327	2070	2093	2187	1355	1625	2782	3182	3422
108	2133	2287	2174	2128	1939	2608	3000	2479	2344	2127	2191	2152	1355	1625	2782	3182	3422
109	2087	2295	2158	2144	2005	2722	3050	2608	2317	2039	2123	2027	1355	1625	2782	3182	3422
110	2100	2335	2140	2165	1986	2807	3227	2879	2334	2091	2170	2020	1355	1625	2782	3182	3422
111	2048	2283	2102	2090	2011	2841	3130	3011	2313	1968	2086	2016	1355	1625	2782	3182	3422
112	1988	2255	2058	2077	1932	3014	3037	2731	2293	1984	2040	1963	1355	1625	2782	3182	3422
113	2008	2188	2027	2002	1975	2765	2986	2643	2261	1952	2043	2005	1355	1625	2782	3182	3422
114	2021	2201	2015	1982	1918	2543	2891	2487	2176	1997	2099	2173	1355	1625	2782	3182	3422
115	2070	2248	2061	1950	1907	2516	2759	2425	2172	1969	2052	2407	1355	1625	2782	3182	3422
116	2050	2204	2048	1954	1821	2344	2618	2340	2131	2019	2055	2334	1355	1625	2782	3182	3422
117	2025	2159	2098	1990	1811	2201	2534	2357	2161	1941	2059	2230	1355	1625	2782	3182	3422
118	1975	2143	2099	1882	1780	2172	2412	2271	2092	1883	1964	2219	1355	1625	2782	3182	3422
119	1941	2122	2038	1818	1682	2062	2242	2162	2071	1806	1895	2225	1355	1625	2782	3182	3422
120	1920	2102	2027	1776	1667	1942	2096	2082	2016	1791	1928	2170	1355	1625	2782	3182	3422
121	1864	2016	1967	1704	1589	1884	2009	1980	1830	1744	1878	2066	1355	1625	2782	3182	3422
122	1847	1937	1922	1627	1470	1854	1914	1921	1844	1725	1821	1889	1355	1625	2782	3182	3422
123	1830	1934	1866	1602	1460	1780	1897	1886	1793	1708	1782	1863	1355	1625	2782	3182	3422
124	1792	1941	1865	1556	1526	1712	1895	1788	1771	1706	1718	1840	1355	1625	2782	3182	3422
125	1771	1918	1857	1619	1560	1741	1818	1783	1743	1697	1740	1821	1355	1625	2782	3182	3422
126	1777	1913	1914	1694	1622	1720	1853	1816	1776	1711	1829	1809	1355	1625	2782	3182	3422

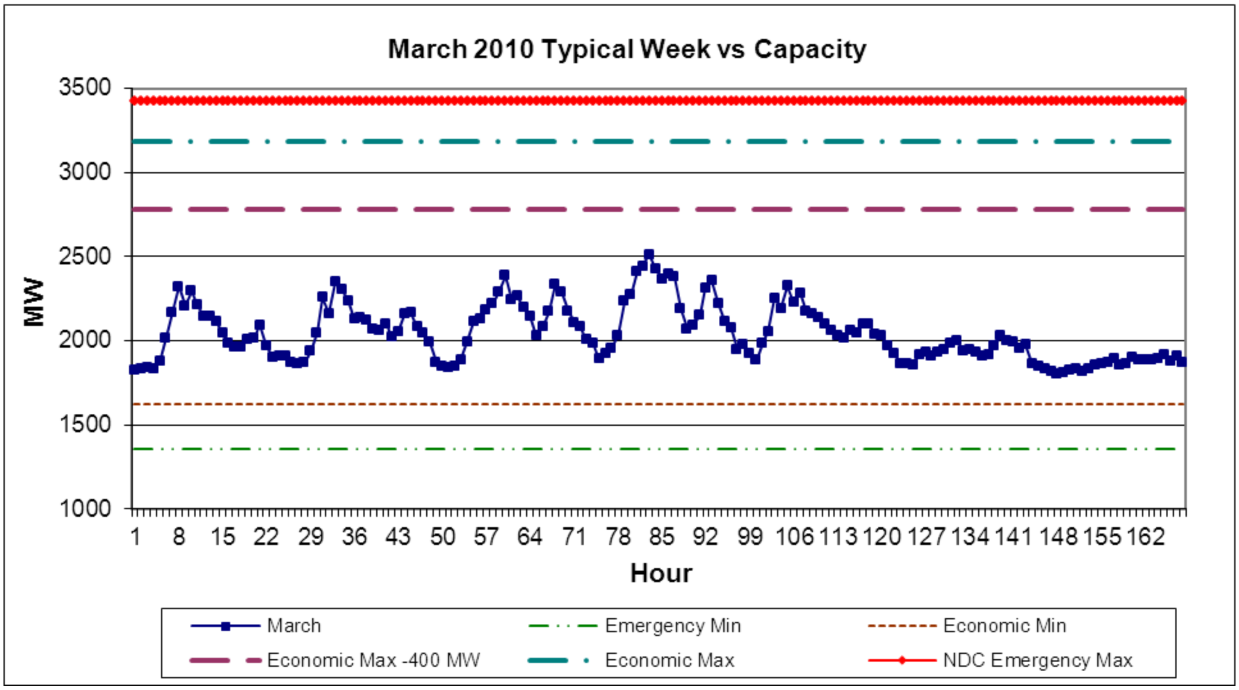
Seasonal Load Shapes (2010 Typical Week)																	
Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Emerg Min	Econ Min	Econ Max -400 MW	Econ Max	NDC Emerg Max
127	1823	1987	1933	1710	1592	1771	1858	1840	1839	1752	1850	1919	1355	1625	2782	3182	3422
128	1833	1980	1911	1701	1626	1860	1943	1820	1868	1756	1813	1947	1355	1625	2782	3182	3422
129	1849	1998	1935	1845	1669	1932	2042	1905	1886	1789	1880	1968	1355	1625	2782	3182	3422
130	1885	2007	1950	1889	1751	1943	2198	1938	1934	1822	1890	2077	1355	1625	2782	3182	3422
131	1897	2077	1987	1915	1858	2052	2299	2041	1975	1855	1885	2091	1355	1625	2782	3182	3422
132	1854	2073	1999	1876	1881	2102	2369	2121	2009	1923	1874	2036	1355	1625	2782	3182	3422
133	1850	2025	1938	1820	1925	2264	2543	2171	1979	1950	1919	1898	1355	1625	2782	3182	3422
134	1839	1985	1943	1823	1963	2386	2608	2159	1919	1928	1853	1906	1355	1625	2782	3182	3422
135	1833	1939	1928	1790	1998	2409	2675	2182	1889	1963	1816	1847	1355	1625	2782	3182	3422
136	1822	1896	1906	1744	2031	2399	2662	2209	1897	2020	1804	1871	1355	1625	2782	3182	3422
137	1804	1907	1917	1809	1954	2309	2594	2249	1902	2059	1856	1812	1355	1625	2782	3182	3422
138	1875	1943	1968	1741	1970	2403	2632	2252	1957	2035	1912	1941	1355	1625	2782	3182	3422
139	1979	2027	2031	1831	1957	2353	2514	2189	1997	2047	1956	2206	1355	1625	2782	3182	3422
140	1914	2031	2002	1852	1878	2117	2349	2089	2023	1956	1909	2073	1355	1625	2782	3182	3422
141	1900	2014	1989	1801	1864	2068	2330	2105	2006	1917	1899	1981	1355	1625	2782	3182	3422
142	1852	2023	1953	1750	1803	2035	2264	2046	1906	1814	1834	1946	1355	1625	2782	3182	3422
143	1858	2040	1976	1688	1702	1979	2144	1958	1811	1819	1838	1952	1355	1625	2782	3182	3422
144	1835	1949	1864	1588	1613	1816	1979	1795	1730	1714	1823	1867	1355	1625	2782	3182	3422
145	1798	1922	1844	1536	1475	1710	1882	1768	1718	1682	1744	1816	1355	1625	2782	3182	3422
146	1790	1832	1830	1507	1449	1674	1770	1751	1613	1652	1687	1734	1355	1625	2782	3182	3422
147	1750	1793	1817	1468	1403	1608	1678	1748	1587	1660	1642	1694	1355	1625	2782	3182	3422
148	1729	1761	1801	1415	1346	1624	1583	1731	1543	1655	1611	1699	1355	1625	2782	3182	3422
149	1732	1809	1813	1480	1422	1559	1622	1677	1516	1600	1633	1659	1355	1625	2782	3182	3422
150	1760	1786	1825	1527	1379	1523	1490	1722	1629	1664	1654	1646	1355	1625	2782	3182	3422
151	1746	1834	1831	1531	1391	1498	1637	1707	1459	1670	1669	1656	1355	1625	2782	3182	3422
152	1744	1864	1820	1540	1441	1640	1668	1742	1480	1630	1684	1754	1355	1625	2782	3182	3422
153	1756	1777	1833	1581	1491	1892	1799	1775	1673	1690	1694	1791	1355	1625	2782	3182	3422
154	1778	1857	1854	1598	1675	1990	1983	1918	1723	1694	1771	1795	1355	1625	2782	3182	3422
155	1814	1799	1860	1612	1716	2000	2061	2053	1706	1704	1768	1851	1355	1625	2782	3182	3422
156	1785	1771	1873	1610	1796	1984	2123	2117	1756	1727	1790	1819	1355	1625	2782	3182	3422
157	1805	1844	1893	1646	1866	2023	2176	2195	1802	1823	1785	1723	1355	1625	2782	3182	3422
158	1808	1852	1852	1673	1936	2078	2211	2236	1818	1848	1776	1719	1355	1625	2782	3182	3422
159	1797	1867	1862	1722	2010	2127	2254	2273	1852	1925	1735	1741	1355	1625	2782	3182	3422
160	1789	1733	1898	1682	2051	2226	2223	2294	1913	1920	1698	1652	1355	1625	2782	3182	3422
161	1821	1759	1888	1691	2053	2184	2267	2422	1923	1915	1680	1681	1355	1625	2782	3182	3422
162	1905	1874	1882	1808	2017	2217	2313	2412	1942	1846	1868	1877	1355	1625	2782	3182	3422
163	2028	1952	1889	1829	1992	2153	2274	2325	1965	1873	1969	2049	1355	1625	2782	3182	3422
164	1958	1964	1894	1861	1889	2073	2229	2254	2002	1852	1942	1986	1355	1625	2782	3182	3422
165	1928	2011	1920	1880	1900	2039	2150	2224	1924	1826	1936	2007	1355	1625	2782	3182	3422
166	1903	1990	1881	1843	1885	2006	2076	2126	1848	1767	1887	1969	1355	1625	2782	3182	3422
167	1881	1971	1912	1784	1837	1963	2014	2029	1824	1794	1862	1943	1355	1625	2782	3182	3422
168	1841	1915	1867	1642	1745	1888	1904	1923	1758	1786	1800	1855	1355	1625	2782	3182	3422

