energy data

ENERNOC

Annual Report 2012

PLUM represents the peak demand for electricity across our customer base. As of the end of 2012, the peak load for our demand response customer base, or PLUM, was between 24,000 and 27,000 megawatts. Between 30 and 35 percent of that PLUM is curtailable for demand response dispatches.

Our technology advancements have also driven our expansion into the agricultural demand response market. By introducing a new wireless mesh communications system to collect data from remote agricultural pumps, we are able to cost-effectively manage widely distributed demand response assets.

In the United States alone, farms spend more than $1.5 billion on electricity to power irrigation, representing an estimated 7 gigawatts of peak demand. Many utilities have developed irrigation-specific demand response programs, with irrigators providing significant value to the grid through the flexibility in their operations while earning important financial incentives. We are involved in a number of these programs, and recently announced a new contract with PacifiCorp, EnerNOC's largest contract to date in the irrigation load control space and a capacity-based delivery model aligned with our other utility bilateral demand response contracts for C&I capacity.

Coupling our team's passion and deep energy expertise with the power of our energy management applications puts us in a unique position to capitalize on the broader market conditions that are trending favorably in the years ahead: PJM pricing is returning to pre-2011 pricing levels, Australia continues to deliver strong top-line numbers, and utilities are deepening their relationships with us. We also anticipate growth in most demand response markets and continued growth related to our energy efficiency applications. Our balance sheet is healthy with $115 million of cash and equivalents, and we've generated positive free cash flow for three consecutive years totaling over $50 million cumulatively. We have a demand response platform that supports almost 14,000 C&I sites, the industry's leading brand and technology, a great team with seasoned leadership, ongoing investment in our technology platform, and a heightened focus on profitability.

Sincerely,

Tim Healy

Timothy G. Healy
Chairman and CEO

ENERNOC'S COMMITMENT TO SUSTAINABILITY

EnerNOC's vision to change the way the world uses energy begins with our own team. Since EnerNOC's founding, we have encouraged our employees to integrate sustainable practices into everyday life, inside and outside of work. Throughout 2012 we continued to promote – both programmatically and financially – environmental responsibility and action among all employees. We continued our company-wide program, called Practically Green, to encourage communication, focus educational efforts, and inspire sustainability actions by our employees.

On the corporate level, in 2012 we committed to developing a long-term plan to elevate our corporate sustainability participation in a more transparent way. Throughout the year an internal taskforce evaluated current activities and created a plan to engrain sustainable practices into every facet of the corporation, from procurement of goods to hiring. Our commitment is reflected in the decision to relocate in the spring of 2013 to our new, best-in-class energy efficient corporate headquarters, which is Boston's first LEED Gold new building construction project. We continue to be creative and thoughtful about the impact of our decisions to ensure a more sustainable future for our business, community, and environment.

Chairman's Letter

Dear Shareholders,

With 2012 officially in the books, I'm excited to take this opportunity to reflect on our accomplishments over the past year, but more importantly to convey my excitement about the years ahead. The past two years were not without their challenges for EnerNOC – record low pricing in some of the biggest demand response markets and a sometimes-difficult regulatory environment are two examples – but we persevered and prevailed. Even with that backdrop, EnerNOC posted win after win: we achieved significant growth in the Australia and New Zealand markets, effectively managed our PJM portfolio to deliver strong results under new market rules, successfully grew our energy efficiency business, and signed multiple new utility contracts. We also streamed billions of data points into our cloud-based energy management platform, released dozens of new features in our software – including a white-label offering for our utility customers, an enhanced automatic fault detection engine, and support for new demand response products in international markets – and delivered more than $115 million in customer savings, all while simultaneously implementing rigorous new processes across the organization to drive operational efficiency and enhance profitability.

All in all, our business has never been in a better position to succeed in its mission to change the way the world uses energy.

Underlying our success over the last year and fueling our optimistic outlook for the years ahead are the incredible advancements we have made in our cloud-based energy management platform. Although our focus on platform development and building EnerNOC into a leading provider of energy intelligence software has been largely under the radar until recently, today EnerNOC collects approximately 1.4 billion data readings per month and this platform is proving to be a real competitive differentiator. Our technology gives us unprecedented visibility into how businesses throughout the world consume (and often times, waste) energy and affords us the ability to monetize energy savings opportunities for our customers in more robust and high impact ways, such as through more discrete and targeted dispatches of demand response resources, more scalable identification of low- and no-cost energy efficiency measures, and more accurate profiling of our customers' supply procurement needs.

To better quantify just how much electricity consumption we are monitoring every day, we introduced a new operating metric this year: Peak Load Under Management, or PLUM.

2012 AT A GLANCE

$278M
Amount of revenue in 2012

$1.6B
Amount of contracted revenue as of June 1, 2012

$115M
Amount of cash & cash equivalents at the end of 2012

3
Number of consecutive years of positive free cash flow

5,900
Number of commercial, institutional, and industrial (C&I) customers

13,700
Number of C&I DemandSMART sites

24,000-27,000
Megawatts of Peak Load Under Management (PLUM)

2,100
Number of C&I EfficiencySMART sites

500+
Number of active EfficiencySMART services projects

12
Number of readings taken per year by a basic electricity meter

35,000
Number of readings taken by a typical meter in EnerNOC's network

5
Number of countries where EnerNOC has commercial operations

1
EnerNOC

*All numbers as of 12/31/12 unless otherwise noted.

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Boston, Massachusetts 02110
Phone: 617.224.9900
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59 Maiden Lane
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Phone: 800.937.5449

Legal Counsel
Mintz, Levin, Cohn, Ferris, Glovsky and Popeo, P.C.
One Financial Center
Boston, Massachusetts 02111
Phone: 617.542.6000

Common Stock Information
Our common stock is listed on The Nasdaq Global Market under the symbol "ENOC".

Independent Registered Public Accounting Firm
Ernst & Young
200 Clarendon Street
Boston, Massachusetts 02116

Board Members
Timothy G. Healy
Chairman of the Board and Chief Executive Officer

David B. Brewster
President and Director

Richard Dieter
Director, Audit Committee Chair

T.J. Glauthier
Director, Compensation Committee Chair

Arthur Coviello
Lead Independent Director

Susan F. Tierney
Director, Nominating and Governance Committee Chair

James Baum
Director

Executive Team
Timothy G. Healy
Chairman of the Board and Chief Executive Officer

David B. Brewster
President and Director

Neal Moses
Chief Financial Officer

David M. Samuels
Executive Vice President

Gregg M. Dixon
Senior Vice President of Marketing and Sales

Kevin J. Bligh
Chief Accounting Officer

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2012

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 001-33471

EnerNOC, Inc.

(Exact Name of Registrant as Specified in its Charter)

Delaware *(State or Other Jurisdiction of Incorporation or Organization)*	**87-0698303** *(IRS Employer Identification No.)*
101 Federal Street **Suite 1100** **Boston, Massachusetts** *(Address of Principal Executive Offices)*	**02110** *(Zip Code)*

Registrant's telephone number, including area code:
(617) 224-9900

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.001 par value	The NASDAQ Stock Market LLC (The NASDAQ Global Market)

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one).

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the Registrant's common stock held by non-affiliates of the Registrant as of June 29, 2012, the last business day of the Registrant's second quarter of the fiscal year ended December 31, 2012, was approximately $149.7 million based upon the last sale price reported for such date on The NASDAQ Global Market.

The number of shares of the Registrant's common stock (the Registrant's only outstanding class of stock) outstanding as of February 25, 2013 was 29,996,331.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for its 2013 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A not later than 120 days after the end of the Registrant's fiscal year ended December 31, 2012, relating to certain information required in Part III of this Annual Report on Form 10-K are incorporated by reference into this Annual Report on Form 10-K.

EnerNOC, Inc.

ANNUAL REPORT ON FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2012

Table of Contents

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. For this purpose, any statements contained herein regarding our strategy, future operations, financial condition, future revenues, profits and profit margins, projected costs, market position, prospects, plans and objectives of management, other than statements of historical facts, are forward-looking statements. The words "anticipates," "believes," "estimates," "expects," "intends," "may," "plans," "projects," "will," "would" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. We cannot guarantee that we actually will achieve the plans, intentions or expectations expressed or implied in our forward-looking statements. Matters subject to forward-looking statements involve known and unknown risks and uncertainties, including economic, regulatory, competitive and other factors, which may cause actual results, levels of activity, performance or the timing of events to be materially different than those exposed or implied by forward-looking statements. Important factors that could cause or contribute to such differences include the factors set forth under the caption "Risk Factors" in Item 1A of Part I of this Annual Report on Form 10-K. Although we may elect to update forward-looking statements in the future, we specifically disclaim any obligation to do so, even if our estimates change, and readers should not rely on those forward-looking statements as representing our views as of any date subsequent to February 27, 2013.

Our trademarks include: EnerNOC, ENERBLOG, Get More from Energy, PowerTrak, PowerTalk, DemandSMART, EfficiencySMART, SiteSMART, SupplySMART, One-Click Curtailment, Clean Green California, CarbonTrak and The Greenest Kilowatt-Hour is the One Never Used.

Other trademarks or service marks appearing in this Annual Report on Form 10-K are the property of their respective holders.

PART I

Item 1. Business

We use the terms "EnerNOC," the "Company," "we," "us" and "our" in this Annual Report on Form 10-K to refer to the business of EnerNOC, Inc. and its subsidiaries.

Company Overview

We are a leading provider of energy management applications, services and products for the smart grid, which include comprehensive demand response, data-driven energy efficiency, and energy price and risk management applications, services and products. Our energy management applications, services and products enable cost effective energy management strategies for commercial, institutional and industrial end-users of energy, which we refer to as our C&I customers, and our electric power grid operator and utility customers by reducing real-time demand for electricity, increasing energy efficiency and improving energy supply transparency.

We believe that we are the world's leading provider of demand response applications and services. Demand response is an alternative to traditional power generation and transmission infrastructure projects that enables electric power grid operators and utilities to reduce the likelihood of service disruptions, such as brownouts and blackouts, during periods of peak electricity demand, and otherwise manage the electric power grid during short-term imbalances of supply and demand or during periods when energy prices are high.

In providing our demand response services, we match obligation, in the form of megawatts, or MW, that we agree to deliver to our utility and electric power grid operator customers, with supply, in the form of MW that we are able to curtail from the electric power grid through our arrangements with C&I customers. We increase our ability to curtail demand from the electric power grid by deploying a sales team to contract with our C&I customers and by installing our equipment at these customers' sites to connect them to our network. When we are called upon by our utility or electric power grid operator customers to deliver MW, we use our Network Operations Center, or NOC, and our comprehensive demand response application, DemandSMART, to remotely manage and reduce electricity consumption across a growing network of C&I customer sites, making demand response capacity available to electric power grid operators and utilities on demand while helping C&I customers achieve energy savings, improved financial results and environmental benefits. We receive recurring payments from electric power grid operators and utilities for managing demand response capacity and we share these recurring payments with our C&I customers in exchange for those C&I customers reducing their power consumption when called upon. We occasionally reallocate and realign our capacity supply and obligation through open market bidding programs, supplemental demand response programs, auctions or other similar capacity arrangements and bilateral contracts to account for changes in supply and demand forecasts, as well as changes in programs and market rules in order to achieve more favorable pricing opportunities. We refer to the above activities as managing our portfolio of demand response capacity.

We build on our position as a leading demand response services provider by using our NOC and energy management application platform to deliver a portfolio of additional energy management applications, services and products to new and existing C&I, electric power grid operator and utility customers. These additional energy management applications, services and products include our EnerNOC EfficiencySMART and SupplySMART applications and services, and certain wireless energy management products. EfficiencySMART is our data-driven energy efficiency suite that includes energy efficiency planning, audits, assessments, commissioning and retro-commissioning authority services, and a cloud-based energy analytics application used for managing energy across a C&I customer's portfolio of sites. The cloud-based energy analytics application also includes the ability to integrate with a C&I customer's existing energy management system, provide utility bill management and tools for measurement, tracking, analysis, reporting and management of greenhouse gas emissions. SupplySMART is our energy price and risk management application that provides our C&I customers located in restructured or deregulated markets throughout the United States with the ability to more effectively manage the energy supplier selection process, including energy supply product procurement and implementation, budget forecasting, and utility bill management. Our wireless energy management products are designed to ensure that our C&I customers can connect their equipment remotely and access meter data securely, and include both cellular modems and an agricultural specific wireless technology solution acquired as part of our acquisition of M2M Communications Corporation, or M2M, in January 2011.

Since inception, our business has grown substantially. We began by providing demand response services in one state in 2003 and have expanded to providing our portfolio of energy management applications, services and products in several regions throughout the United States, as well as internationally in Australia, Canada, New Zealand and the United Kingdom.

Strategy

Our strategy is to capitalize on our established track record, substantial operating experience and scalable and proprietary energy management platform, as well as our leading market position in the United States, to continue providing energy management applications, services and products to our C&I, electric power grid operator and utility customers. Our goal is to become the leading outsourced energy management service provider for C&I, electric power grid and utility customers worldwide. Key elements of our strategy include:

Strengthen Demand Response Presence by Growing in Existing and New Regions in the United States. We will continue to actively pursue opportunities to provide demand response services to electric power grid operators and utilities in markets in the United States through additional long-term contracts and open market program opportunities for demand response resources. To provide these demand response resources, we intend to enter into contracts with new C&I customers. We believe that our DemandSMART application and services, the recurring payments that we provide to C&I customers and our national presence will enable us to continue to pursue rapid growth of our C&I customer base and strengthen our presence as a leader in providing demand response services.

Expand Sales of our Portfolio of Additional Energy Management Applications, Services and Products. We intend to continue to leverage our leadership role in the demand response market to deliver a portfolio of additional energy management applications, services and products to new and existing C&I customers, including our EfficiencySMART and SupplySMART applications and services, and certain wireless energy management products. We will continue to develop our technology, including our proprietary energy management application platform, which enables us to measure, manage, benchmark and optimize C&I customers' energy consumption and facility operations, and connect to electric power grid operator and utility control rooms. We believe that our C&I customers will become increasingly aware of their energy costs and consumption and will look to advanced analytics and trusted third-party providers to help them better manage their overall energy expenditures. Therefore, we will continue to leverage the detailed energy data that we collect at our C&I customer sites to provide our EfficiencySMART application and services to help our C&I customers drive down operating costs associated with energy expenses and help our electric power grid operator and utility customers meet their energy efficiency targets. We will also continue to aggressively promote our SupplySMART application and services to our C&I customers to enable them to mitigate risk through competitive energy supply contracts and achieve energy cost savings.

In addition, in connection with our acquisition of M2M in January 2011, we expanded our technology platform to include certain agricultural specific wireless energy management products. We believe that these wireless energy management products will provide a significant opportunity to grow our C&I customer base in the agricultural market for demand response.

Target Expansion by Entering International Markets. We also intend to expand our addressable market by pursuing demand response and energy management opportunities in international markets. We are a leader in the development, implementation and broader adoption of energy management applications, services and products for the smart grid and have built a national footprint in the United States. We believe we can achieve a similar significant first-mover advantage internationally, principally in Australia, Canada, New Zealand and the United Kingdom. We believe that our scalable technology platform and proprietary operational processes are readily adaptable to the international markets that we are targeting. We also believe that entering new international markets, including Asia and Europe, will provide a significant opportunity to grow our C&I customer base and provide a differentiated offering to C&I customers with international operations.

Actively Pursue Targeted Strategic Acquisitions. We intend to actively pursue selective acquisitions to reinforce our leadership position in the expanding energy management applications, services and products sector. This sector consists of a number of companies with technology offerings or customer relationships that present attractive acquisition opportunities. We intend to look for opportunities to acquire technologies that would support and enhance our current energy management application platform. Customer relationship acquisitions will focus on expansion into new geographic regions both in the United States and internationally. We have a strong track record of successfully integrating acquired companies to increase our customer base, entering new geographic regions, improving our offerings and enhancing our technology.

Energy Management Applications, Services and Products

DemandSMART

Demand response is achieved when C&I customers reduce their consumption of electricity from the electric power grid in response to a market signal, such as capacity constraints, price signals or transmission-level imbalances. C&I customers can reduce their consumption of electricity by reducing demand (for example, by dimming lights, resetting air conditioning set-points or shutting down production lines) or they can self-generate electricity with onsite generation (for example, by means of a back-up generator or onsite cogeneration). Our demand response capacity provides a more timely, cost-effective and environmentally-sound alternative to building conventional supply-side resources, such as natural gas-fired peaking power plants, to meet periods of peak electricity demand.

We are a leader in the development, implementation and broader adoption of technology-enabled demand response services for the smart grid. Our DemandSMART application enables us to send control signals to, and receive bi-directional communications from, an Internet-enabled network of broadly dispersed C&I customer sites in order to initiate, monitor and complete demand response activity. Our robust and scalable technology and proprietary operational processes have the ability to automate demand response and simplify C&I customer participation by remotely reducing electricity usage in a matter of minutes, or send curtailment instructions to our C&I customers to be manually implemented on site. The devices that we install at our C&I customer sites transmit to us via the cellular network and Internet near real-time electrical consumption data on a 1-minute, 5-minute, 15-minute or hourly basis. Our DemandSMART application analyzes the data from individual sites and aggregates data for specific regions. When a demand response event occurs, our NOC automatically processes the notification coming from the electric power grid operator or utility. Our NOC operators then begin activating procedures to curtail demand from the grid at our C&I customer sites. Our one-click curtailment activation sends signals to all C&I customer sites in the targeted geography where the event is occurring. Upon activation of demand reduction, DemandSMART, which receives near real-time data from each C&I customer site, is able to determine on a near real-time basis whether the location is performing as expected. Signals are relayed to our NOC operators when further steps are needed to achieve demand reductions at any given location. Each C&I customer site is monitored for the duration of the demand response event and operations are restored to normal when the event ends. DemandSMART is designed for the C&I customer market, which represents approximately 60% of the United States electricity consumption.

We provide our demand response services to electric power grid operators and utilities under long-term contracts and pursuant to open market bidding programs. Our long-term contracts generally have terms of three to ten years and predetermined capacity commitment and payment levels. Our open market bidding program opportunities are generally characterized by flexible capacity commitments and prices that vary by hour, day, month, or bidding period. Within these contracts and open market programs, we offer the following services to address the needs of electric power grid operators and utilities: (i) reliability-based demand response, (ii) price-based demand response, and (iii) short-term reserve resources referred to in the electric power industry as ancillary services.

Reliability-Based Demand Response. We receive recurring capacity payments, which we share with our C&I customers, from electric power grid operators and utilities for being on call, which means having available previously registered demand response capacity that we have aggregated from our C&I customers, regardless of whether we receive a signal to reduce consumption. When we receive a signal from an electric power grid operator or utility customer, which we refer to as a dispatch signal, our DemandSMART application automatically notifies our C&I customers that a demand reduction is needed and initiates processes that reduce electrical consumption by our C&I customers in the targeted area. When we are called to implement a demand reduction, we typically receive an additional payment, which we share with our C&I customers, for the energy that we reduce. We refer to this as an energy payment. We are called upon to perform by electric power grid operators and utilities during periods of high demand or supply shortfalls, otherwise known as capacity deficiency events. By aggregating a large number of C&I customers to participate in these reliability-based programs, we believe that we have played a significant role over the past several years in helping to prevent brownouts and blackouts in some of the most capacity constrained regions in the United States. We currently provide reliability-based demand response services to ISO New England, Inc., or ISO-NE, PJM Interconnection, or PJM, Southern California Edison Company, Tennessee Valley Authority, Australian Independent Market Operator Wholesale Electricity Market and Ontario Power Authority, or OPA, among others.

Price-Based Demand Response. Our price-based demand response services enable C&I customers to monitor and respond to wholesale electricity market price signals when it is cost-effective for them to do so. Our C&I customers use our DemandSMART application to register a "strike price" above which it may be economical for that customer to reduce its consumption of electricity. We receive an energy payment in the amount of the wholesale market price for the electricity that the C&I customer does not consume and share this payment with the C&I customer. If prices in a given market approach a given strike price, DemandSMART automatically notifies the C&I customer and initiates processes that reduce electrical consumption from the electric power grid. We currently participate in price-based demand response programs in the Mid-Atlantic and New England.

Ancillary Services. Demand response is utilized for short-term reserve requirements, referred to in the electric power industry as ancillary services, including operating reserves. This service is called upon by electric power grid operators and utilities during short-term contingency events such as the loss of a transmission line or large power plant. Through our technology, certain C&I customers are able to provide near instantaneous response for these short-term system dispatches, and often do so with negligible impact on their business operations. Electric power grid operators and utilities rely on a reserve pool of these quick-start resources to provide short-term support as needed during these contingency events. The goal of electric power grid operators and utilities is to get these resources back into standby mode as quickly as possible after they are dispatched so that the reserve pool of available capacity is replenished. An example of an ancillary services market in which we participate is PJM's Synchronized Reserves Market, in which we were the first provider of demand response capacity.

We may choose to participate in additional or different markets in the future based upon various factors, including without limitation our ability to negotiate acceptable pricing arrangements in such markets.

EfficiencySMART

EfficiencySMART is our data-driven energy efficiency suite that includes energy efficiency planning, audits, assessments, commissioning and retro-commissioning authority services, and a cloud-based energy analytics application used for managing energy across a C&I customer's portfolio of sites. The cloud-based energy analytics application also includes the ability to integrate with a C&I customer's existing energy management system, provide utility bill management and tools for measurement, tracking, analysis, reporting and management of greenhouse gas emissions. We currently offer the following EfficiencySMART applications and services:

- **EfficiencySMART Plan** provides our C&I customers with a multi-year profile of projected energy demand, consumption and costs, including a lifecycle financial analysis of potential energy strategies and a roadmap for implementation.