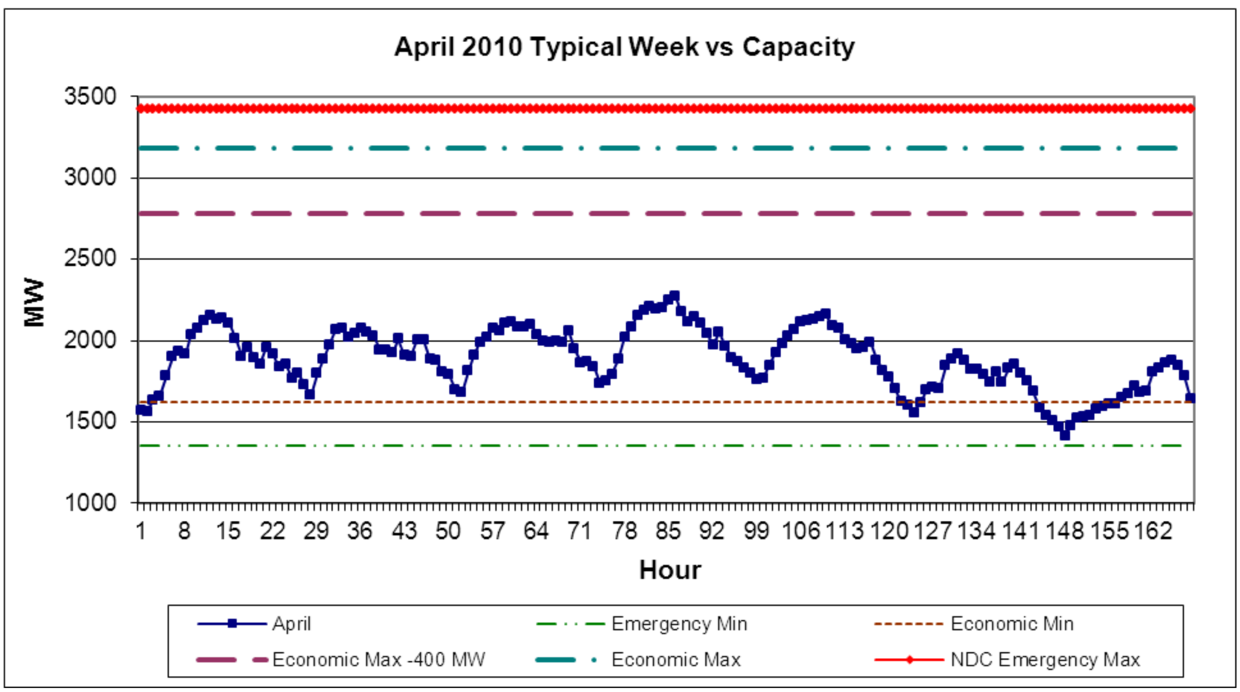
	Level Number				
	Fourth	Third	Second	First	NDC
Unit	Emergency Min	Economic Min		Economic Max	Emergency Max
7	110	120		150	160
8	240	250		310	320
12	290	300		450	469
14	280	300		410	431
15	180	250		450	472
17	125	200		355	361
18	125	200		355	361
Sugar Creek	0	0		480	535
16A	0	0		78	78
16B	0	0		77	77
10	0	0		31	31
9	0	0		17	17
Norway	2	2		2	4
Oakdale	3	3		3	6
Buffalo Ridge	0	0		11	50
Barton	0	0		3	50
TOTAL	**1,355**	**1,625**	**2,782**	**3,182**	**3,422**

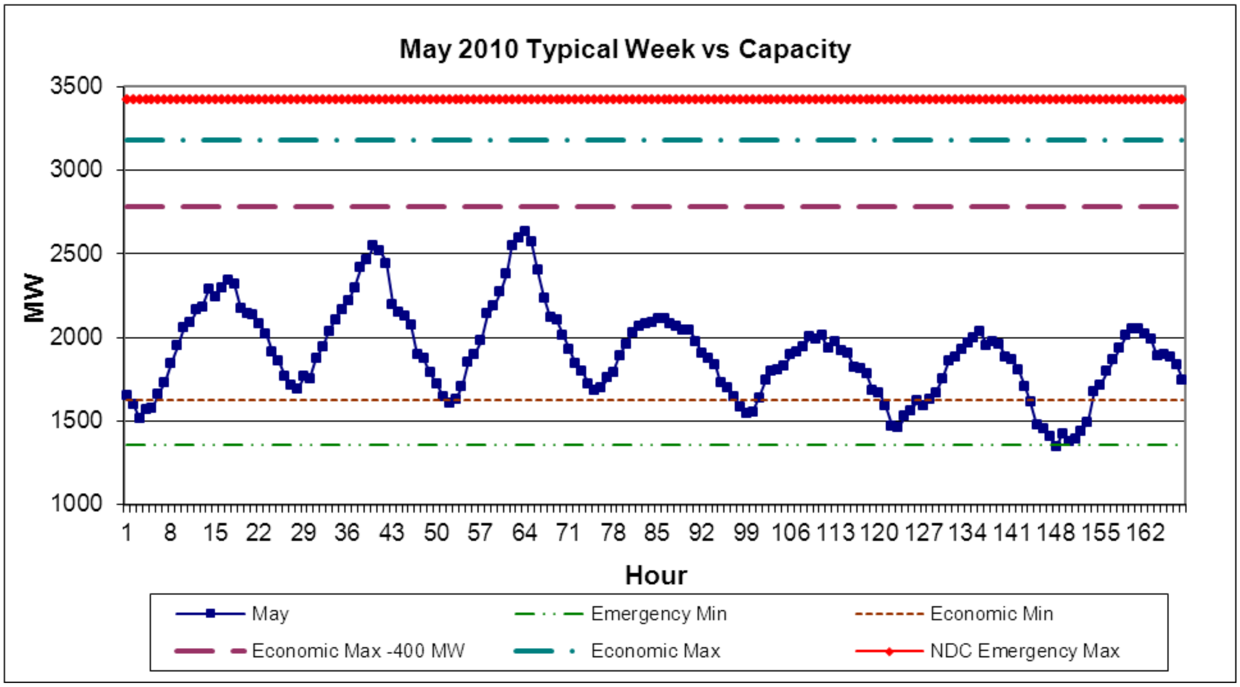
Note: Second Level = First Economic Max - 400

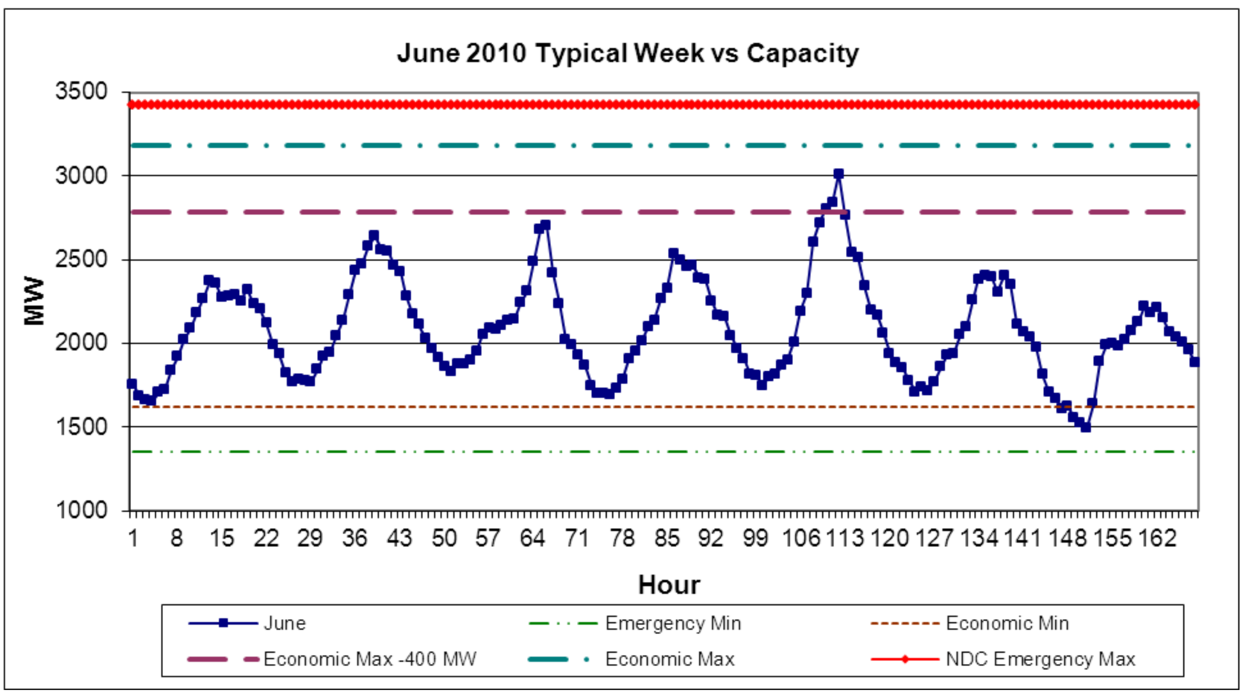

January 2010 Typical Week vs Capacity
MW
3500
3000
2500
2000
1500
1000
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
Hour
January
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max

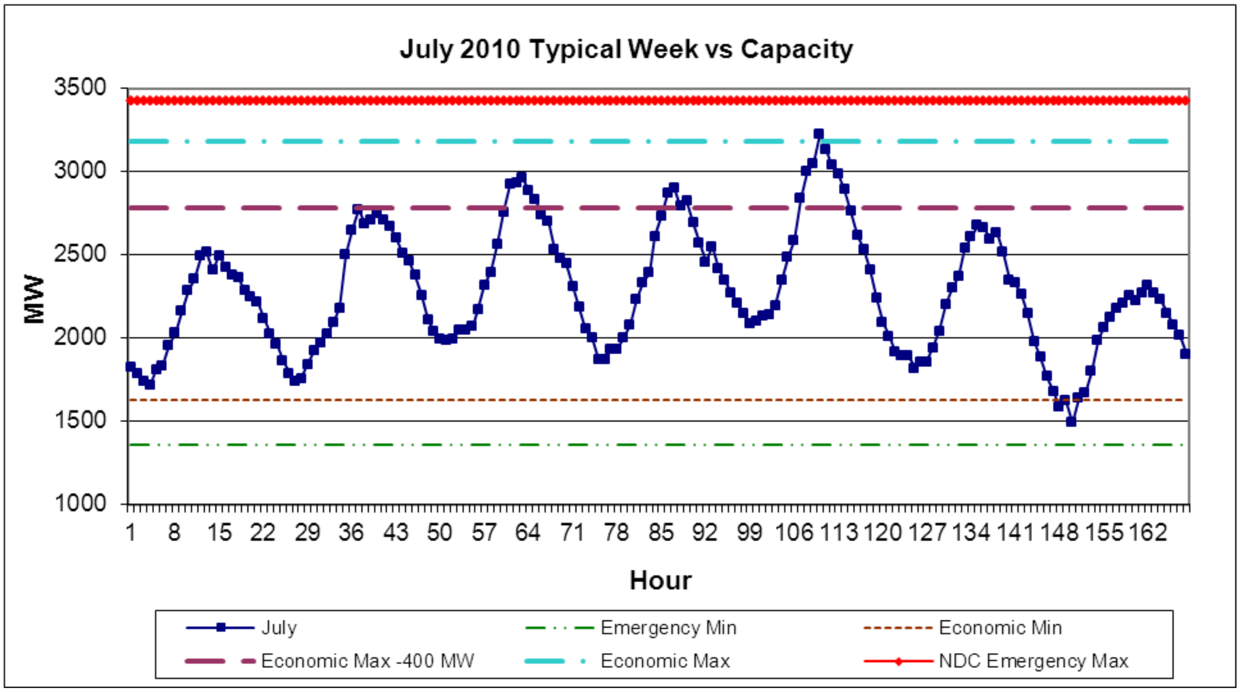

February 2010 Typical Week vs Capacity
MW
3500
3000
2500
2000
1500
1000
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
Hour
February
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max