- **EfficiencySMART Audit** provides our C&I customers with energy efficiency recommendations in compliance with the American Society of Heating, Refrigeration and Air-Conditioning, or ASHRAE, standards for conditioned space, and tactical energy surveys for industrial facilities.
- **EfficiencySMART Assessment** provides detailed recommendations for energy savings, demand reductions, reductions in energy intensity through operation and maintenance activities, equipment retrofits, behavioral changes, or the use of new technologies. Sample Assessments include compressed air audits, chiller sequence optimization, hot water leak detection, hydraulic studies, or central plant assessments.
- **EfficiencySMART Commissioning** includes traditional and/or new building commissioning services, such as investigation, testing and verification of energy efficiency strategies, and data analytics over a specified period of time.
- **EfficiencySMART Insight** provides our large, multi-site C&I customers with a Software-as-a-Service enterprise energy management solution that provides persistent commissioning with the ability to visualize near real-time energy usage, identify savings opportunities, and prioritize energy-related investments across a portfolio of meters and buildings across a C&I customer's organization. EfficiencySMART Insight provides C&I customers with the ability to remotely host and monitor large portfolios of meters, compute and compare baseline and benchmark data, identify the best and worst performing sites across a variety of energy usage and operational metrics, configure the rate engine for shadow billing analysis, set alerts on energy-related data streams and monitor demand levels. In addition, the functionality of the EfficiencySMART Insight solution can be expanded to directly integrate with a C&I customer's existing energy management system, provide utility bill management and tools for measurement, tracking, analysis, reporting and management of greenhouse gas emissions.

We have an expanding portfolio of EfficiencySMART applications and services. We provide our EfficiencySMART applications and services both directly to the C&I customer market and to utility customers under long-term contracts as a mechanism for the utilities to meet either mandated or voluntary energy efficiency targets in their service territory. Our EfficiencySMART applications and services are aimed at helping address increasingly complex energy challenges. We believe that the market opportunities for our EfficiencySMART applications and services are significant and will remain so as operational efficiency and energy savings are given increased priority by electric power grid operators, utilities and C&I customers.

We recently made the strategic decision to integrate CarbonSMART, our enterprise carbon management application, into our EfficiencySMART Insight solution, thereby eliminating CarbonSMART as a stand alone solution. We did this because our EfficiencySMART Insight solution already has rich greenhouse gas calculation dashboards and scorecards and, more importantly, provides thorough mitigation strategies in the form of detailed energy efficiency measures.

SupplySMART

SupplySMART is our energy price and risk management application that provides our C&I customers located in restructured or deregulated markets throughout the United States with the ability to more effectively manage the energy supplier selection process, including energy supply product procurement and implementation. SupplySMART provides a framework for developing and implementing risk management strategies and executing purchasing strategies that provide maximum price transparency and structural savings on an ongoing basis for our C&I customers. Using a competitive bid process, SupplySMART delivers recommendations on energy price structures, terms and conditions from available competitive suppliers of energy commodities, including electricity, natural gas and refined products. SupplySMART includes a set of online features including centralizing, tracking, and presenting utility bill and enterprise-wide utility financial information, such as budgets and forecasts, while assessing bill accuracy and savings opportunities. SupplySMART also includes an online procurement tool that bids commodity purchases amongst competitive suppliers.

Other Products

We provide wireless products for energy management and demand response that are designed to ensure that our C&I customers can connect their equipment remotely and access meter data securely. These products include cellular modems and an agricultural specific wireless technology solution acquired as part of our acquisition of M2M in January 2011.

Technology and Operations

Since inception, we have focused on delivering industry-leading, technology-enabled energy management applications, services and products. Our proprietary technology has been developed to be highly reliable and scalable, and to provide a platform on which to design, customize, and implement our energy management applications, services and products. Our proprietary technology infrastructure is built on Linux, Java and Oracle, and supports an open web services architecture. Our enterprise energy management application platform enables us to efficiently scale our DemandSMART, EfficiencySMART, and SupplySMART applications and services, as well as certain wireless energy management products, in new geographic regions and rapidly grow the number of C&I customers in our network. Our energy management application platform leverages web services and wireless technologies that connect applications directly with other applications through a form of "loose coupling," which allows connections to be established across applications without customization. As a result, these connections can be established across firewalls without regard to technology platform or programming language, making it easy to apply our technology across a broad range of C&I customers.

Our technology can be broken down into three primary components: the NOC, our energy management application platform and the EnerNOC Site Server.

Network Operations Center

Our technology enables our NOC to automatically respond to signals sent by electric power grid operators and utilities to deliver demand reductions within targeted geographic regions. We can customize our technology to receive and interpret many types of dispatch signals sent directly from an electric power grid operator or utility customer to our NOC. Following the receipt of such a signal, our NOC automatically notifies specified C&I customer personnel of the demand response event. After relaying this notification to our C&I customers, we initiate processes that reduce their electricity consumption from the electric power grid. These processes may include dimming lights, shifting equipment to power save mode, adjusting heating and cooling set points and activating a back-up generator. Demand reduction is monitored remotely with near real-time data feeds, the results of which are displayed in our NOC through various data presentment screens. Each C&I customer site is monitored for the duration of the demand response event and operations are restored to normal when the event ends. We currently participate in demand response programs across the United States, Australia, Canada, New Zealand and the United Kingdom.

Energy Management Platform

Our energy management platform is comprised of our cloud-based enterprise software platform used for DemandSMART, EfficiencySMART and SupplySMART, as well as wireless energy management products and technology, and is the underlying system that runs our NOC. It utilizes a modular web services architecture that is designed to allow application modules to be easily integrated into the platform. We believe that a key factor to successfully offering energy management applications, services and products is integrating data from disparate sources and utilizing it to deliver customer-focused services utilizing open protocols.

Currently, our energy management application platform collects approximately 1.5 billion monthly readings of facility energy consumption data on a 1-minute, 5-minute, 15-minute or hourly basis and integrates that data with near real-time, historical and forecasted market variables. We use our energy management platform to measure, manage, benchmark and optimize C&I customers' energy consumption and facility operations. We use this data to help C&I customers analyze consumption patterns, forecast demand, measure real-time performance during demand response events, continuously monitor building management equipment to optimize system operation, model rates and tariffs and create energy scorecards to benchmark similar facilities. In addition, our energy management application platform has the ability to track our C&I customers' greenhouse gas emissions by mapping their energy consumption with the fuel mix used for generation in their location, such as the proportion of coal, nuclear, natural gas, fuel oil and other sources used.

We have also deployed at certain of our DemandSMART C&I customer sites the industry's first presence-enabled smart grid technology, which enables real-time communication through open, standards-based presence technology between most Internet-enabled smart meters or devices and our NOC. The always-on, two-way presence-based connection significantly enhances visibility into our demand response network and also streamlines the C&I customer site enablement process, allowing us to more efficiently equip C&I customers to participate in demand response programs. These devices are "firewall friendly" and can leverage existing C&I customer networks to facilitate secure, authenticated and encrypted communication, without the need to establish a virtual private network.

In 2011, we extended the capability of our energy management application platform to support a certain demand response program in Canada by providing automatic and remote reductions of electricity from the electric power grid in 0.2 seconds or less. We believe that this new key capability differentiates us from our competitors and enhances our leadership position in the demand response industry.

The EnerNOC Site Server

We design and install a small device, called an EnerNOC Site Server, or ESS, at each C&I customer site to collect and communicate to our platform near real-time electricity consumption data and, in certain cases, enable remote control of a C&I customer's electricity consumption. The ESS communicates to our NOC through the C&I customer's LAN or secure internet connection. The ESS is an open, integrated system consisting of a central hardware device residing inside a standard electrical box. The ESS allows our C&I customers to, among other things, respond quickly and completely to instructions from us to reduce electricity consumption. We also support OpenADR protocol on our most recent ESS devices, an emerging standard for automated demand response communications.

Sales and Marketing

As of December 31, 2012, our sales and marketing team consisted of 212 employees. We organize our sales efforts by customer type. Our utility sales group sells to electric power grid operators and utilities, while our commercial and industrial sales group sells to C&I customers. Our utility sales group is responsible for securing long-term contracts from electric power grid operators and utilities for our DemandSMART and EfficiencySMART applications, services and products. We actively pursue long-term contracts in both restructured markets and in traditionally regulated markets. Our commercial and industrial sales group sells our energy management applications, services and products to C&I customers and is located in major electricity regions throughout North America, including New England, New York, the Mid-Atlantic, Texas, Florida, California, Idaho, and internationally in Australia, Canada, New Zealand and the United Kingdom.

Our marketing group is responsible for influencing all market stakeholders including customers, energy users and policymakers, attracting prospects to our business, enabling the sales engagement process with messaging, training and sales tools, and sustaining and expanding relationships with existing C&I customers through renewal and retention programs and by identifying cross-selling opportunities. This group researches our current and future markets and leads our strategies for growth, competitiveness, profitability and increased market share.

Research and Development

As of December 31, 2012, our research and development team consisted of 90 employees. Our research and development team is responsible for developing and enhancing our existing energy management applications, services and products, as well as the engineering and design of new energy management applications, services and products. Our research and development expenses were approximately $16.2 million, $14.3 million and $10.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. During the years ended December 31, 2012, 2011 and 2010, we capitalized internal software development costs of $4.7 million, $3.2

million and $6.8 million, respectively, and these amounts are included as software in property and equipment at December 31, 2012. Included in capitalized software development costs for the year ended December 31, 2012 is $0.7 million of software development costs related to the implementation of a company-wide human resource system, which was put into production in June 2012 and is being amortized over a three-year useful life. Included in the amounts above, we also capitalized $1.3 million during the year ended December 31, 2010 related to a company-wide enterprise resource planning systems implementation project, which was placed into production in June 2011 and is being amortized over a five-year useful life.

Customers

C&I Customers

Our energy management applications, services and products provide cost effective energy management strategies for our C&I customers by reducing real-time demand for electricity, increasing energy efficiency, improving energy supply transparency, and mitigating emissions. One of our goals is to become the leading outsourced energy management service provider for C&I customers worldwide. Our commercial and industrial sales group primarily focuses their efforts on the following seven vertical markets: technology, education, food sales and storage, government, healthcare, manufacturing/industrial and commercial real estate. The following table lists some of our C&I customers as of December 31, 2012 in each of the seven key vertical markets that our commercial and industrial sales group primarily targets for DemandSMART, EfficiencySMART, SupplySMART and wireless energy management products:

Technology	Education	Food Sales and Storage	Commercial Real Estate
AT&T	Carnegie Mellon University	SuperVALU	Sears
Level 3 Communications	The California State University	Stop & Shop	Morgan Stanley
General Electric	Colorado State University	Shop Rite	Beacon Properties
Genentech	Tennessee State University	Whole Foods Markets	Morguard Investments Limited
	Western Connecticut State University		Washington Realty Investment Trust
	Memphis City Schools		

Government	Healthcare	Manufacturing/Industrial
Commonwealth of Massachusetts	Adventist Hospital	Pfizer
State of Vermont	Salford Royal	Kimberly-Clark, Inc.
State of Connecticut	NHS Foundation Trust	Southeastern Container
City of Boston, MA	Hartford Hospital	
State of Rhode Island	Genesis Healthcare	

Our contracts with C&I customers typically take two to four months to complete and have terms that generally range between one and five years.