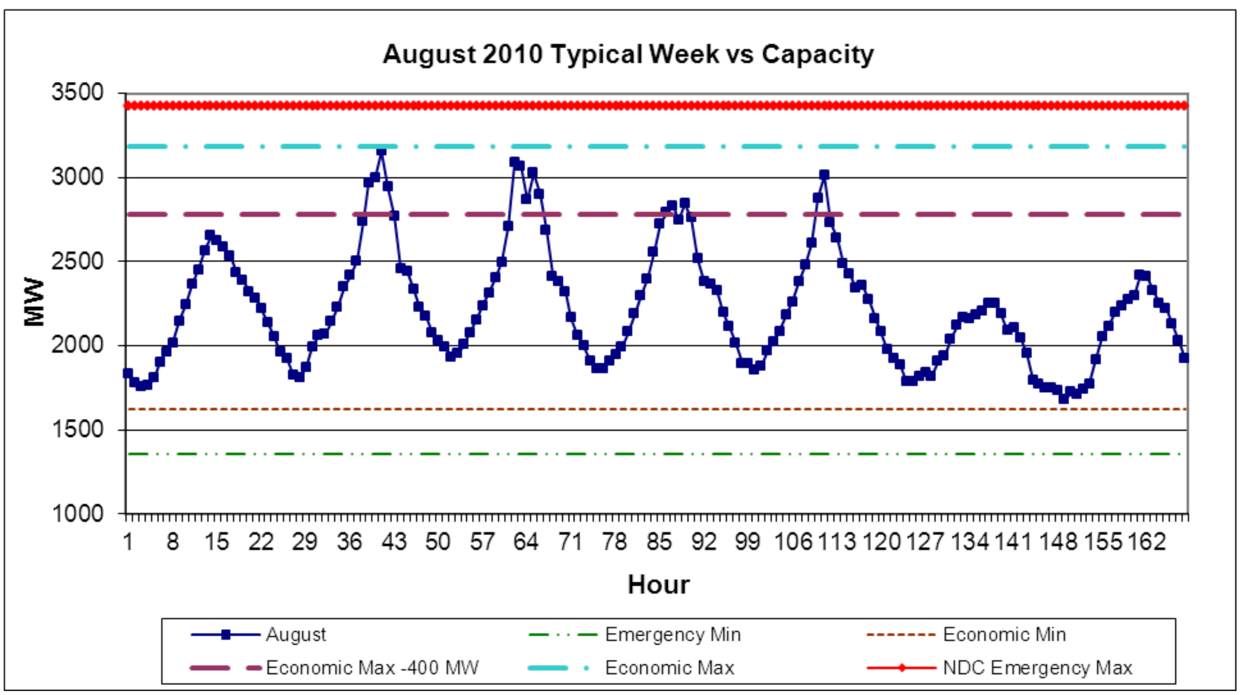

March 2010 Typical Week vs Capacity
MW
3500
3000
2500
2000
1500
1000
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
Hour
March
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max

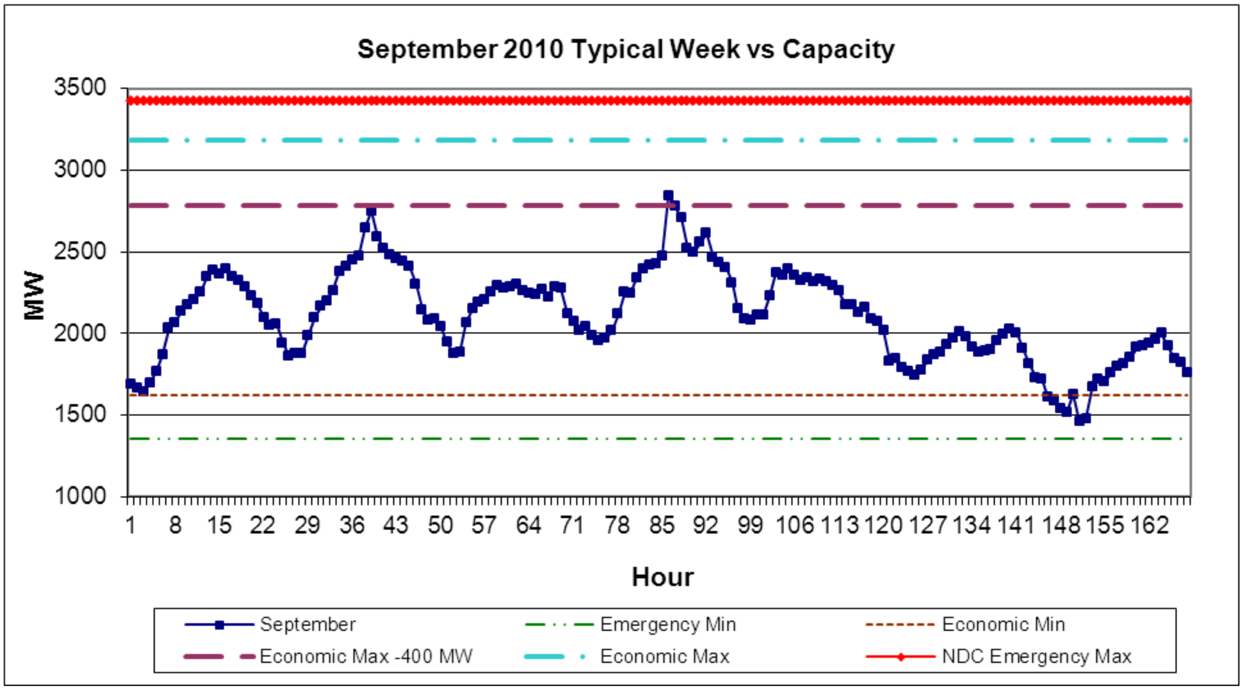

April 2010 Typical Week vs Capacity
MW
3500
3000
2500
2000
1500
1000
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
Hour
April
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max

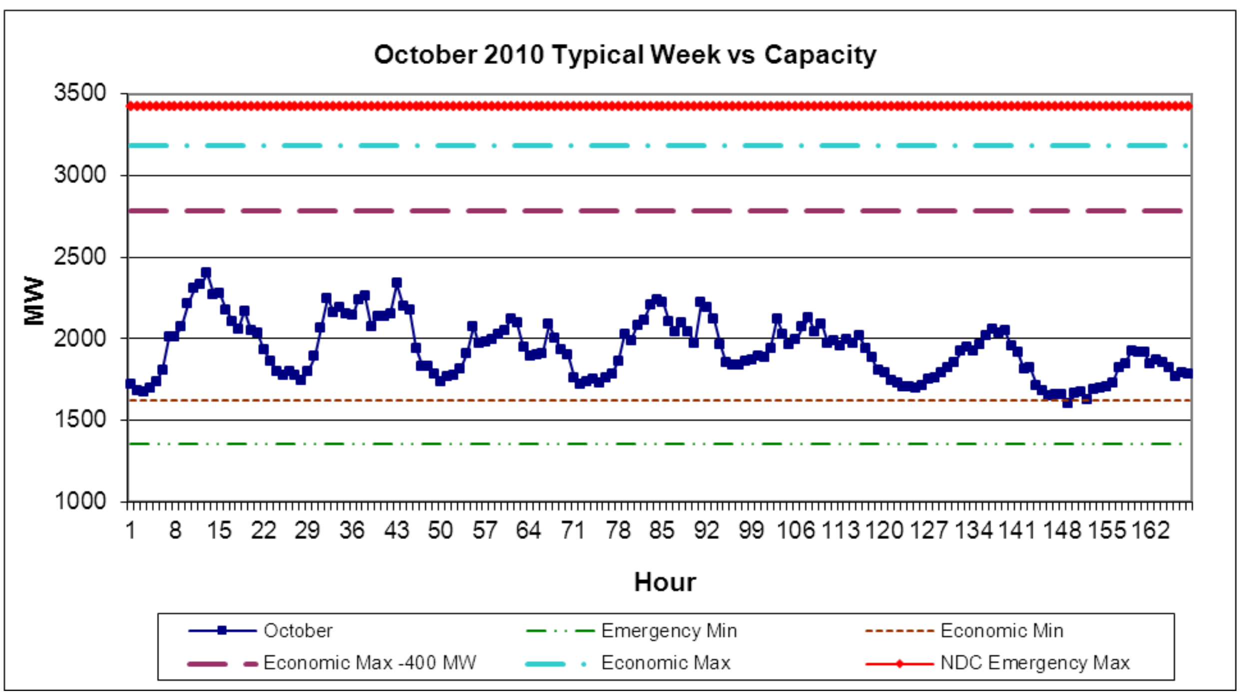

May 2010 Typical Week vs Capacity
3500
3000
2500
2000
1500
1000
MW
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
Hour
May
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max

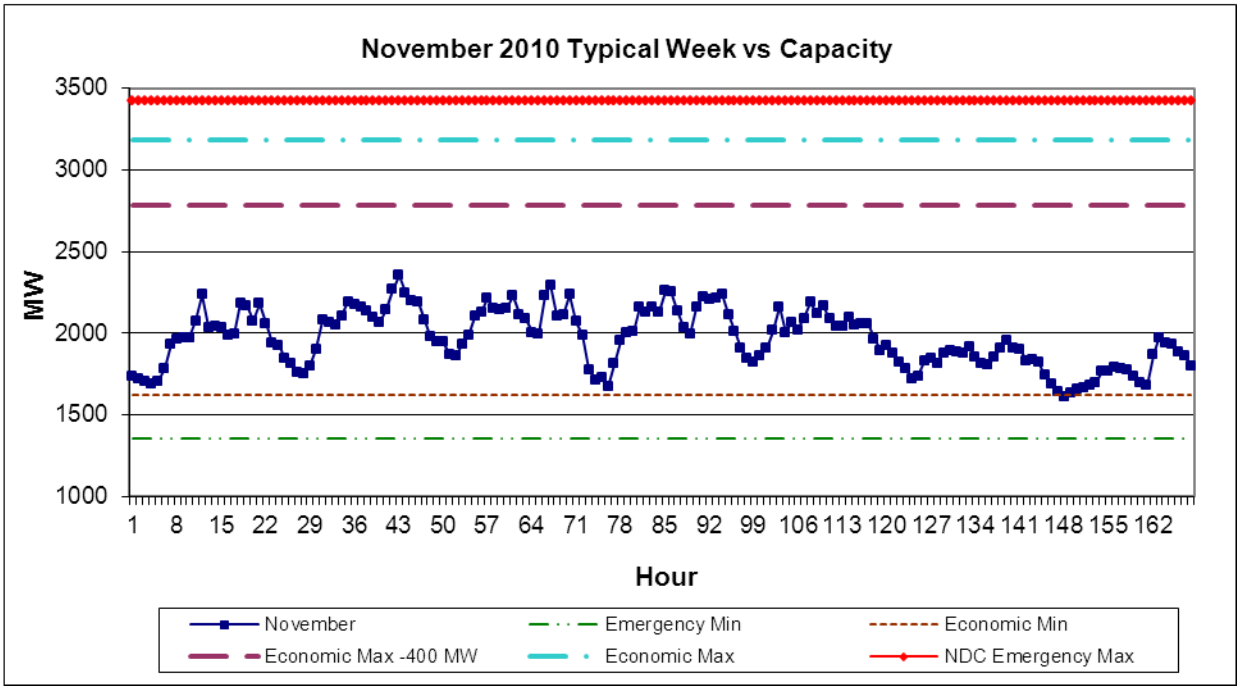

June 2010 Typical Week vs Capacity
3500
3000
2500
2000
1500
1000
MW
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
Hour
June
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max

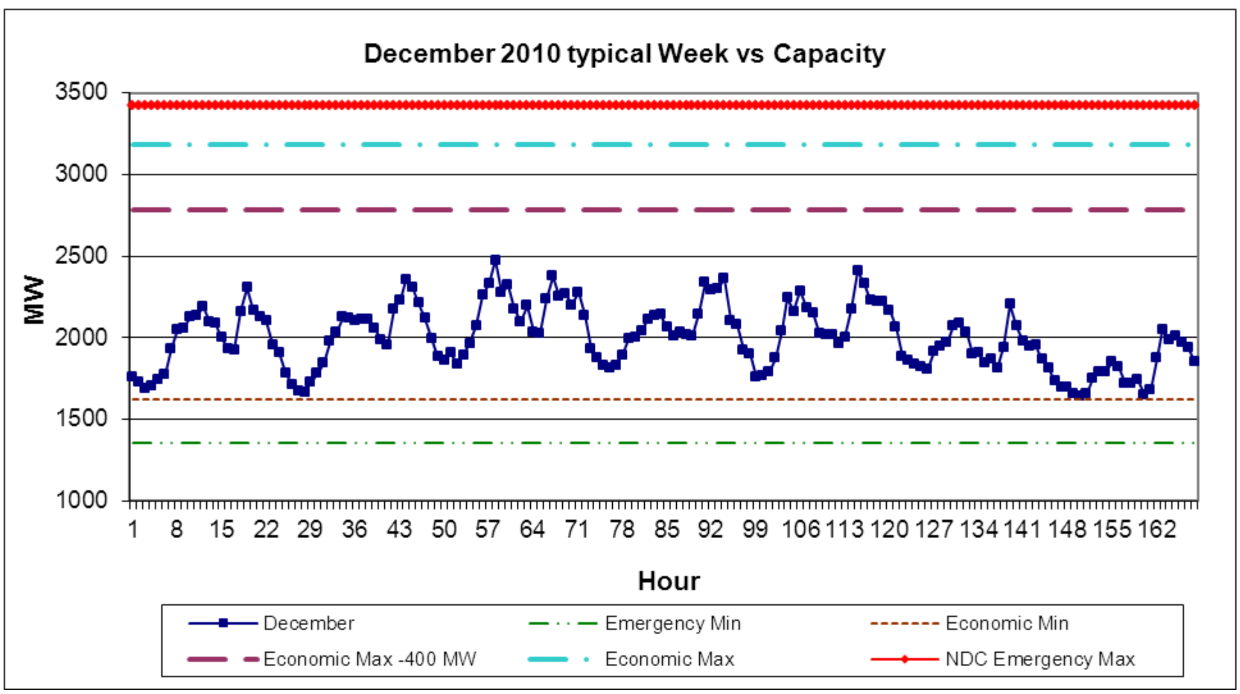

July 2010 Typical Week vs Capacity
3500
3000
2500
2000
1500
1000
MW
1
8
15
22
29
36
43
50
57
64
71
78
85
92
99
106
113
120
127
134
141
148
155
162
Hour
July
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max


August 2010 Typical Week vs Capacity
3500
3000
2500
2000
1500
1000
MW
1
8
15
22
29
36
43
50
57
64
71
78
85
92
99
106
113
120
127
134
141
148
155
162
Hour
August
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max


September 2010 Typical Week vs Capacity
MW
3500
3000
2500
2000
1500
1000
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
Hour
September
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max


October 2010 Typical Week vs Capacity
MW
3500
3000
2500
2000
1500
1000
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
Hour
October
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max


November 2010 Typical Week vs Capacity
MW
3500
3000
2500
2000
1500
1000
1
8
15
22
29
36
43
50
57
64
71
78
85
92
99
106
113
120
127
134
141
148
155
162
Hour
November
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max


December 2010 typical Week vs Capacity
MW
3500
3000
2500
2000
1500
1000
1
8
15
22
29
36
43
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64
71
78
85
92
99
106
113
120
127
134
141
148
155
162
Hour
December
Emergency Min
Economic Min
Economic Max -400 MW
Economic Max
NDC Emergency Max

Overview

Strategist®, a computer software system developed by Ventyx, LLC, supports electric utility decision analysis and corporate strategic planning. The system combines quality planning software, a proven track record, Ventyx's commitment to ongoing maintenance and support, comprehensive user documentation (online help), and fast response to client needs. Strategist® is available as a demand-side management analysis system, as a least cost resource optimization system, as a comprehensive planning tool for quick evaluation of hundreds of alternatives, as a finance and rates planning system and as selected application modules that complement planning capabilities already in place. Strategist® consists of the following application modules:

- Load Forecast Adjustment (LFA)
- Generation and Fuel (GAF)
- PROVIEW (PRV)
- Capital Expenditure and Recovery (CER)
- Differential Cost Effectiveness COST (DCE)
- Dynamic Marketing Program Design (DPD)
- Financial Reporting and Analysis (FIR)
- Class Revenue (CRM)
- Holding Company (HCM)

Strategist®: Evolution of the Industry Leader

Strategist® is fully supported by the technical and consulting services of Ventyx, LLC. Strategist® is an evolving product, enhanced and upgraded continuously.

Strategist®'s development since 1982 (originally known as PROSCREEN II) has proceeded in lockstep with that of the industry. In its earliest versions, PROSCREEN II was well suited for engineering, economic, and rudimentary financial analysis of central generating station alternatives. It was a major advance from then prevailing practices because financial consequences and constraints of resource decisions were an integral part of analysis. This advance allowed utilities to make the difficult decisions to cancel nuclear units or postpone base load additions on the basis of severe financial risk and strain.

In the early 1980's, PROSCREEN II added a comprehensive and integrated financial model, to represent the creative financing methods utilities required when faced with the period's record-high interest rates.

In response to the competitive pressures many utilities faced in the 1980's, PROSCREEN II incorporated dynamic cost allocation and class-by-class revenue analysis capabilities.

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In the late 1980's, Ventyx's optimization experts developed PROVIEW, adding the ability to simultaneously optimize supply and demand-side alternatives, a major step forward in integrated resource planning.

To address the industry need for fast, dynamic evaluation of demand-side management (DSM) measures, Ventyx added Differential Cost Effectiveness Module (DCE), a dynamic and detailed DSM analysis tool. Recent DCE enhancements have made it a powerful tool in the new, competitive utility environment. These include differential financial results, useful in customer profitability and retention analysis, and periodic avoided cost reporting, for determining how a utility's energy and capacity costs vary by time of day and season.

In 1990, PROSCREEN II's Generation and Fuel Module was enhanced by the addition of emissions reporting and dispatch, allowing full evaluation of compliance planning strategies. Ventyx added the Network Economy Interchange capability to PROSCREEN II to help utilities address the new issues related to competition. And as utilities approach a competitive industry and consider restructuring options, PROSCREEN II's Holding Company Module simplifies and automates the evaluation of regulated and non-regulated Strategic Business Units (SBUs).

The PROSCREEN II User Interface (UI) was introduced to PC users in early 1992 addressing the industry need to evaluate and present the results of many options under numerous conditions in a quick and organized manner. The Strategist® User Interface (UI) was unveiled in 1999 to provide for easier data input, organization, and reporting. The Windows-like feel of the interface allows users to quickly link data directly to Excel using Formula Service, organize and view data in Topics, and take advantage of customized reporting in Report Agent.

General Description

Strategist®'s advantage as an integrated planning system is its strength in all functional areas of utility planning. Strategist® allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Hourly chronological load patterns are recognized. Production cost simulations are comprehensive, yet fast.

Financial analyses are accurate and thorough. Rate-level determinations reflect each utility's customer class definition and cost-of-service allocation factors. The system employs dynamic programming to develop optimal portfolios of resources. Sophisticated screening methodologies are available to develop and refine strategic marketing initiatives, identify market potential, and build portfolios of initiatives.

In Strategist®, integrated resource screening and optimization is accomplished within a single system that handles strategic marketing programs, production costing, environmental reporting, capital budgeting, and financial, tax, and revenue forecasts on a rate class basis. Using a single, integrated software system for demand- and supply-side analysis of all resource types makes these studies much more manageable, ensures consistency in data assumptions, and provides credible, auditable results.

With Strategist®, utility management can examine many more options in a shorter period of time. The system has been designed to streamline the many steps in a comprehensive integrated planning effort and to handle the mechanics. This minimizes human error, inconsistencies, and repetitive data entry. For instance, if a combustion turbine's in-service date is delayed in the optimization program, the new in-service date is automatically specified to the production costing module as well as the capital budgeting and financial modules. The module also performs year-by-year "round robin" processing in order to appropriately address price elasticity.

Strategist® provides a wide variety of standard reports ranging from unit by unit generating statistics to construction project accounting reports to comprehensive pro forma financial results. The system includes full input summaries and detailed diagnostics.

Load Forecast Adjustment (LFA)

The Load Forecast Adjustment (LFA) Module is a multi-purpose tool for creating and modifying load forecasts and evaluating marketing and conservation programs. Using the LFA, a strategic planner may address key issues related to future electricity or gas demand and impacts attributed to each customer group. Results from this analysis can be automatically transferred to other Strategist® modules to determine production costs, system reliability, cost-effectiveness of marketing initiatives, financing and revenue requirements, and a variety of other indicators affected by loads.

Because availability of load data is often limited, the LFA is designed to process data at the level of detail readily available. Load data is processed in the LFA by user-defined load groups. It is possible to define these load groups as very detailed or very summary in scope. The LFA categorizes group data based on availability of hourly load shapes. Customer groups for which shapes are not available are processed differently than those with shapes.

A key feature of the LFA is its ability to accommodate different levels of detail for different categories of load. If load shapes are unavailable or not needed for some customer groups, the user can easily organize the data to allow the LFA to approximate the missing information. For example, a study which analyzes the loss of a large industrial customer may need detailed modeling of only those rate classes affected by the reallocation of costs. Hourly load shapes could be entered for these classes, and the user need only enter peak, energy, and coincidence factors for any remaining classes.

The analysis of programs which lack historic data, such as new demand-side technologies, will also benefit from the LFA's unique features. For example, a relamping program may be quickly modeled with estimates of energy savings per customer and reductions in peak demand. The model then schedules the hourly impact of these programs based upon optional rules specified by the user. Conversely, the evaluation of programs such as direct control of end-use loads (DLC hardware) can be based on more detailed data such as estimated net changes in seasonal demand, energy, and hourly customer shapes.

The LFA Module calculates the impact of changing prices on the initial forecast. When processing in round robin mode, the modified load forecast is passed to the Generation and Fuel (GAF) Module for production costing and to the Financial Reporting and Analysis (FIR) Module for financial analysis. The new electric prices developed in the FIR are then used for further price impacts in subsequent years of the Strategist® simulation.

The LFA Module may be used in conjunction with the Differential Cost Effectiveness (DCE) Module, PROVIEW and other Strategist® modules to evaluate marketing and conservation programs. The recommended process for evaluating these programs includes three separate stages: screening, integrated demand/supply optimization, and detailed analysis. The process can be likened to a funnel, as depicted in Figure OV-2. The LFA Module plays an important role in each of these stages.

Screening of marketing initiatives is accomplished through use of the LFA Module in conjunction with the DCE and GAF Modules. Programs in the LFA Module database are evaluated one at a time and are ranked based on cost effectiveness measures from the following perspectives: utility, participant, community (total resource), society, typical consumer (RIM), and any user-defined benefit/cost measures. Capacity deferral costs or benefits are calculated using the capacity credit logic in the LFA and/or the reliability/reserve margin equalization logic in the GAF. Energy benefits or costs are calculated with a separate GAF production cost run for each program.

The cost effectiveness measures calculated in the initial screening of marketing alternatives will result in a multi-objective decision space. DCE pivots off this accumulated information and develops packages of alternatives which may be used as discrete levels of investment, energy, or peak demand impact that may compete against supply-side options in a fully integrated resource optimization.