Grid Operator and Utility Customers

We have significantly grown our base of electric power grid operator and utility customers since inception. As of December 31, 2012, we provided our DemandSMART and EfficiencySMART applications and services to electric power grid operator and utility customers in several regions throughout the United States, as well as internationally in Australia, Canada, New Zealand and the United Kingdom. Our electric power grid operator and utility customers include ISO-NE, PJM, Southern California Edison Company, Tennessee Valley Authority, Australian Independent Market Operator Wholesale Electricity Market, and OPA, among others. We may choose to participate in additional or different markets in the future based upon various factors, including without limitation our ability to negotiate acceptable pricing arrangements in such markets.

Our contracts with electric power grid operator and utility customers typically take twelve to eighteen months to complete and, when successful, typically result in multi-million dollar contracts with terms that generally range between three and ten years. We refer to these contracts as utility contracts. To date, we have received substantially all of our revenues from our electric power grid operator and utility customers for providing our energy management applications, services and products.

Competition

We face competition from other providers of energy management service applications, services and products, advanced metering infrastructure service providers, and utilities and competitive electricity suppliers who offer their own energy management applications, services and products. We also compete with traditional supply-side resources, such as peaking power plants.

The industry in which we participate is fragmented. When competing for electric power grid operator and utility customers, we believe that the primary factors on which we compete are:

- the pricing of the demand response or energy efficiency services being offered; and
- the financial stability, historical performance levels and overall experience of the energy management service provider.

When competing for C&I customers, we believe that the primary factors on which we compete are:

- the level of demand response capacity payments shared with those C&I customers for their demand response capacity;
- the level of sophistication employed by the energy management service provider to identify and optimize energy management capabilities and opportunities; and
- the ability of the energy management service provider to service multiple sites across different geographic regions and to provide additional technology-enabled energy management applications, services and products.

Our primary competitors include energy management service providers Comverge, Inc., Exelon Corporation, Energy Curtailment Specialists and Hess, Inc., as well as energy technology providers Lucid Design Group, Inc., Building IQ, SCIEnergy, Inc. and McKinstry Co., LLC. We believe that our operational experience and leadership in the energy management applications, services and products sector gives us an advantage when competing for C&I, electric power grid operator and utility customers. In addition, across our energy management application platform, we believe that we are unique in our ability to leverage real-time data across applications to unlock the greatest amount of value and efficiency for our C&I customers, which we believe positions us favorably to win in competitive situations.

With respect to our competitors, some providers of advanced metering infrastructure services have added, or may add, energy management applications, services and products like ours to their existing business. In addition, some advanced metering infrastructure service providers are substantially larger and better capitalized than we are and have the ability to combine demand response and additional energy management applications, services and products into an integrated offering to a large existing customer base.

Utilities and competitive electricity suppliers could and sometimes do also offer their own demand response services, which could decrease our base of potential C&I customers and could decrease our revenues. However, demand response programs, as administered by utilities alone, are bound to standard tariffs to which all C&I customers in the utility's service territory must abide. Utilities must treat all rate class customers equally in order to serve them under public utility commission-approved tariffs. In contrast, we have the flexibility to offer customized energy management applications, services and products to different C&I customers. We believe that we also have technology and operational experience at the facility-level that both utilities and competitive electricity suppliers lack. We believe our technological advances differentiate us from our competitors and enhance our leadership position in the demand response industry. Furthermore, we believe that our energy management applications, services and products are complementary to utilities and competitive electricity suppliers' demand response efforts because we can help enlist C&I customers to their existing programs, reduce their workload by serving as a single point of contact for an aggregated pool of C&I customers who choose to participate in their programs, and act to uphold or enhance C&I customer satisfaction. However, utilities and competitive electricity suppliers may offer energy management applications, services and products at prices below cost or even for free in order to improve their customer relations or competitive positions, which would decrease our base of potential C&I customers and could decrease our revenues. For instance, utilities and competitive electricity suppliers are increasingly providing expertise to C&I customers relating to energy audits, demand reduction or energy efficiency measures.

We also compete with traditional supply-side resources such as natural gas-fired peaking plants. In some cases, utilities have an incentive to invest in these fixed assets rather than develop demand response as they are able to include the cost of fixed assets in their rate base and in turn receive a return on investment. In addition, some utilities have a financial disincentive to invest in demand response and even more so in energy efficiency because reducing demand can have the effect of reducing their sales of electricity. However, we believe that our energy management applications, services and products will continue to gain regulatory support as they are faster to market, require no electric power generation, transmission or distribution infrastructure, and are more cost-effective and more environmentally sound than traditional alternatives.

Regulatory

We provide our energy management applications, services and products in restructured electricity markets and in traditionally regulated electricity markets. Regulations within both types of markets impact how quickly customers may adopt our energy management applications, services and products, the prices we can charge and profit margins we can earn, the MW we can enroll in certain programs, the timing with respect to when we begin earning revenue, and the various ways in which we are permitted or may choose to do business and accordingly, impact our assessments of which potential markets to most aggressively pursue. In addition, certain of our contracts with utilities are subject to regulatory approval, which regulatory approval may not be obtained on a timely basis, if at all.

The prices we can charge and revenues and profit margins we earn also can be affected by market regulations, such as program rules that discount the value of demand response resources because they can only be available during a limited number of peak demand hours. This contrasts with other types of capacity resources that may be available 24 hours per day, every day of the week. Similarly, market rules and regulations defining what constitutes demand response can affect the amount of demand response capacity that we are able to enroll from our C&I customers and the amounts that we need to pay them for their participation. For example, recent market rule changes in the PJM region restrict our ability to receive capacity market compensation for load reductions from a baseline level above a C&I customer's prior year peak load, as compared to prior rules allowing compensation for a full load drop. Regulations applicable to the energy management applications, services and products that we provide and the programs in which we participate also may change at any time and significantly impact the way that we conduct our business and our results of operations and financial condition. For example, in the event that market rules and regulations are changed subsequent to our assuming a long-term obligation, such as winning a bid to provide demand response capacity in a forward capacity market, but prior to the year in which that capacity is required to be delivered, our results of operations and financial condition could be significantly and negatively impacted. On an ongoing basis, we assess known, anticipated and potential changes to market rules and projected market prices for the energy management applications, services and products that we offer. As a result of such assessment, we may alter our participation in both potential new markets and in markets in which we currently offer our energy management applications, services and products, including by determining not to participate in open market bids to provide demand response capacity.

The policies regarding the measurement and verification of demand response resources, safety regulations and air quality or emissions regulations often vary by jurisdiction and may affect how we do business. For example, some environmental agencies may limit the amount of emissions allowed from back-up generators utilized by C&I customers, even when back-up generators are strictly used to maintain system reliability. As a result, we would have to find alternative sources of capacity to meet our capacity obligations to our electric power grid operator and utility customers.

The regulatory structures in regional electricity markets are varied and some regulatory requirements make it more difficult for us to provide some or all of our energy management applications, services and products in those regions. The regional electricity markets are generally not subject to direct price/rate regulation, but they remain heavily regulated in other ways that can impact our costs, the level compensation available, and/or the ability for demand response to participate and the terms of such participation. For instance, some markets have regulatory structures that do not yet include demand response as a qualifying resource for purposes of short-term reserve requirements known as ancillary services. As part of our business strategy, we intend to expand into additional regional electricity markets. However, unfavorable regulatory structures could limit the number of regional electricity markets available to us for expansion.

Intellectual Property

We utilize a combination of intellectual property safeguards, including patents, copyrights, trademarks and trade secrets, as well as employee and third-party confidentiality and proprietary information agreements, to protect our intellectual property. As of December 31, 2012, we held two patents in the United States, one of which expires in 2022 and the other of which expires in 2024, and one published patent application pending. We also had one issued patent in Australia, three pending or published patent applications filed under the Patent Cooperation Treaty for Canada and one published patent application pending for Australia. Our patent applications, and any future patent applications might not result in a patent being issued with the scope of the claims we seek, or at all; and any patents we may receive may be challenged, invalidated or declared unenforceable. We continually assess appropriate circumstances for seeking patent protection for those aspects of our technology, designs and methodologies and processes that we believe provide significant competitive advantages.

As of December 31, 2012, we held numerous trademarks in the United States. Several of these trademarks are also registered in the European Community, Canada, Japan, China, Australia, New Zealand and South Africa. In addition, we have a number of trademark applications pending in Japan.

With respect to, among other things, proprietary know-how that is not patentable and processes for which patent protection may not offer the best legal and business protection, we rely on trade secret protection and employ confidentiality and proprietary information agreements to safeguard our interests. Many elements of our energy management applications, services and products involve proprietary know-how, technology or data that are not covered by patents or patent applications, including technical processes, equipment designs, algorithms and procedures. We have taken security measures to protect these elements. All of our employees have entered into confidentiality and proprietary information agreements with us. These agreements address intellectual property protection issues and require our employees to assign to us all of the inventions, designs, and technologies they develop during the course of employment with us. We also generally seek confidentiality and proprietary information protection from our customers and business partners before we disclose any sensitive aspects of our technology or business strategies. We have not been subject to any material intellectual property claims.

Seasonality

Peak demand for electricity and other capacity constraints tend to be seasonal. Peak demand tends to be most extreme in warmer months, which may lead some demand response capacity markets to yield higher prices for capacity or contract for the availability of a greater amount of capacity during these warmer months. As a result, our revenues can fluctuate from quarter to quarter based upon the seasonality of our demand response business in certain of the markets in which we operate, where payments under certain of our long-term contracts and pursuant to certain open market bidding programs in which we participate are higher or concentrated in particular seasons and months. For example, in the PJM forward capacity market, which is a market from which we derive a substantial portion of our revenues, we recognize demand response capacity-based revenue from PJM in September at the end of the four month delivery period of June through September. This typically results in higher revenues in the third quarter as compared to our first, second and fourth quarters.