Integrated optimization of marketing programs may be accomplished by the LFA Module in conjunction with the GAF Module and PROVIEW. LFA load groups representing marketing initiatives are identified as explicit options in PROVIEW along with supply options. The optimal mix of demand and supply options is developed using PROVIEW's dynamic programming capability. Several load groups may be easily combined into a single PROVIEW alternative if desired. In addition to the optimal plan, PROVIEW develops multiple suboptimal portfolios for further analysis.

The user also has available the same inputs to examine alternate marketing program penetrations. These "penetration factor" inputs make it easy to examine in detail the production, financial, and rate impacts of specific programs.

General Capabilities

- The module provides a comprehensive demand-side program evaluation capability, with inputs for program cost, load impact, timing, and capital costs.
- Load impacts may be input chronologically for each program, or may be determined by the module based on inputs for peak, energy, and program type.
- The module, in conjunction with the GAF Module, provides for the dispatch of Direct Load Control (DLC). The module develops the data for DLC, including the characteristics of the underlying load to be controlled, the contribution of the DLC capacity to system reserves, the minimum savings required before DLC is dispatched economically, and the constraints to DLC operation. DLC is dispatched in the GAF according to an economic decision rule both to reduce peak and to maintain reliability.

- Load shape data may be supplied in detail if data is available or at an aggregate level for those groups which do not have adequate load shape data. The LFA Module thus allows the user to quickly develop a load shape projection for the company and system total, but gradually expand the detail of modeling as data availability increases.
- Load data can be defined in varying levels of detail. The degree of data aggregation is determined by the user. Any number of data "groups" may be specified. Data groups are summed to "class" totals. Class totals are summed to company totals. Data groups may correspond to end-uses, rate categories, customer categories, class totals, or even company totals.
- MWH data may be input seasonally or annually. If the user desires, the MWH for each season may be specified as a percent of the annual value. Peak load in MW or as a load factor may be input. If peak loads are not input for a group, peak is determined from input load profiles.
- End-use or DSM load shapes are determined from a variety of input formats. The user may enter a typical week profile directly for each season; enter typical daily load shapes and the frequency that each load shape occurs; or enter typical weekday, weekend day, and peak day load profiles. An EEI format preprocessor is part of the system. DSM programs can be specified as load impact "after" the program or as a combined "before and after" input.
- Class load profiles are computed to determine class peak and company load profile and peak demand.
- Most calculations are performed seasonally, where seasons are defined by the number of seasons and number of days in each season.
- The module provides a mechanism to reconcile the electric price assumption underlying the load forecast and the electric price resulting from the Strategist® simulation. This mechanism is intended to reflect a company's existing load forecasting process.
- Price response can be specified in a flexible manner. The LFA Module allows a variable lag structure input with lag coefficients specified for as many as ten prior years.
- Block energy rates, block demand rates, time of use rates, seasonal demand rates, and seasonal customer rates can be modeled to determine revenue by load class. These revenue values are passed to the DPD module and the FIR module.
- Results are reported by end-use group, by class, and by company.
- Numerous diagnostics supplement the standard reports.

Module Methodology

The LFA Module allows the user to create electric company load forecasts to be transferred to the GAF Module for production costing purposes. The LFA processes the components of company load at a class and group level, where load groups sum to load classes and load classes sum to total company load. The contribution of class loads to company load also provides important transfer information for use in the Class Revenue Module (CRM) of Strategist®. In addition to the company load and class transfers, the

LFA provides estimates of total marketing program costs and customer costs for use in the CER, FIR, and PROVIEW Modules.

Company peak, energy, and load shape are developed for each season defined in the Strategist® database. Seasons are identified by the number of days in each season. A user-defined number of seasons may be modeled, the maximum being defined at the time of the Strategist® delivery. Each season's load shape is represented by a chronological 168-hour load profile called a typical weekly profile.

Data is entered at the group level and consists of a seasonal forecast of non-coincident peak, sales, and a typical weekly shape. This shape may be input as a typical week or the profile can be built from a library of typical daily load shapes; or the profile can be built from a library of typical weekdays, weekend days, and peak days; or this profile may be processed from EEI data.

Costs (benefits) associated with marketing initiatives may be provided explicitly for each program, including fixed, variable and one-time implementation costs (benefits) for both the utility as well as the customer. The following marketing program expenses, customer costs and benefits may be modeled:

- Customer Fixed Costs
- New Participants One-Time Costs
- Customer Variable Costs
- Utility Fixed Expense
- Utility New Participants Expense
- Utility Variable Expense
- New Participants Incentive Payment
- Variable Incentive Payment
- Fuel Switch Savings (Costs)
- New Participants External Costs (Benefits)
- Variable External Costs (Benefits)

The shape impacts of marketing programs may be specified or a variety of automated system load inputs may be specified. Automated inputs include:

- Peak Shave
- Unscheduled Reduction
- Peak Build
- Unscheduled Build
- Valley Build
- Valley Shave
- Percent Conservation
- Percent Growth

Dispatchable direct load control (DLC) programs may be evaluated in conjunction with the GAF Module. Strategist®'s DLC algorithm links the LFA and GAF Modules allowing dispatch decisions for DLC to benefit from the commitment, outage, and cost information available in the generating unit logic while retaining the chronology of load information. Loads available for control are developed in the LFA as well as a number of inputs associated with the description of payback and contractual use limitations (daily, monthly, and yearly for both hours and events). Each load group with load available for control is passed to the production costing module and evaluated against the expected marginal operating costs that would be experienced had no load control been available.

The LFA Module first develops energy sales and peak demand for each load group by multiplying the inputs by a user-defined penetration factor (less persistence) and by adjusting for price elasticity impacts. For groups which have shape data input, the LFA compares the load factor of the group shape to the implied load factor in the group peak and sales forecast. Any discrepancy is eliminated by modifying the load profile. Finally, the module develops the group requirements shape by scaling the sales shape by the user input group loss factor for the season.

Once each group has been processed, the hourly profiles are summed to create class load profiles and the class profiles are in turn summed to produce total company loads which are transferred to the GAF Module.

In many instances, peak, energy, and profile data requirements cannot be obtained for every load group represented in the database. In such cases the module will allow the following combinations of minimum data inputs:

1. Load shape and sales forecast: Non-coincident peak will be calculated by fitting the given energy under the given shape.
2. Load shape and non-coincident peak: Sales will be developed for each hour by multiplying the normalized shape against the input peak.

In the event that an hourly profile is unavailable for an input load group, the user has the ability to input peak, sales, and a coincidence factor for the load group. The user must also input an aggregate company shape representing the load profile of all groups for which hourly profile data is not entered, plus any other groups with hourly profile data which the user may wish to include in the aggregate shape. The module will first process all groups and classes which are included in the aggregate shape and which have a defined load shape. It will subtract the sum of these given load profiles from the input aggregate load profile. The resulting "residual" shape is assumed to be associated with all of the load groups for which shape information was not provided.

The LFA user also has the option of having the model calculate the impact of changing prices on the initial load forecast. This is accomplished by having the user input the base prices assumed in the initial load forecast, as well as the peak and energy elasticity coefficients for each load group modeled. Elasticity can be performed at either the average system price level or at the load class level with the alternate prices either being input directly by the user or being transferred from the FIR/CRM Module. The latter option requires the use of the round robin processing methodology.

When calculating the impacts of price elasticity, the LFA evaluates the impact of changing price on each individual load group before summing the modified profiles to the class and company level. Only the adjusted load is passed on to the GAF Module.

For combination electric and gas utilities that use Class Revenue, the gas sales forecast may be housed in the LFA Module for later use in the classification, allocation and revenue requirement calculations.

Generation and Fuel (GAF)

The Generation and Fuel (GAF) Module simulates power system operation using proven probabilistic methods. It provides production costs and generation reliability measures that are essential to supply and demand planning. The GAF Module fulfills a strategic planning role in that it requires less computer resources than more detailed production costing modules, without sacrificing overall accuracy.

General Capabilities

- The GAF Module uses probabilistic production costing techniques to simulate the effects of forced outages.
- Most module calculations are performed seasonally, where seasons are defined by number of seasons and by number of days per season.
- Sales, purchases, and hydro generation are accounted for on a seasonal basis.
- The user can explicitly define an hour-by-hour schedule for a transaction or simply specify when the transaction tends to occur (during peak load hours, low load hours, or randomly) and the GAF will schedule the transaction appropriately.
- Thermal generating units are represented by capacity segments; each segment may have a distinct heat rate, which may be input as average, incremental, or coefficients of a quadratic input/output equation. Availability is defined for the entire unit; a partial availability may also be input to represent times when a unit may only operate at minimum capacity. The units which are classified as must-run are committed first, followed by enough other units to satisfy a user-input commitment criterion. The remaining units are committed on an economic start-up and dispatch basis, subject to fuel limits and spinning reserve requirements.
- The dispatch of thermal units and economy energy may be performed on a seasonal or annual basis.
- Pumped hydro projects and direct load control programs are economically dispatched on a seasonal basis, based on marginal cost.
- Units are dispatched to conform to upper and lower limitations on fuel usage.
- Unit dispatch is performed on an 'as burned' or replacement cost of fuel basis.
- Unit, company and system emissions are calculated based on actual runtimes and fuel usage. Emissions allowances are purchased or sold on the basis of system performance and the inputs for allowance cost and allowance base for each effluent. The cost of allowances is reflected in the dispatch lambda used in dispatch order decisions.
- Environmental externalities are calculated for emissions, emergency energy, and direct load control.
- Multi-company dispatch with interchange accounting for holding companies or power pool simulation is provided.
- Numerous diagnostic reports which document detailed calculations are provided.

Production Costing Methodology

The production costing procedure consists of two stages. In the first stage, the operation of hydro generation and sale and purchase transactions are simulated. The pumped storage facilities and direct load control programs are then economically dispatched based on the constructed marginal cost curve of the system. The result of this first stage is the remaining annual or seasonal thermal load duration curve. In the second stage, the expected operation of the thermal generating units within the year is simulated by a probabilistic technique. The results are the production costs and system reliability indices.

Dispatch of Non-Thermal Resources

System load data is passed in the form of a typical 168-hour weekly load shape to the GAF from the LFA Module. Then, the dispatch of non-thermal resources is performed. The user may specify the order in which these resources are dispatched, or use the following default order:

1. The transactions (sales or purchases) that are input in the form of hourly values for each season are added to (in the case of sales) or subtracted from (in the case of purchases) the chronological load curves.

2. The transactions that are characterized by seasonal capacity and energy are scheduled. For each sale transaction, the user chooses whether the sale is a valley fill or peak build sale, or is to be applied uniformly to the load curves. For each purchase transaction, the user chooses whether the purchase is a peak shave or valley reduction purchase, or is to be applied uniformly to the load curves.

3. The hydro generating units are dispatched one at a time. Each hydro unit has a minimum (must-run) MW capacity, a maximum MW capacity, and a total energy (MWH) for the season. The remaining load, after steps 1 and 2, is first modified by subtracting from it the minimum hydro generation for every hour. The remaining hydro energy is used for peak shaving. This peak-shaving energy is calculated by subtracting the minimum hydro generation from the total hydro energy. The peak-shaving capacity is the difference between the maximum MW capacity and the minimum MW capacity of the unit.

4. Pumped storage hydro is scheduled. Storage dispatch is based on the expected generation cost at each hour before storage, pond storage limitations, cycle efficiency, and minimum savings. The storage algorithm works from highest cost hour down for generation and from lowest cost hour up for pumping, reducing the remaining load at high cost hours and increasing the load at low cost hours. This process is performed subject to the minimum savings and pond limit constraints. An option is available for the capacity of storage not used for economic reasons to be used for reliability purposes.