Employees

As of December 31, 2012, we had 685 full-time employees, including 212 in sales and marketing, 90 in research and development and 383 in general and administrative, including operations. Of these full-time employees, 643 were located in the United States with 350 located in New England, 150 located in California, and the remaining full-time employees located in other areas across the United States. In addition, we had 23 full-time employees located in Australia, eleven located in Canada, five located in New Zealand and three located in the United Kingdom. We expect to grow our employee base, and our future success will depend in part on our ability to attract, retain and motivate highly qualified personnel, for whom competition is intense. Our employees are not represented by any labor unions or covered by a collective bargaining agreement and we have not experienced any work stoppages. We consider our relations with our employees to be good.

Available Information

We were incorporated in Delaware on June 5, 2003 and have our corporate headquarters at 101 Federal Street, Suite 1100, Boston, Massachusetts 02110. We operated as EnerNOC, LLC, a New Hampshire limited liability company, from December 2001 until June 2003. We conduct operations and maintain a number of domestic and international subsidiaries. We also maintain ENOC Securities Corporation, a Massachusetts securities corporation, to invest our cash balances on a short-term basis. Our Internet website address is www.enernoc.com. The information contained on our website is not incorporated by reference into, and does not form any part of, this Annual Report on Form 10-K. We have included our website address as a factual reference and do not intend it to be an active link to our website. Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, or the Exchange Act, are available free of charge through the investor relations page of our internet website as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission, or the SEC.

Item 1A. Risk Factors

The statements contained in this section, as well as statements described elsewhere in this Annual Report on Form 10-K or in our other SEC filings, describe risks that could materially and adversely affect our business, financial condition and results of operations and the trading price of our securities. These risks are not the only risks that we face. Our business, financial condition and results of operations could also be materially affected by additional factors that are not presently known to us or that we currently consider to be immaterial to our operations.

Risks Related to Our Business

Our future profitability is uncertain and we may continue to incur net losses in the future.

As of December 31, 2012, we had an accumulated deficit of $103.4 million. For the year ended December 31, 2012, we incurred a net loss of $22.3 million. Although we achieved profitability for the year ended December 31, 2010, with net income of $9.6 million, we incurred net losses for all other fiscal years since our inception, including the year ended December 31, 2012. Our operating losses have historically been driven by start-up costs, costs of developing our technology including new product and service offerings, and operating expenses related to increased headcount and the expansion of the number of MW under our management. As we seek to grow our revenues and customer base, we plan to continue to invest in our business and employee base in order to capitalize on emerging opportunities and expand our energy management applications, services and products, which will require increased operating expenses. Although we believe we will be able to grow our revenues at rates that will allow us to achieve profitability again in the future, these increased operating expenses, as well as other factors, may cause us to incur net losses in the near term.

A substantial majority of our revenues are and have been generated from open market program sales to a certain electric power grid operator customer, and the modification or termination of this open market program or sales relationship, or the modification or termination of a sales relationship with any future significant electric power grid operator or utility customer could materially and adversely affect our business.

During the years ended December 31, 2012, 2011 and 2010, revenues generated from open market sales to PJM, an electric power grid operator customer, accounted for 40%, 53% and 60%, respectively, of our total revenues. The modification or termination of our sales relationship with PJM, or the modification or termination of any of PJM's open market programs in which we participate, including limitations on our ability to effectively manage our portfolio of demand response capacity, could significantly reduce our future revenues and profit margins and have a material adverse effect on our results of operations and financial condition. For example, in June 2012, PJM discontinued its Interruptible Load for Reliability program, or ILR program, which is a program in which we had historically been an active participant. The discontinuance of the ILR program by PJM reduced the flexibility that we had to manage our portfolio of demand response capacity in the PJM market and impacted our revenues and profit margins. In addition, in February 2012, the Federal Energy Regulatory Commission, or FERC, issued an order substantially accepting a proposal by PJM regarding certain market rule changes with respect to capacity compliance measurement and verification of demand response resources in the PJM capacity market, which we refer to as the PJM proposal. The FERC order resulted in the immediate implementation of the PJM proposal. As a result, our revenues and profit margins and our results of operations and financial condition were and may continue to be negatively impacted, although we expect these impacts to be offset due to improved management of our portfolio of demand response capacity, including the adjustment of our zonal capacity obligations through our participation in PJM incremental auctions, and our future growth in MW in the PJM market.

If we fail to obtain favorable prices in the open market programs in which we currently participate or choose to participate in the future, specifically in the PJM market, our revenues, gross profits and profit margins will be negatively impacted.

In open market programs, electric power grid operators and utilities generally seek bids from companies such as ours to provide demand response capacity based on prices offered in competitive bidding. These prices may be subject to volatility due to certain market conditions or other events, and, as a result, the prices offered to us for this demand response capacity may be significantly lower than historical prices. For example, prior open market auctions of capacity in the PJM market in which we currently participate resulted in prices that were significantly lower than those achieved historically. Accordingly, our revenues, gross profits and profit margins were adversely affected in 2012 as the lower capacity prices in the PJM market took effect for that year. To the extent we are subject to other similar price reductions in the future, our revenues, gross profits and profit margins could be further negatively impacted. In addition, we may alter our participation in both new markets and in markets in which we currently offer our energy management applications, services and products, including by determining not to participate in open market bids to provide demand response capacity. We also may be subject to reduced capacity prices or be unable to participate in certain open market programs for a period of time to the extent that our bidding strategy fails to produce favorable results. In addition, adverse changes in the general economic and market conditions in the regions in which we provide demand response capacity may result in a reduced demand for electricity, resulting in lower prices for capacity, both demand-side and supply-side, for the foreseeable future, which could materially and adversely affect our results of operations and financial condition.

Unfavorable regulatory decisions, changes to the market rules applicable to the programs in which we currently participate or may participate in the future, and varying regulatory structures in certain regional electric power markets could negatively affect our business and results of operations.

Unfavorable regulatory decisions in markets where we currently operate or choose to operate in the future could also significantly and negatively affect our business. For example, in February 2012 FERC issued an order substantially accepting the PJM proposal, which resulted in the immediate implementation of PJM's proposed market rule changes regarding capacity compliance measurement and verification. As a result, our future revenues and profit margins with respect to the PJM region may be reduced and our future results of operations and financial condition may be negatively impacted, although we expect these impacts to be offset by the effective management of our portfolio of demand response capacity, including the adjustment of our zonal capacity obligations through our participation in PJM incremental auctions, and our future growth in MW in the PJM market. In addition, to the extent that PJM or any other grid operator or utility customer is successful at modifying any program or market rules in the future in a manner adverse to our business, our future revenues and profit margins may be significantly reduced and our future results of operations and financial condition could be further negatively impacted. Market rules could also be modified to change the design of, or pricing related to a particular demand response program, which may adversely affect our participation in that program or cause us to cease participation in that program altogether, or a demand response program in which we currently participate could be eliminated in its entirety and replaced with a new program that is more expensive for us to operate. Any elimination or change in the design of a demand response program, including any supplemental program or market rule, could adversely impact our ability to successfully manage our portfolio of demand response capacity in that program, especially in the PJM market where we have substantial operations, and could have a material adverse effect on our results of operations and financial condition.

Regulators could also modify market rules in certain areas to further limit the use of back-up generators in demand response markets or could implement bidding floors or caps that could lower our revenue opportunities. For example, the Environmental Protection Agency, or the EPA, recently issued a final rule in the National Environmental Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines that will allow emergency generators to participate in emergency demand response programs for up to 100 hours per year. In the event this final rule is challenged, and such challenge results in a decrease to the 100 hour per year limit for, or the elimination of any, participation by emergency generators in emergency demand response programs, some of the demand response capacity reductions that we aggregate from C&I customers willing to reduce consumption from the electric power grid by activating their own back-up generators during demand response events would not qualify as capacity without the addition of certain emissions reduction equipment. If this were to occur, we would have to find alternative sources of capacity to meet our capacity obligations to our electric power grid operator and utility customers. If we were unable to procure additional sources of capacity to meet these obligations, our business and results of operations could be negatively impacted.

The electric power industry is highly regulated. The regulatory structures in regional electricity markets are varied and some regulatory requirements make it more difficult for us to provide some or all of our energy management applications, services and products in those regions. For instance, in some markets, regulated quantity or payment levels for demand response capacity or energy make it more difficult for us to cost-effectively enroll and manage many C&I customers in demand response programs. Further, some markets have regulatory structures that do not yet include demand response as a qualifying resource for purposes of short-term reserve requirements known as ancillary services. As part of our business strategy, we intend to expand into additional regional electricity markets. However, unfavorable regulatory structures could limit the number of regional electricity markets available to us for expansion.

In addition, a buildup of new electric generation facilities or reduced demand for electric capacity could result in excess electric generation capacity in certain regional electric power markets. Excess electric generation capacity and unfavorable regulatory structures could lower the value of demand response services and limit the number of economically attractive regional electricity markets that are available to us for expansion, which could negatively impact our business and results of operations.

The success of our business depends in part on our ability to develop new energy management applications, services and products and increase the functionality of our current energy management applications, services and products.

The market for our energy management applications, services and products is characterized by rapid technological changes, frequent new software introductions, Internet-related technology enhancements, uncertain product life cycles, changes in customer demands and evolving industry standards and regulations. We may not be able to successfully develop and market new energy management applications, services and products that comply with present or emerging industry regulations and technology standards. Also, any new or modified regulation or technology standard could increase our cost of doing business.

From time to time, our customers have expressed a need for increased functionality in our energy management applications, services and products. In response, and as part of our strategy to enhance our energy management applications, services and products and grow our business, we plan to continue to make substantial investments in the research and development of new technologies. Our future success will depend in part on our ability to continue to design and sell new, competitive energy management applications, services and products and enhance our existing energy management applications, services and products. Initiatives to develop new energy management applications, services and products will require continued investment, and we may experience unforeseen problems in the performance of our technologies and operational processes, including new technologies and operational processes that we develop and deploy, to implement our energy management applications, services and products. In addition, software addressing our energy management applications, services and products is complex and can be expensive to develop, and new software and software enhancements can require long development and testing periods. If we are unable to develop new energy management applications, services and products or enhancements to our existing energy management applications, services and products on a timely basis, or if the market does not accept our new or enhanced energy management applications, services and products, we will lose opportunities to realize revenues and obtain customers, and our business and results of operations will be adversely affected.

We depend on the electric power industry for revenues and, as a result, our operating results have experienced, and may continue to experience, significant variability due to volatility in electric power industry spending and other factors affecting the electric utility industry, such as seasonality of peak demand and overall demand for electricity.

We derive recurring revenues from the sale of our energy management applications, services and products, directly or indirectly, to the electric power industry. Purchases of our demand response application and services by electric power grid operators or utilities may be deferred, cancelled or otherwise negatively impacted as a result of many factors, including challenging economic conditions, mergers and acquisitions involving these entities, fluctuations in interest rates and increased electric utility capital spending on traditional supply-side resources. In addition, sales of our energy management applications, services and products to electric power grid operator and utility customers may be negatively impacted by changing regulations and program rules, which could have a material adverse effect on our results of operations and financial condition.

Sales of demand response capacity in open market bidding programs are particularly susceptible to variability based on changes in the spending patterns of our electric power grid operator and utility customers and on associated fluctuating market prices for capacity. In addition, peak demand for electricity and other capacity constraints tend to be seasonal. Peak demand in the United States tends to be most extreme in warmer months, which may lead some demand response capacity markets to yield higher prices for demand response capacity or contract for the availability of a greater amount of demand response capacity during these warmer months. As a result, our demand response revenues may be seasonal. For example, in the PJM forward capacity market, which is a market from which we derive a substantial portion of our revenues, we recognize capacity-based revenue from PJM during the third quarter of our fiscal year. This will result in higher revenues in our third quarter as compared to our other fiscal quarters. As a result of this seasonality, we believe that quarter to quarter comparisons of our operating results are not necessarily meaningful and that these comparisons cannot be relied upon as indicators of future performance.

Further, occasional events, such as a spike in natural gas prices or potential decreases in availability, can lead electric power grid operators and utilities to implement short-term calls for demand response capacity to respond to these events, but we cannot be sure that such calls will occur or that we will be in a position to generate revenues when they do occur. In addition, given the current economic slowdown and the related potential reduction in demand for electricity, there can be no assurance that there will not be a corresponding reduction in the implementation of both supply and demand-side resources by electric power grid operators and utilities. We have experienced, and may in the future experience, significant variability in our revenues, on both an annual and a quarterly basis, as a result of these and other factors. Pronounced variability or an extended period of reduction in spending by electric power grid operators and utilities could negatively impact our business and make it difficult for us to accurately forecast our future sales.

The $50 million credit facility that we and one of our subsidiaries entered into with Silicon Valley Bank, or SVB, in March 2012, which we amended in June 2012 and which we refer to as the 2012 credit facility, contains financial and operating restrictions that may limit our access to credit. If we fail to comply with covenants contained in the 2012 credit facility, we may be required to repay our indebtedness thereunder. In addition, if we fail to extend, renew or replace the 2012 credit facility and we still have letters of credit issued and outstanding when it matures on April 15, 2013, we will be required to post up to 105% of the value of the letters of credit in cash with the bank to collateralize those letters of credit. Either of these conditions may have a material adverse effect on our liquidity.

Provisions in the 2012 credit facility impose restrictions on our ability to, among other things:

- incur additional indebtedness;
- create liens;
- enter into transactions with affiliates;
- transfer assets;
- make certain acquisitions;
- pay dividends or make distributions on, or repurchase, EnerNOC stock;
- merge or consolidate; or
- undergo a change of control.

In addition, we are required to meet certain financial covenants customary with this type of credit facility, including maintaining minimum earnings levels and a minimum specified ratio of current assets to current liabilities. The 2012 credit facility also contains other customary covenants. We may not be able to comply with these covenants in the future. Our failure to comply with these covenants may result in the declaration of an event of default and could cause us to be unable to borrow under the 2012 credit facility. In addition to preventing additional borrowings under the 2012 credit facility, an event of default, if not cured or waived, may result in the acceleration of the maturity of indebtedness outstanding under the 2012 credit facility, which would require us to pay all amounts outstanding. In addition, in the event that we default under the 2012 credit facility while we have letters of credit outstanding, we will be required to post up to 105% of the value of the letters of credit in cash with SVB to collateralize those letters of credit. Furthermore, the 2012 credit facility matures on April 15, 2013. If we fail to extend, renew or replace the 2012 credit facility when it matures, and we still have letters of credit issued and outstanding, we will be required to post up to 105% of the value of the letters of credit in cash with SVB to collateralize those letters of credit.

As of December 31, 2012, we were in compliance with all of the covenants under the 2012 credit facility and were contingently liable for $42.6 million in connection with outstanding letters of credit that were issued under the 2012 credit facility. If an event of default occurs, we may not be able to cure it within any applicable cure period, if at all. If the maturity of our indebtedness is accelerated, we may not have sufficient funds available for repayment or collateralization of our letters of credit. In addition, we may not have the ability to borrow or obtain sufficient funds to replace the accelerated indebtedness on terms acceptable to us, or at all.

The expiration of our existing utility contracts without obtaining renewal or replacement utility contracts could negatively impact our business by reducing our revenues and profit margins, thereby having a material adverse effect on our results of operations and financial condition.

We have entered into utility contracts with our electric power grid operator and utility customers in different geographic regions in the United States, as well as in Australia, Canada, New Zealand and the United Kingdom, and are regularly in discussions to enter into new utility contracts with electric power grid operators and utilities. However, there can be no assurance that we will be able to renew or extend our existing utility contracts or enter into new utility contracts on favorable terms, if at all. If, upon expiration, we are unable to renew or extend our existing utility contracts and are unable to enter into new utility contracts, our future revenues and profit margins could be significantly reduced, which could have a material adverse effect on our results of operations and financial condition.

An increased rate of terminations by our C&I customers, or their failure to renew contracts when they expire, would negatively impact our business by reducing our revenues and requiring us to spend more money to maintain and grow our C&I customer base.

Our ability to provide demand response capacity under our utility contracts and in open market bidding programs depends on the amount of MW that we manage across C&I customers who enter into contracts with us to reduce electricity consumption on demand. If our existing C&I customers do not renew their contracts as they expire, we will need to acquire MW from additional C&I customers or expand our relationships with existing C&I customers in order to maintain our revenues and grow our business. The loss of revenues resulting from C&I customer contract terminations or expirations could be significant, and limiting C&I customer terminations is an important factor in our ability to return to profitability in future periods. If we are unsuccessful in limiting our C&I customer terminations, we may be unable to acquire a sufficient amount of MW or we may incur significant costs to replace MW in our portfolio, which could cause our revenues to decrease and our cost of revenues to increase.

We face pricing pressure relating to electric capacity made available to electric power grid operators and utilities and in the percentage or fixed amount paid to C&I customers for making capacity available, which could adversely affect our results of operations and financial condition.

The rapid growth of the energy management applications, services and products sector is resulting in increasingly aggressive pricing, which could cause the prices in that sector to decrease over time. Our electric power grid operator and utility customers may switch to other energy management applications, services and products providers based on price, particularly if they perceive the quality of our competitors' products or services to be equal or superior to ours. Continued decreases in the price of demand response capacity by our competitors could result in a loss of electric power grid operator and utility customers or a decrease in the growth of our business, or it may require us to lower our prices for capacity to remain competitive, which would result in reduced revenues and lower profit margins and would adversely affect our results of operations and financial condition. Continued increases in the percentage or fixed amount paid to C&I customers by our competitors for making capacity available could result in a loss of C&I customers or a decrease in the growth of our business. It also may require us to increase the percentage or fixed amount we pay to our C&I customers to remain competitive, which would result in increases in the cost of revenues and lower profit margins and would adversely affect our results of operations and financial condition.

We face risks related to our expansion into international markets.

We intend to expand our addressable market by pursuing opportunities to provide our energy management applications, services and products in international markets. Accordingly, new markets may require us to respond to new and unanticipated regulatory, marketing, sales and other challenges. There can be no assurance that we will be successful in responding to these and other challenges we may face as we enter and attempt to expand in international markets. International operations also entail a variety of other risks, including:

- unexpected changes in legislative, regulatory or market requirements of foreign countries;
- currency exchange fluctuations;
- longer payment cycles and greater difficulty in accounts receivable collection; and
- significant taxes or other burdens of complying with a variety of foreign laws.

International operations are also subject to general geopolitical risks, such as political, social and economic instability and changes in diplomatic and trade relations. One or more of these factors could adversely affect any international operations and result in lower revenue than we expect and could significantly affect our results of operations and financial condition.

We may not be able to identify suitable acquisition candidates or complete acquisitions successfully, which may inhibit our rate of growth, and acquisitions that we complete may expose us to a number of unanticipated operational and financial risks.

In addition to organic growth, we intend to continue to pursue growth through the acquisition of companies or assets that may enable us to enhance our technology and capabilities, expand our geographic market, add experienced management personnel and increase our service offerings. However, we may be unable to implement this growth strategy if we cannot identify suitable acquisition candidates, reach agreement on potential acquisitions on acceptable terms, successfully integrate personnel or assets that we acquire or for other reasons. Our acquisition efforts may involve certain risks, including:

- an acquisition may involve unexpected costs or liabilities, may cause us to fail to meet our previously stated financial guidance, or the effects of purchase accounting may be different from our expectations;
- problems may arise with our ability to successfully integrate the acquired businesses, which may result in us not operating as effectively and efficiently as expected, and may include:
  - diversion of management time, as well as a shift of focus from operating the businesses to issues related to integration and administration or inadequate management resources available for integration activity and oversight;
  - failure to retain and motivate key employees;
  - failure to successfully manage relationships with customers and suppliers;
  - failure of customers to accept our new energy management applications, services and products;
  - failure to effectively coordinate sales and marketing efforts;
  - failure to combine service offerings quickly and effectively;
  - failure to effectively enhance acquired technology, applications, services and products or develop new applications, services and products relating to the acquired businesses;

- difficulties and inefficiencies in managing and operating businesses in multiple locations or operating businesses in which we have either limited or no direct experience;
- difficulties integrating financial reporting systems;
- difficulties in the timely filing of required reports with the SEC; and
- difficulties in implementing controls, procedures and policies, including disclosure controls and procedures and internal controls over financial reporting, appropriate for a larger public company at companies that, prior to their acquisition, lacked such controls, procedures and policies, which may result in ineffective disclosure controls and procedures or material weaknesses in internal controls over financial reporting;

- we may not be able to achieve the expected synergies from an acquisition, or it may take longer than expected to achieve those synergies;
- an acquisition may result in future impairment charges related to diminished fair value of businesses acquired as compared to the price we paid for them;
- an acquisition may involve restructuring operations or reductions in workforce, which may result in substantial charges to our operations; and
- future acquisitions could result in potentially dilutive issuances of equity securities, the incurrence of debt, or contingent liabilities, which could harm our financial condition.

We may be subject to governmental or regulatory investigations or audits and may incur significant penalties and fines if found to be in non-compliance with any applicable State or Federal regulation.

While the electric power markets in which we operate are regulated, most of our business is not directly subject to the regulatory framework applicable to the generation and transmission of electricity. However, regulations by FERC related to market design, market rules, tariffs, and bidding rules impact how we can interact with our electric power grid operator and utility customers. In addition, we may be subject to governmental or regulatory investigations or audits from time to time in connection with our participation in certain demand response programs. For example, we were recently the subject of two investigations by FERC, the first of which addressed unintentional meter data errors associated with a small number of our demand response sites in the ISO-NE market and the second of which addressed the failure by our wholly-owned subsidiary, Celerity Energy Partners San Diego, LLC, or Celerity, to make two FERC filings in a timely manner in 2010. Although the investigations by FERC, which concluded in December 2012, did not have a material adverse effect on our business, financial condition or results of operations, any similar investigation could result in a material adjustment to our historical financial statements and may have a material adverse effect on our results of operations and financial condition. As part of any regulatory investigation or audit, FERC or any other governmental or regulatory entity may review our performance under our utility contracts and open market bidding programs, cost structures, and compliance with applicable laws, regulations and standards. If an investigation or audit uncovers improper or illegal activities, we may be subject to civil and criminal penalties and administrative sanctions, in addition to any negative publicity associated with any such penalties or sanctions, which could have a material adverse effect on our results of operations and financial condition.