5. Direct load control devices are scheduled. The LFA Module provides information on underlying loads that are available for control and DLC dispatch parameters. All DLC devices are dispatched simultaneously so as to achieve the greatest possible savings and in such a way that a new peak is avoided. However, there is the added flexibility of defining a user-specified order in which the DLC devices will be dispatched. Payback is explicitly considered in addition to contractual constraints such as maximum number of interruptions and maximum hours of interruptions for each program.

If several companies are being modeled, non-thermal resources may be dispatched for a specified company or group of companies. This allows modeling of different types of systems such as a Genco and Disco where the generating company's non-thermal resources will be dispatched to meet the load of the distribution company. This type of logic is also useful for interconnected power systems where a resource should be scheduled based on market value in addition to native load requirements. After the dispatch of non-thermal resources is completed, the remaining load is served by thermal generating units. The thermal dispatch is performed on a seasonal or an annual basis as determined by the user for each water year. If annual dispatch is chosen, the modified seasonal load curves are combined into an annual load curve.

Dispatch of Thermal Resources

Each generating unit may be represented with up to seven capacity segments. Each capacity segment may have a distinct heat rate. A unit may be designated as a must-run unit, in which case its minimum segment is dispatched before any upper segment in the system. Other thermal unit inputs include commission date, retirement date, immature forced outage rate, mature forced outage rate, and partial forced outage rate at the minimum capacity level.

Planned maintenance may be explicitly modeled for each generating unit by specifying the start and end dates for each maintenance, or by entering a start date and number of weeks of maintenance in each year. Optionally, the annual number of weeks of maintenance may be specified, in which case maintenance is scheduled for the unit to levelize reserves or emergency energy across seasons. Maintenance may be handled as either a deration of the unit's capacity, or as an adjustment to its forced outage rate.

The widely accepted probabilistic production costing procedure is used to project the operation of each generating unit. The minimum segments of the must-run units are dispatched first, followed by enough other minimum segments to satisfy a user-defined dispatch commitment criterion. The remaining segments are dispatched in an economic order approximating the economic dispatch procedure of a system operator. Sufficient on-line capacity reserves are maintained to satisfy user-defined spinning reserve requirements. Fuel limits are monitored during the thermal unit dispatch. If fuel limits are exceeded, the system modifies the fuel mixtures and/or energy outputs of the generating units, resulting in a departure from economic dispatch. The impact of economy energy purchases and sales are determined on an economic basis.

After all available resources have been utilized, several reliability indices are determined. Among these are:

- Expected hours with negative margin (Loss of Load Hours, or LOLH)
- Expected emergency energy
- Reserve Margin

Alternatively, reliability measures, such as LOLH and expected emergency energy, may be fixed so that equivalent capacity benefits for DSM programs may be calculated. The GAF has the ability to calculate the equivalent capacity benefit of an incremental change in load based on a broad reliability measure. This relieves the user of the uncertain task of estimating a capacity benefit which for many DSM programs (e.g. direct load control) may be difficult to measure. This is a significant improvement over the traditional calculation of the impact on the reserve margin (peak hour impact).

Emissions are calculated each season on a unit-by-unit basis. Removal efficiency characteristics of each unit are input. The individual unit results are then aggregated into company and system emissions totals and rates. The cost of emissions, whether such cost is in the form of allowance purchase price, emissions tax, or emissions externalities result from the thermal dispatch. Separate inputs allow these emissions costs to be included in a unit's dispatch lambda if desired.

Network Economy Interchange (NEI)

The Network Economy Interchange (NEI) feature of the GAF helps reduce operating costs for a group of interconnected utilities by developing the most beneficial unit dispatch schedule for the group.

In a situation where there is unlimited transmission capacity between interconnected systems, the interchange process reaches economic equilibrium. At equilibrium, the marginal costs of all systems are virtually identical. To reach the point of equilibrium, the NEI feature performs interchange among interconnected systems in order to levelize the marginal costs. Interchange is economical as long as the difference in marginal cost is greater than the connection charges among systems.

In power systems, particularly large systems covering major geographical areas, unlimited transmission capacities seldom exist, due to physical or contractual transmission limits. To neglect transmission capacity limits is to overestimate the benefit of economy interchange. This problem may not be severe if transmission constraints are not binding. However, in transmission-poor systems, overestimation of economy interchange benefits may distort overall system production costs.

The NEI feature provides a marginal cost-based algorithm for economy interchange among connected systems, while considering losses on transmission lines and enforcing transmissions limits for all hours. NEI accomplishes this by systematically matching potential buyers and sellers and incrementally equalizing their marginal costs.

The billing and accounting logic of the Network Economy Interchange reflects the market clearing price of the system. Therefore, if there are no losses, no connection charges, and no tie constraints, the marginal cost of the buyer will equal the marginal cost of the seller and the energy generated will equal the energy received. If there are differences between the buyer's cost and seller's revenue, the losses or surplus revenue is split between them based on the transfer point. If a third party is involved, then the losses and surplus revenue are allocated to the buyer, seller, and/or third parties based on their ownership.

After all other load modifications are complete (transactions, hydro, pumped hydro, and direct load control), the GAF implements economy interchange. Interchange results are used to modify hourly loads of the internal companies. The GAF then executes the thermal dispatch for every internal company. If there is more than one internal company, the NEI feature sums company outputs to obtain the pool results.

PROVIEW (PRV)

The PROVIEW (PRV) Module is a resource planning model which determines the least-cost balanced demand and supply plan for a utility system under prescribed sets of constraints and assumptions. PROVIEW incorporates a wide variety of expansion planning parameters including alternative technologies, unit conversions, cogenerators, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan which would be best suited for the utility. PROVIEW works in concert with the GAF Module to simulate the operation of a utility system. PROVIEW's optimization logic then determines the cost and reliability effects of adding resources to the system or modifying the load through demand-side management (DSM) or marketing programs.

The module allows modeling of emissions-related constraints, emissions allowance trading, and emissions reduction alternatives (e.g. scrubbers, fuel switching). These capabilities are used both to develop optimal environmental compliance strategies and to incorporate resource planning.

Programs are screened by using the LFA Module in conjunction with DCE and the GAF Module. Programs in the LFA Module database are evaluated one at a time and are ranked based on industry standard cost effectiveness measures such as participant cost, utility cost, total resource cost, societal cost, and ratepayer impact measure (average rate). Groups of programs are then developed into portfolios based on the results of the ranking process. The LFA allows detailed treatment of system, class or end-use loads, enabling you to specify demand side or marketing programs on an hourly chronological basis. Capacity deferral benefits or costs are calculated using the capacity credit logic in the LFA and/or the reliability equalization logic in the GAF. Energy benefits or costs are calculated with a separate GAF production cost run for each program.

Once portfolios of programs have been developed, the LFA Module is used in conjunction with PROVIEW to perform integrated demand and supply optimization. LFA load groups representing DSM or marketing programs or portfolios of programs are specified as explicit PROVIEW alternatives. In this way, the programs compete on a "level playing field" with supply options. The optimal demand/supply plan is then developed using PROVIEW's dynamic programming capability. In addition to the optimal plan, PROVIEW retains multiple suboptimal demand/supply plans for further analysis.

The final step in evaluation of DSM or marketing programs involves use of the LFA Module in conjunction with all modules of Strategist®. The CER Module provides the annual capital expenditure impacts of the programs and allows assessment of program costs which are capitalized. The FIR Module allows the evaluation of the impact of the programs on average rates, rate increase requirements and timing, and financial performance. The impact of programs on class rates and cross subsidy issues may be thoroughly evaluated in the CRM.

General Capabilities

- Data input is structured in a similar manner to Strategist® GAF data.
- PROVIEW provides quick turn-around time by eliminating options that are not feasible and by eliminating unnecessary detail.
- PROVIEW allows for a full enumeration of all combinations of expansion options and/or demand-side management or marketing programs through its Dynamic Programming option. The system can thus be highly rigorous in its determination of a least-cost expansion plan for the entire planning period.
- Production cost calculations are performed for each alternative through the execution of the GAF Module. Demand side programs and associated sales impacts are computed through the execution of the LFA Module.
- PROVIEW uses the economic carrying charge as the capital cost representation during the study period optimization. After the study period rankings have been determined, the plans will be re-ranked over the planning period horizon using actual year by year revenue requirements. If these are not input, then levelized revenue requirements will be used.
- PROVIEW explicitly handles end effects in determination of the least cost plan. The end effects analysis approximates the capital and production cost of replacing the resulting utility system in kind over the user-input end effects period.
- PROVIEW provides for one of five objective functions to be used in the least-cost optimization: minimization of utility costs, minimization of average study period rates, minimization of total societal cost (total resource cost), minimization of total resource costs, or maximization of total unit profitability.
- PROVIEW will also evaluate any expansion plan optimized by one of the five objective functions mentioned above with regard to financial performance. The expansion plans may be re-ranked based on electric revenue, corporate value of the firm, economic value added, earnings per share, or value per share.
- PROVIEW provides numerous constraints for the user to reduce the number of options to consider. Minimum and maximum number to add, minimum and maximum reserve or loss of load hours, and first year available to add are but a few. PROVIEW can define alternatives as mutually exclusive or inclusive in a year. It can also restrict alternatives to be dependent upon certain other alternatives being in service (the second unit in a station is dependent upon the first unit having been constructed). PROVIEW also allows options such as phased construction of combined cycle units to be evaluated quickly. Maximum emissions levels can also be specified to reduce the alternatives considered.
- A PROVIEW optimization may be performed for the entire pool when multi-company summation logic is used. PROVIEW allows constraints to be entered at both the system level and for each company in the pool.

- When using Multi-Company, PROVIEW allows the addition of alternatives which are owned by a company other than the company (or pool) which is being optimized.
- PROVIEW allows complete evaluation of suboptimal plans. All plans are saved in PROVIEW's database for subsequent reporting and analysis. The user may specify the ranking of significantly different plans. Significantly different plans are developed as of a certain year of the analysis.
- Numerous diagnostics which explain in detail how PROVIEW reaches its optimal plan decision are available.
- PROVIEW results include a database that contains the results of all plans. The analyst can select any of these plans to be automatically set up in the LFA, GAF, CER, and FIR Modules for more extensive evaluation.

Module Inputs

PROVIEW requires the data supplied by the user to be separated into two sections: the first section characterizes the existing utility system and the other section characterizes the potential expansion or marketing initiative options. The existing utility system data set is composed of the Strategist® GAF and LFA Module data sets, which are fully described in the GAF Module online help and LFA Module online help. Briefly, data requirements for the existing system are grouped according to load, hydro unit, transaction, thermal unit, storage unit, fuel type, fuel class, and general parameter data. Data requirements for the existing load forecast are grouped according to load group, load shape, load class, and parameter data.

The data required for the planning alternative section contains information relating to alternative resources that may be added or marketing programs that may be implemented. Data in this section defines alternative unit characteristics, construction costs, resource addition limits, and resulting system reliability constraints. Alternative option information is specified in a general manner so that any proposed available option can be commissioned at any time during the study period.

Module Methodology

PROVIEW's Dynamic Programming calculations are summarized as follows:

1. A capital cost table is constructed. This table contains the economic carrying for every alternative for each year of the study.
2. Feasible current-year states (combinations of alternatives) are determined by examining every combination of user-defined resource additions or marketing programs. Feasible states are those which meet reliability dependency and tunnel constraints. One-year capital and production costs are calculated and used to determine the accumulated cost-to-date. Each feasible state description is saved along with the associated accumulated cost-to-date.
3. The module repeatedly analyzes and saves feasible states for each year during the planning period. At the end of this planning period, a matrix of possible states for

each year has been constructed. Note that each feasible state in the final year represents the end product of a different expansion plan.