Our business is subject to government regulation and may become subject to modified or new government regulation, which may negatively impact our ability to sell and market our energy management applications, services and products.

While the electric power markets in which we operate are regulated, most of our business is not directly subject to the regulatory framework applicable to the generation and transmission of electricity, with the exception of Celerity, which exports power to the electric power grid and is thus subject to direct regulation by FERC and its regulations related to the sale of wholesale power at market based rates. However, we may become directly subject to the regulation of FERC to the extent we are deemed to own, operate, or control generation used to make wholesale sales of power or provide ancillary services that involve a sale of electric energy or capacity for resale, or the export of power to the electric power grid. In addition, in an order issued in January

2010, FERC noted that when a demand response resource makes sales of energy for resale, the resource may become subject to direct regulation by FERC. Although we do not expect any further clarification by FERC of its jurisdiction over demand response activities to have a material adverse effect on our consolidated financial condition, results of operations or cash flows, we may become subject to other new or modified government regulations that could have a material adverse effect on our results of operations and financial condition.

The installation of devices or the activation of electric generators used in providing our energy management applications, services and products may be subject to governmental oversight and regulation under state and local ordinances relating to building codes, public safety regulations pertaining to electrical connections, security protocols, and local and state licensing requirements. In a relatively few instances, we have agreed to own and operate a back-up generator at a C&I customer site for a period of time and to activate the generator when capacity is called for dispatch so that the C&I customer can reduce its consumption of electricity from the electric power grid. These generators are ineligible to participate in demand response programs in certain regions, and in others they may become ineligible to participate in the future or may be compensated less for such participation, thereby reducing our revenues and adversely affecting our financial condition.

In addition, certain of our utility contracts and expansion of existing utility contracts are subject to approval by federal, state, provincial or local regulatory agencies. There can be no assurance that such approvals will be obtained or be issued on a timely basis, if at all. Additionally, federal, state, provincial or local governmental entities may seek to change existing regulations, impose additional regulations or change their interpretation of the applicability of existing regulations. Any modified or new government regulation applicable to our current or future energy management applications, services and products, whether at the federal, state, provincial or local level, may negatively impact the installation, servicing and marketing of, and increase our costs and the price related to, our energy management applications, services and products. In addition, despite our efforts to manage compliance with any other regulations to which we are subject, we may be found to be in non-compliance with such regulations and therefore subject to penalties or fines, which could have a material adverse effect on our business, financial condition and results of operations.

Failure of third parties to manufacture or install quality products or provide reliable services in a timely manner or at all could cause delays in the delivery of our energy management applications, services and products, or could result in a failure to provide accurate data to our electric power grid operator and utility customers, which could damage our reputation, cause us to lose customers and have a material adverse effect on our business results of operations and financial condition.

Our success depends on our ability to provide quality, reliable, and secure energy management applications, services and products in a timely manner, which in part requires the proper functioning of facilities and equipment owned, operated, installed or manufactured by third parties upon which we depend. For example, our reliance on third parties includes:

- utilizing components that we or third parties install or have installed at C&I customer sites;
- relying on metering information provided by third parties to accurately and reliably provide customer data to our electric power grid operator and utility customers;
- outsourcing email notification and cellular and paging wireless communications that are used to notify our C&I customers of their need to reduce electricity consumption at a particular time and to execute instructions to devices installed at our C&I customer sites that are programmed to automatically reduce consumption on receipt of such secure communications; and
- outsourcing certain installation and maintenance operations to third-party providers.

Any delays, malfunctions, inefficiencies or interruptions in these products, services or operations could adversely affect the reliability or operation of our energy management applications, services and products, which could cause us to experience difficulty monitoring or retaining current customers and attracting new customers. Any errors in metering information provided to us by third parties, including electric power grid operators and utilities, could also adversely affect the customer data that we provide to our electric power grid operator and utility customers. Such delays and errors could result in an overpayment or underpayment to us and our C&I customers from our electric power grid operator and utility customers, which in some instances may cause us to violate certain market rules and require us to make refunds to our electric power grid operator and utility customers and pay associated penalties or fines. In addition, in such instances our brand, reputation and growth could be negatively impacted.

We have a limited operating history in an emerging market, which may make it difficult to evaluate our business and prospects, and may expose us to increased risks and uncertainties.

We were incorporated as a Delaware corporation in June 2003 and first began generating revenues in 2003. Accordingly, we have only a limited history of generating revenues, and the future revenue potential of our business in the emerging market for energy management applications, services and products is uncertain. As a result of our relatively short operating history, we have limited financial data that can be used to evaluate our business, strategies, performance and prospects or an investment in our common stock. Any evaluation of our business and our prospects must be considered in light of our limited operating history and the risks and uncertainties encountered by companies in an emerging market. To address these risks and uncertainties, we must do the following:

- maintain our current relationships and develop new relationships with electric power grid operators and utilities and the entities that regulate them;
- maintain and expand our current relationships and develop new relationships with C&I customers;
- maintain and enhance our existing energy management applications, services and products, and technology systems;
- continue to develop energy management applications, services and products that achieve significant market acceptance;
- continue to enhance our information processing systems;
- execute our business and marketing strategies successfully, including accurately nominating demand response capacity in the programs in which we participate, and delivering a high level of performance by assisting our C&I customers to reduce their energy usage during demand response events;
- respond to competitive developments;
- attract, integrate, retain and motivate qualified personnel; and
- continue to participate in shaping the regulatory environment.

We may be unable to accomplish one or more of these objectives, which could cause our business to suffer. In addition, accomplishing many of these goals might be very expensive, which could adversely impact our operating results and financial condition. Any predictions about our future operating results may not be as accurate as they could be if we had a longer operating history and if the market in which we operate was more mature.

Our results of operations could be adversely affected if our operating expenses and cost of sales do not correspond with the timing of our revenues.

Most of our operating expenses, such as employee compensation and rental expense for properties, are either relatively fixed in the short-term or incurred in advance of sales. Moreover, our spending levels are based in part on our expectations regarding future revenues. As a result, if revenues for a particular quarter are below expectations, we may not be able to proportionately reduce operating expenses for that quarter. For example, if a demand response event or metering and verification test does not occur in a particular quarter, we may not be able to recognize revenues for the undemonstrated capacity in that quarter. This shortfall in revenues could adversely affect our operating results for that quarter and could cause the market price of our common stock to decline substantially.

We incur significant up-front costs associated with the expansion of the number of MW and the infrastructure necessary to enable those MW. In most of the markets in which we originally focused our growth, we generally begin earning revenues from our MW shortly after enablement. However, in certain forward capacity markets in which we participate or may choose to participate in the future, it may take longer for us to begin earning revenues from MW that we enable, in some cases up to a year after enablement. For example, the PJM forward capacity market, which is a market from which we derive a substantial portion of our revenues, operates on a June to May program-year basis, which means that a MW that we enable after June of each year will typically not be recognized until September of the following year. The up-front costs we incur to expand our MW in PJM and other similar markets, coupled with the delay in receiving revenues from those MW, could adversely affect our operating results and could cause the market price of our common stock to decline substantially.

We operate in highly competitive markets; if we are unable to compete successfully, we could lose market share and revenues.

The market for energy management applications, services and products is fragmented. Some traditional providers of advanced metering infrastructure services have added, or may add, demand response or other energy management applications, services and products to their existing business. We face strong competition from other energy management service providers, both larger and smaller than we are. We also compete against traditional supply-side resources such as natural gas-fired peaking power plants. In addition, utilities and competitive electricity suppliers offer their own energy management applications, services and products, which could decrease our base of potential customers and revenues and have a material adverse effect on our results of operations and financial condition.

Many of our competitors and potential competitors have greater financial resources than we do. Our competitors could focus their substantial financial resources to develop a competing business model or develop products or services that are more attractive to potential customers than what we offer. Some advanced metering infrastructure service providers, for example, are substantially larger and better capitalized than we are and have the ability to combine advanced metering and demand response services into an integrated offering to a large, existing customer base. Our competitors may offer energy management applications, services and products at prices below cost or even for free in order to improve their competitive positions. Any of these competitive factors could make it more difficult for us to attract and retain customers, cause us to lower our prices in order to compete, and reduce our market share and revenues, any of which could have a material adverse effect on our financial condition and results of operations. In addition, we may also face competition based on technological developments that reduce peak demand for electricity, increase power supplies through existing infrastructure or that otherwise compete with our energy management applications, services and products.

If the actual amount of demand response capacity that we make available under our capacity commitments is less than required, our committed capacity could be reduced and we could be required to make refunds or pay penalty fees, which could negatively impact our results of operations and financial condition.

We provide demand response capacity to our electric power grid operator and utility customers either under utility contracts or under terms established in open market bidding programs where capacity is purchased. Under the utility contracts and open market bidding programs, electric power grid operators and utilities make periodic payments to us based on the amount of demand response capacity that we are obligated to make available to them during the contract period, or make periodic payments to us based on the amount of demand response capacity that we bid to make available to them during the relevant period. We refer to these payments as committed capacity payments. Committed capacity is negotiated and established by the utility contract or set in the open market bidding process and is subject to subsequent confirmation by measurement and verification tests or performance in a demand response event. In our open market bidding programs, we offer different amounts of committed capacity to our electric power grid operator and utility customers based on market rules on a periodic basis. We refer to measured and verified capacity as our demonstrated or proven capacity. Once demonstrated, the proven capacity amounts typically establish a baseline of capacity for each C&I customer site in our portfolio, on which committed capacity payments are calculated going forward and until the next demand response event or measurement and verification test when we are called upon to make capacity available.

Under some of our utility contracts and in certain open market bidding programs, any difference between our demonstrated capacity and the committed capacity on which capacity payments were previously made will result in either a refund payment from us to our electric power grid operator or utility customer or an additional payment to us by such customer. Any refund payable by us would reduce our deferred revenues, but would not impact our previously recognized revenues. If there is a refund payment due to an electric power grid operator or utility customer, we generally make a corresponding adjustment in our payments to the C&I customer or customers who failed to make the appropriate level of capacity available, however we are sometimes unable to do so. In addition, some of our utility contracts with, and open market programs established by, our electric power grid operator and utility customers provide for penalty payments, which could be substantial, in certain circumstances in which we do not meet our capacity commitments, either in measurement and verification tests or in demand response events. Further, because measurement and verification test results for some utility contracts and in certain open market bidding programs establish capacity levels on which payments will be made until the next measurement and verification test or demand response event, the payments to be made to us under these utility contracts and open market bidding programs could be reduced until the level of capacity is established at the next measurement and verification test or demand response event. We could experience significant period-to-period fluctuations in our financial results in future periods due to any refund or penalty payments, capacity payment adjustments, replacement costs or other payments made to our electric power grid operator or utility customers, which could be substantial. We incurred aggregate net penalty payments of $1.9 million, $0.7 million, and $0.3 million during the years ended December 31, 2012, 2011 and 2010, respectively.