4. Each potential expansion plan is subjected to end effects analysis. The end effects analysis adds to the accumulated cost-to-date of the capital and production cost of replacing the resulting utility system in kind, over a user-specified end effects period.
5. The module traces back through the matrix of feasible states to identify the components of the optimal plan and the components of each sub-optimal plan.
6. The optimal plan is set up in the LFA, GAF, CER, and FIR for subsequent analysis and reporting. All plans are saved in the database.

Capital Expenditure and Recovery (CER)

The Capital Expenditure and Recovery (CER) Module provides a method of readily comparing and evaluating the economics of generation alternatives. In addition, the CER Module, through its interaction with the Financial Reporting and Analysis (FIR) Module, allows the strategic planner to analyze the financial implications of an individual project or an entire construction program.

General Capabilities

- The CER Module allows the strategic planner to examine the financial effects on the company's consolidated operations of construction alternatives intended to meet the forecasted system demand. Complete economic evaluation reports using both minimum revenue requirements (MRR) and discounted cash flow techniques are available.
- The CER Module simulates the financial effects resulting from changes in the treatment of the tax effects of depreciation allowances for funds used during construction (AFUDC).
- Any number of major projects (those which close to plant at the end of the expenditure stream) and blanket projects (those which close to plant as expenditures are made) can be evaluated. Highly flexible logic allows users to specify close to plant amounts for book and tax purposes on a project-by-project basis. DSM projects can be modeled to capitalize expenses associated with conservation programs.
- The CER provides for a convenient method of examining alternate plans. A project's in-service date may be changed with a single command. All annual expenditures for that project are automatically shifted, taking inflation and escalation rates into account.
- A variety of reports display results for individual projects, for user-defined aggregations of projects, and for the entire system.
- Project phase-ins and disallowances are easily analyzed. Through interaction with the FIR Module, the user may examine the rate and financial impacts of alternative regulatory treatment of canceled or partially canceled projects.
- The CER Module allows for a project-to-GAF-unit tie. Fuel cost and O&M expense can then be passed to the CER by project for use in its revenue requirements calculations. The CER, if desired, will also use the GAF unit's commission date as the project in-service date. Thus, unit slippage can be assessed in both the GAF and CER with only one data change.
- Using the project-to-GAF-unit tie, the PROVIEW Module will output a CER database for the selected plan containing the appropriate in-service dates for expansion units.

Accounting, Tax, and Economic Calculations

The accounting and tax calculations are separated into three stages: construction period calculations, in-service date (close to plant) calculations, and service life calculations. The module is run for the number of years specified by the user. However, construction and commercial operation may start at any time during a year, and all calculations will be adjusted accordingly.

Construction Period Calculations

The construction period begins with the construction start date and ends immediately before the in-service date. Items calculated for this period include:

- Capital Expenditures - These are entered either as annual amounts in constant base year dollars or as nominal dollars. If desired, a total dollar amount to be spent can be input, along with an S-curve to distribute the expenditures over an appropriate range of years. Individual project escalation rates may be specified, as well as a general inflation rate applicable to all capital costs. For a blanket project, the user can input annual percentages or dollar amounts of expenditures to be closed to plant. These amounts can vary for book and tax purposes.
- Construction Work In Progress (CWIP) - Capital expenditures and AFUDC are added to this account each year during construction.
- CWIP in Rate Base - This value is calculated by multiplying a user-specified percentage of CWIP in the rate base for each project in each year by the amount of construction work in progress.
- AFUDC - The balance of CWIP less cumulative AFUDC is multiplied by the eligible percentage and the AFUDC rate to compute the AFUDC for the current year. If the user elects to compound AFUDC, the entire CWIP balance can be used in this calculation.
- Overheads - If desired, capitalized overheads are deducted for tax purposes during the construction period but are capitalized for financial reporting purposes.

In-Service Date Calculations

For major projects, the CWIP balance is closed to plant at the end of the in-service date. This includes any expenditures and AFUDC for the current year. Closing is assumed to take place on the last day of the in-service month. For major projects with expenditures after the in-service date, expenditures are closed to plant in the year they are made. For blanket projects, amounts are closed in the years following their expenditure according to a user-input schedule. This schedule can be specified as either percentage or dollar amounts, and can vary for book and tax purposes for the same project.

Service Life Calculations

In each year after a project has been closed to plant, the following calculations are made for that project:

- Book Depreciation - Book basis is the total amount closed to plant, including AFUDC. Depreciation can be calculated using any of the methods available for calculating tax depreciation, although the straight-line method is the default.
- Tax Depreciation - Tax basis is the amount closed to plant less any AFUDC included in the closed to plant amount and less any capitalized overheads which have already been deducted for tax purposes. One of twelve depreciation methods may be used. They are:

Double Declining Balance (DDB)
Straight Line (SL)
Sum of the Years Digit (SYD)
DDB switching to SL
SYD switching to SL
DDB switching to SYD and SL
User Specified Percentage
150% Declining Balance switching to SL
150% Declining Balance
Units of Production
Do Not Calculate Depreciation

Tax depreciation for the first in-service year is calculated using one of four methods: fraction of the year, half-year convention, modified half-year convention, or mid-quarter convention.

- Tax and Insurance Cost - User-specified rates for property taxes, other taxes, and insurance costs are applied to the amount closed to plant excluding AFUDC.

- Nuclear Fuel - The GAF Module provides annual fuel burn and fuel cost for each nuclear unit. The CER Module calculates the capital expenditures using the annual nuclear fuel burn from the GAF Module for either a single nuclear fuel project or multiple nuclear fuel projects. Book depreciation is equal to nuclear fuel cost in each year and tax depreciation is calculated using the project capital expenditures and the plant closing schedule. DOE nuclear waste disposal costs may be modeled.

- Decommissioning Costs - The CER Module accounts for the practice of recovering an estimate of decommissioning costs over the life of the plant.

Economic Calculations

The CER Module also calculates the annual present worth and the accumulated present worth of the revenue requirements associated with each project. Reports show the determination of present worth of revenue requirements using both a minimum revenue requirements and a discounted cash flow approach. This enables the CER Module to be used for engineering economic evaluations of specific projects, including life-cycle economic comparisons of alternative projects.

System analysis reports are also available for investigation of the revenue requirements for an entire plan, including fuel and O&M as transferred from the GAF Module.

The CER also evaluates capital projects within an unregulated, competitive environment. Using the unit profitability features in the GAF, the CER determines revenue for a project based on energy, capacity, and ancillary revenue. Operating and capital expenditures are subtracted from the revenue to determine total operating income. Profitability reports show this information at the project, project class, and system level. An internal rate of return is also calculated for each project based on annual net cash income versus construction expenditures.

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NIPSCO

Part 1. Identification and Certification

Transmitting Utility Name and Address:

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Merrillville, IN 46410

Contact Person:

Dawn Quick
Transmission Planning Engineer
Electric System Planning Department
Telephone Number: 219-647-4220
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Certification and signature by an authorized official of the Transmitting Utility regarding the accuracy of the information submitted:

____

Mary Ann Groszek
Manager, Planning Support

<u>Revised Process For Public Access to Copies of This Report (Effective October 10, 2001):</u>
Requests for copies of this report should be submitted in writing to the FERC, Form No. 715, 888 First St. N.E., Washington, DC 20426. Requests will follow Freedom of Information ACT (FOIA) protocols as set forth in 18 C.F.R. § 388.108.

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Part 4. Transmission Planning Reliability Criteria

This document provides the reliability criteria used to assess and test the strength and limits of Northern Indiana Public Service Company's (NIPSCO) transmission system to meet its load responsibility as well as to move bulk power between and among other electric systems. It is the transmission system's responsibility to adequately serve and support distribution, local, and wholesale customer loads in an efficient, cost effective manner. It should also be able to withstand reasonable disturbances on the bulk power system. This document may be revised in response to new system conditions, safety issues, customer requests, regulatory requirements, or NERC requirements.

The planning criteria are listed under the following categories:
1) System performance criteria
2) Facility rating criteria
3) Model building criteria

4.1 System Performance Criteria

4.1.1 Steady State Performance Criteria

NIPSCO Transmission Planning conforms to all applicable NERC standards. In 2008, NIPSCO was found to be in full compliance with all NERC TPL standards under audit. System performance assessments are conducted at least annually over a reasonable range of future scenarios. Unless otherwise stated, the following conditions are tested over the near-term (years one through five) and longer-term (years six through ten) planning horizons.

A. Normal Conditions

- System is at normal operational status; all components of the system are in the state as designed.

- Loading on every transmission element is within its acceptable normal rating. Normal rating is defined as the ampacity, voltage, or power limit at which a system component can be continuously loaded without reduction in expected service life.

- Voltage on all buses is within its acceptable range. The acceptable voltage range is 92 percent to 105 percent of nominal voltage for all buses operating at 138 kV and above. Due to wider voltage swings and the lack of voltage regulation at customer substations, minimum acceptable 69 kV system voltage is set at 94 percent of nominal voltage.

- NIPSCO 138 kV customer substation buses are monitored at the Midwest ISO default voltage range of 95 percent to 105 percent of nominal voltage. Any deficiencies identified are communicated to the customer.

B. Loss of Single Element Conditions

- Loss of a single transmission line, transformer, or generator.
- Loading on every transmission element is within its acceptable emergency rating. Emergency rating is defined as the ampacity, voltage, or power limit at which a system component is allowed to be loaded over the normal rating. A specified amount of consecutive hours or cumulative period of time can be associated with the utilization of this rating.
- System adjustments are permitted to prepare for the next contingency, not for overload relief.
- The acceptable voltage range is 90 percent to 105 percent of nominal voltage for all buses operating at 138 kV and above. For the 69 kV system, minimum acceptable voltage is 92 percent of nominal.

C. Loss of Multiple Element Conditions

- Loss of two or more transmission elements.
- Loading on every transmission element is within its acceptable emergency rating. Automatic or controlled switching, generation re-dispatch, or firm service curtailments, as well as planned load loss, is permitted to maintain system control.
- The acceptable voltage range is 90 percent to 105 percent of nominal voltage for all buses operating at 138 kV and above. For the 69 kV system, minimum acceptable voltage is 92 percent of nominal. Automatic or controlled switching, generation re-dispatch, or firm service curtailments, as well as planned load loss, is permitted to restore proper voltage.

D. Extreme Event Resulting in Multiple Elements Out of Service

- Extreme events such as loss of all circuits on a right-of-way, loss of a substation, or loss of all generating units at a station are evaluated for risks and consequences.

- Studies may identify vulnerabilities on the system but are not required to have mitigation plans in the form of operating procedures or system additions.

4.1.2 Transient Stability Criteria

Generator stability is checked whenever there is a major change in system configuration involving existing generating stations or generator addition. When warranted, studies are performed to verify that generators do not experience instability under the following conditions:

- Permanent three phase fault on any system element, under normal fault clearing conditions and slow fault clearing conditions.

- Permanent single phase, two phase or three phase fault on any system element, with another system element out of service, under normal fault clearing conditions and slow fault clearing conditions.

4.1.3 Voltage Flicker

Dynamic voltage variation, or flicker, as a result of customer equipment operations is normally not significant on the transmission system. The infrequent and unavoidable fluctuations of short duration shall not be considered a violation of voltage criteria specified above (Section 4.1.1). However, customers shall abide by NIPSCO power quality standards when operating their equipment. NIPSCO power quality standard is based on the latest industry standards, ANSI/IEEE 519, ANSI/IEEE C57.110, ITIC Curve and IEEE/GE voltage flicker. A greater variation of voltage may be allowed where customers are widely scattered or the loads served do not justify close voltage regulation. Objectionable power quality conditions such as customer induced excessive voltage flicker, excessive voltage and current harmonics, when found, are normally relieved by working with the customer to bring power quality to an acceptable level. Remediation typically takes place through the addition of equipment (i.e., reactors, static var compensators, filter capacitors) and/or a change in customer operating characteristics. NIPSCO may refuse or disconnect service to customers for using electricity or equipment that adversely affects distribution or transmission service to other customers.

NIPSCO

4.2 Facility Rating Criteria

It is the responsibility of NIPSCO Transmission Planning to determine, update, and communicate facility ratings for reliable planning and operations of the Bulk electric system using established methodologies. This is consistent with NERC FAC Standards. Transmission Planning coordinates with NIPSCO Generation and neighboring utilities to develop Facility Ratings for jointly owned facilities.

The Facility Rating equals the most limiting applicable Equipment Rating of all the individual equipment components that comprise the Facility. The scope of equipment addressed includes, but is not limited to:

- transmission conductors
- transformers
- breakers
- current transformers
- potential transformers
- wave traps
- capacitors
- switches
- relay protective devices
- substation buses, cables, and terminal equipment

Manufacturers Nameplate ratings are used when relevant. Substation and Overhead conductor ratings are calculated using published industry standards and assumptions, such as IEEE.

Transmission Planning makes its Facility Ratings Methodology available for inspection and technical review to Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request. If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of NIPSCO's Facility Ratings Methodology, Transmission Planning provides a written response to that commenting entity within 45 calendar days of receipt of those comments. As required by NERC Standard FAC-009, the response will indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

NIPSCO

4.3 Model Building Criteria

As requested by the NERC Eastern Interconnection Reliability Assessment Group/Multiregional Modeling Working Group, NIPSCO Transmission Planning provides RFC, its Regional Reliability Organization, with dynamic and steady state modeling and simulation data as required by that entity. The NIPSCO model reflects the most likely transmission system upgrades to be in service for each case being modeled in the series. NIPSCO conforms to NERC Standards for modeling (MOD). Required data may include network changes, load profiles, voltage schedules, generation availability, and interchange schedules. Interconnection data is jointly coordinated with outside organizations related to the intertie. Current intertie circuit ratings can be viewed in Exhibit I below.

NIPSCO also participates in the Midwest ISO Transmission Planning process. Consistent with FERC Order 890, NIPSCO supplies project information to the ISO for posting. In general, projects submitted by NIPSCO to Midwest ISO MTEP Appendices A or B with a 'planned' status are modeled in Midwest ISO studies and concur with modeling representation in the concurrently developed NERC MMWG model series. These projects were identified as addressing a system need and have been tested to be the preferred solution to mitigate thermal or voltage violations than alternatives. However, because cut-off dates may differ, project status or in-service dates may differ. More information of the Midwest ISO's planning process can be found at their website.

NIPSCO

Exhibit I.

Areas Tied	Tie Location @	Voltage kV	Summer[1] Normal MVA	Summer Emergency MVA	Winter[2] Normal MVA	Winter Emergency MVA
NIPS–AEP	Dekalb-Auburn Line	138 kV	45	45	45	45
	F.G. Hiple - East Elkhart Line	345 kV	1,409	1,409	1,781	1,781
	F.G. Hiple - Collingwood Line	345 kV	1,409	1409	1,733	1,781
	Howe – Sturgis Line	69 kV	47	47	51	51
	Maple – New Carlisle Line	138 kV	136	137	180	191
	Maple – Springville Line[3]	69 kV	47	47	59	59
	Michigan City – Laporte Line	138 kV	156	156	191	191
	Northeast – Columbia Line	138 kV	136	143	143	143
	Northeast – Kline Line	138 kV	168	246	221	280
	Northport – Albion Line	138 kV	159	184	200	215
	Reynolds Sub.	345 kV	318	318	318	318
	Stillwell – Dumont Line	345 kV	1,409	1,409	1,697	1,781
	Trail Creek –New Carlisle Line	138 kV	151	151	191	191
NIPS-CE	St. John - Crete Line	345 kV	1,091	1,091	1,195	1,195
	St. John - Green Acres Line[4]	345 kV	1,091	1,091	1,310	1,310
	Green Acres - Olive Line	345 kV	971	971	1,195	1,195
	Munster – Burnham Line	345 kV	973	1,069	1,053	1,143
	Roxana–State Line Gen Line	138 kV	253	253	287	287
	Sheffield – Burnham Line	345 kV	973	1,069	1,053	1,143
	Sheffield – State Line Line	345 kV	1,195	1,195	1,195	1,195
	Wolf Lake – State Line Line	138 kV	504	509	539	539
NIPS-AMRN	Morrison Ditch – Watseka Line	138 kV	239	239	239	239
NIPS-ITC	Barton Lake –Kinderhook Line	138 kV	215	215	215	215
NIPS-DEM	Leesburg – Deedsville Line	345 kV	734	780	780	780
	Monticello – Springboro Line	138 kV	287	287	287	287
	Rochester Tap -Rochester Line	69 kV	45	45	59	59
	S. Prairie – Westwood Line	138 kV	129	129	161	161

1. Summer Ratings – May through September
2. Winter Ratings – October through April

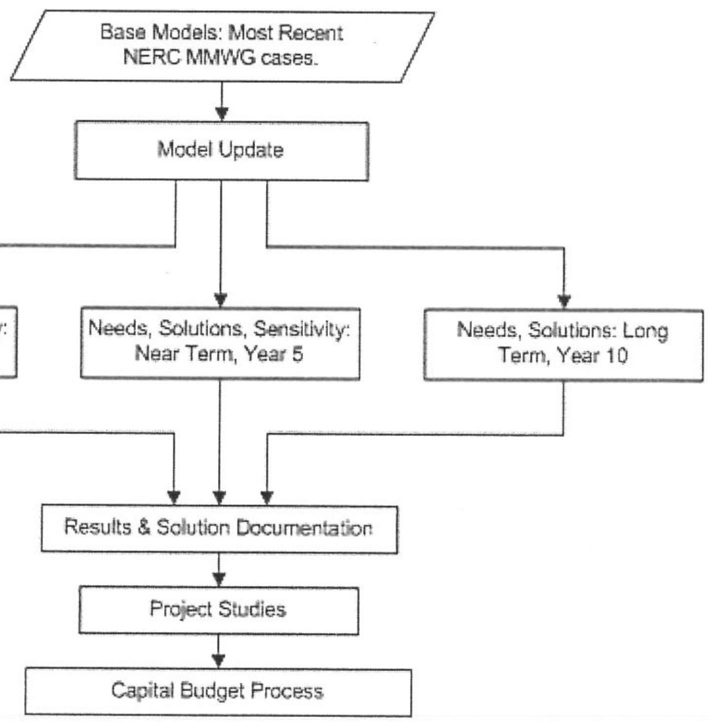
NIPSCO

Part 5. Transmission Planning Assessment Practices

5.1 Overview

This document describes the process that Transmission Planning uses to analyze the network transmission system for annual assessment. Based on planning criteria, as described in Part 4, constraints or system limitations are identified and mitigation plans are studied for the best possible solution.

NIPSCO's planning process is summarized in the figure below:



5.2 Base Models and Model Updates

Base Models used for assessment are taken from the most recent series of NERC MMWG cases. As discussed in part 4, NIPSCO is required by NERC Modeling standards, MOD-010 and MOD-012, to provide network data that reflects as accurately as possible its projected future transmission system. Loads are adjusted using NIPSCO's latest load forecast. Anticipated transmission upgrades, generation interconnections, generation availability, voltage schedules, and other updates known by the RFC cut-off dates are submitted and modeled. Study cases may be modified to reflect changes in individual project scope or in-service dates that may have changed between model submittal and study commencement.

5.3 Needs, Solutions, Sensitivities

Study Years

Assessment study years are chosen by model availability and in accord with the applicable NERC Transmission Planning standard requirements. For the near term including years 1 through 5, year 5 is chosen for study. Analysis for capital project need is focused on year 5, because ample lead time exists and load projections are more accurate than later years. The near term study results will also verify the growing need of projects proposed in previous year's assessments. For the long term spanning years 6 through 10, year 10 is chosen for study. Year 10 studies assess the effectiveness of our planned projects over time. Though the year 10 study may indicate a need for transmission enhancements, all projects identified are considered conceptual and are placed in the out years budget. Conceptual projects may require further study as the projects move closer to NIPSCO five year budget plan.

Demand Levels

The NIPSCO area is summer peaking. Therefore summer peak models are chosen for simulation studies in the years discussed above. Summer peak models are built using 50/50 load projections, meaning that there is a 50 percent chance that the load level will either fall below or exceed projection. Sensitivity studies are done on one or both of the near term cases. Scenarios vary and are chosen by the transmission planners and management based on external studies and/or operational feedback. Examples include, warmer summer with higher loading (90/10), high West- to-East market flow, or the effect of wind generation on our system.

Computer Simulations

In addition to study of system normal conditions, computer simulations of transmission outages are run against all base cases. Contingency files are written and filed by NERC category. At a minimum, NERC category B, loss of a single element, computer simulations are performed across all selected study years, demand levels, and any critical system conditions or scenarios chosen. Selected external, non-NIPSCO, facility outages are also simulated for study. Selection of these elements was based upon NIPSCO experience with the operational status of individual elements, which can have a significant impact on power flow and voltage levels on the NIPSCO transmission system. NERC category C and D, multiple element outages, are simulated on the near term summer peak cases. The Transmission Planning Engineer performing the study has the discretion to run further contingency analysis deemed appropriate. Changes in load forecast or lack thereof may indicate a need for additional study. Probability of contingency and critical system conditions chosen, along with uncertainty of future load, may also be considered. Rationale for elements not studied is documented.

In all study cases, all existing and planned control devices are simulated to the extent possible.

5.4 Study Results

Documentation
Results of computer simulations are analyzed for accuracy. Based on system performance criteria discussed in Part 4, constraints are identified or verified from previous assessments and documented. For new constraints, possible mitigation plans are discussed and documented.

Project Studies
If system enhancements are concluded to be the solution, potential projects are explored, analyzed, and sent for estimate to be included in the next 5 year budget cycle.

Capital Budget Process
All projects go through a project prioritization process. Those mandated by a NERC standard or other regulatory requirement receive top priority. Benefit-to-Cost ratios are calculated and reviewed by peer groups; preferred solution to a specific need is identified; and solution is prioritized against other capital projects. Risk assessments are done on projects that in-service dates are estimated to be beyond need date.

Table F-1
Self-Build Supply Side

	PC	Nuclear	IGCC	CCGT	CT_7FA	CT_Aero
Rated Capacity (MW)	750	1,100	624	606	204	48
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table F-2
Self-Build Renewable

	Biomass	Solar	Wind
Rated Capacity (MW)	50	50	50
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Sensitivity Charts

Figure F-1
Fuel Commodity and Transportation

[redacted]

Figure F-2
Environmental Forecast

[redacted]

Figure F-3
External Energy Market Forecast

[redacted]

Figure F-4
Load Growth Sensitivities - Peak

[redacted]

Figure F-5
Average External Energy Prices

[redacted]

Figure F-6
Natural Gas Prices

[redacted]

Figure F-7
Average External Energy Prices

[redacted]

Report on the

Generation Technology Assessment

for

NIPSCO

Project No. 60143

April 2011

Burns & McDonnell
SINCE 1898

Generation Technology Assessment

prepared for

Northern Indiana Public Service Company
Merrillville, Indiana

April 2011

Project No. 60143

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

FINAL

TABLE OF CONTENTS

Page No.

* * * * *

LIST OF TABLES

Table No. **Page No.**

* * * * *