Our ability to achieve our committed capacity depends on the performance of our C&I customers, and the failure of these customers to make the appropriate levels of capacity available when called upon could cause us to make refund payments to, or incur penalties imposed by, our electric power grid operator and utility customers.

The capacity level that we are able to achieve is dependent upon the ability of our C&I customers to curtail their energy usage when called upon by us during a demand response event or a measurement and verification test. Certain demand response programs in which we currently participate or choose to participate in the future may have rigorous requirements, making it difficult for our C&I customers to perform when called upon by us. For example, if PJM dispatches a measurement and verification test and our C&I customers fail to perform or perform in a deficient manner, we may be subject to substantial penalties given that we have enrolled a significant number of MW in the PJM demand response market. In the event that our C&I customers are unable to perform or perform at levels below which they agreed to perform, we may be unable to achieve our committed capacity levels and may be subject to the refunds or penalties described in the risk factor above, which could have a material adverse effect on our results of operations and financial condition. The capacity level that we are able to achieve also varies with the electricity demand of targeted equipment, such as heating and cooling equipment, at the time a C&I customer is called to perform. Accordingly, our ability to deliver committed capacity depends on factors beyond our control, such as the temperature and humidity, and then-current electricity use by our C&I customers when those C&I customers are called to perform. The correct operation of, and timely communication with, devices used to control equipment are also important factors that affect available capacity.

If we fail to successfully educate existing and potential electric power grid operator and utility customers regarding the benefits of our energy management applications, services and products or a market otherwise fails to develop for those applications, services and products, our ability to sell our energy management applications, services and products and grow our business could be limited.

Our future success depends on commercial acceptance of our energy management applications, services and products and our ability to enter into additional utility contracts and new open market bidding programs. We anticipate that revenues related to our demand response application and services will constitute a substantial majority of our revenues for the foreseeable future. The market for energy management applications, services and products in general is relatively new. If we are unable to educate our potential customers about the advantages of our energy management applications, services and products over competing products and services, or our existing customers no longer rely on our energy management applications, services and products, our ability to sell our energy management applications, services and products will be limited. In addition, because the energy management applications, services and products sector is rapidly evolving, we cannot accurately assess the size of the market, and we may have limited insight into trends that may emerge and affect our business. For example, we may have difficulty predicting customer needs and developing energy management applications, services and products that address those needs. Further, we are subject to the risk that the current global economic and market conditions will result in lower overall demand for electricity in the United States and other markets that we are seeking to penetrate over the next few years. Such a reduction in the demand for electricity could create a corresponding reduction in both supply-and demand-side resources being implemented by electric power grid operators and utilities. If the market for our energy management applications, services and products does not continue to develop, our ability to grow our business could be limited and we may not be able to operate profitably.

We expect to continue to expand our sales and marketing, operations, and research and development capabilities, as well as our financial and reporting systems, and as a result we may encounter difficulties in managing our growth, which could disrupt our operations.

We expect to experience continued growth in the number of our employees and significant growth in the scope of our operations. To manage our anticipated future growth, we must continue to implement and improve our managerial, operational, financial and reporting systems, improve our internal controls, procedures and compliance programs, expand our facilities, and continue to recruit and train additional qualified personnel. All of these measures will require significant expenditures and will demand the attention of management. Due to our limited resources, we may not be able to effectively manage the expansion of our operations, implement sufficient internal controls, procedures or compliance programs, or recruit and adequately train additional qualified personnel. The physical expansion of our operations may lead to significant costs and may divert our management and business development resources. Any inability to manage growth could delay the execution of our business plans or disrupt our operations.

We allocate our operations, sales and marketing, research and development, general and administrative, and financial resources based on our business plan, which includes assumptions about current and future utility contracts and open market programs with electric power grid operator and utility customers, current and future contracts with C&I customers, variable prices in open market programs for demand response capacity, the development of ancillary services markets which enable demand response as a revenue generating resource and a variety of other factors relating to electricity markets, and the resulting demand for our energy management applications, services and products. However, these factors are uncertain. If our assumptions regarding these factors prove to be incorrect or if alternatives to those offered by our energy management applications, services and products gain further acceptance, then actual demand for our energy management applications, services and products could be significantly less than the demand we anticipate and we may not be able to sustain our revenue growth or return to profitability in future periods.

We may require significant additional capital to pursue our growth strategy, but we may not be able to obtain additional financing on acceptable terms or at all.

The growth of our business will depend on substantial amounts of additional capital for posting financial assurances in order to enter into utility contracts and open market bidding programs with electric power grid operators and utilities, and marketing and product development of our energy management applications, services and products. Our capital requirements will depend on many factors, including the rate of our revenue and sales growth, our introduction of new energy management applications, services and products and enhancements to our existing energy management applications, services and products, and our expansion of sales and marketing and product development activities. In addition, we may consider strategic acquisitions of complementary businesses or technologies to grow our business, which could require significant capital and could increase our capital expenditures related to future operation of the acquired business or technology. Because of our historical losses, we do not fit traditional credit lending criteria. Moreover, the financial turmoil affecting the banking system and financial markets in recent years has resulted in a reduction in the availability of credit in the credit markets, which could adversely affect our ability to obtain additional funding. We may not be able to obtain loans or additional capital on acceptable terms or at all.

If we lose key personnel upon whom we are dependent, or if we fail to attract and retain qualified personnel, we may not be able to manage our operations and meet our strategic objectives.

Our continued success depends upon the continued availability, contributions, vision, skills, experience and effort of our senior management, sales and marketing, research and development, and operations teams. We do not maintain "key person" insurance on any of our employees. We have entered into employment agreements with certain members of our senior management team, but none of these agreements guarantees the services of the individual for a specified period of time. All of the employment arrangements with our key personnel, including the members of our senior management team, provide that employment is at-will and may be terminated by the employee at any time and without notice. The loss of the services of any of our key personnel might impede our operations or the achievement of our strategic and financial objectives. We rely on our research and development team to research, design and develop new and enhanced energy management applications, services and products. We rely on our operations team to install, test, deliver and manage our energy management applications, services and products. We rely on our sales and marketing team to sell our energy management applications, services and products to our customers, build our brand and promote our company. The loss or interruption of the service of members of our senior management, sales and marketing, research and development, or operations teams, or our inability to attract or retain other qualified personnel or advisors could have a material adverse effect on our business, financial condition and results of operations and could significantly reduce our ability to manage our operations and implement our strategy.

An inability to protect our intellectual property could negatively affect our business and results of operations.

Our ability to compete effectively depends in part upon the maintenance and protection of the intellectual property related to our energy management applications, services and products. We hold a few patents and numerous trademarks and copyrights. Patent protection is unavailable for certain aspects of the technology and operational processes that are important to our business. Any patent held by us or to be issued to us, or any of our pending patent applications, could be challenged, invalidated, unenforceable or circumvented. Moreover, some of our trademarks which are not in use may become available to others. To date, we have relied principally on patent, copyright, trademark and trade secrecy laws, as well as confidentiality and proprietary information agreements and licensing arrangements, to establish and protect our intellectual property. However, we have not obtained confidentiality and proprietary information agreements from all of our customers and vendors, and although we have entered into confidentiality and proprietary information agreements with all of our employees, we cannot be certain that these agreements will be honored. Some of our confidentiality and proprietary information agreements may not be in writing, and some customers are subject to laws and regulations that require them to disclose information that we would otherwise seek to keep confidential. Policing unauthorized use of our intellectual property is difficult and expensive, as is enforcing our rights against unauthorized use. The steps that we have taken or may take may not prevent misappropriation of the intellectual property on which we rely. In addition, effective protection may be unavailable or limited in jurisdictions outside the United States, as the intellectual property laws of foreign countries sometimes offer less protection or have onerous filing requirements. From time to time, third parties may infringe our intellectual property rights. Litigation may be necessary to enforce or protect our rights or to determine the validity and scope of the rights of others. Any litigation could be unsuccessful, cause us to incur substantial costs, divert resources away from our daily operations and result in the impairment of our intellectual property. Failure to adequately enforce our rights could cause us to lose rights in our intellectual property and may negatively affect our business.

We may be subject to damaging and disruptive intellectual property litigation related to allegations that our energy management applications, services and products infringe on intellectual property held by others, which could result in the loss of use of those applications, services and products.

Third-party patent applications and patents may relate to our energy management applications, services and products. As a result, third-parties may in the future make infringement and other allegations that could subject us to intellectual property litigation relating to our energy management applications, services and products, which litigation could be time-consuming and expensive, divert attention and resources away from our daily operations, impede or prevent delivery of our energy management applications, services and products, and require us to pay significant royalties, licensing fees and damages. In addition, parties making infringement and other claims may be able to obtain injunctive or other equitable relief that could effectively block our ability to provide our energy management applications, services and products and could cause us to pay substantial damages. In the event of a successful claim of infringement, we may need to obtain one or more licenses from third parties, which may not be available at a reasonable cost, or at all.

If our information technology systems fail to adequately gather, assess and protect data used in providing our energy management applications, services and products, or if we experience an interruption in their operation, our business, financial condition and results of operations could be adversely affected.

The efficient operation of our business is dependent on our information technology systems. We rely on our information technology systems to effectively control the devices which enable our energy management applications, services and products, gather and assess data used in providing our energy management applications, services and products, manage relationships with our customers, and maintain our research and development data. The failure of our information technology systems to perform as we anticipate could disrupt our business and product development and make us unable, or severely limit our ability, to respond to demand response events. In addition, our information technology systems are vulnerable to damage or interruption from:

- earthquake, fire, flood and other natural disasters;
- terrorist attacks and attacks by computer viruses or hackers;
- power loss; and
- computer systems, Internet, telecommunications or data network failure.

Any interruption in the operation of our information technology systems could result in decreased revenues under our contracts and commitments, reduced profit margins on revenues where fixed payments are due to our C&I customers, reductions in our demonstrated capacity levels going forward, customer dissatisfaction and lawsuits and could subject us to penalties, any of which could have a material adverse effect on our business, financial condition and results of operations.

Any internal or external security breaches involving our energy management applications, services and products, and even the perception of security risks involving our energy management applications, services and products or the transmission of data over the Internet, whether or not valid, could harm our reputation and inhibit market acceptance of our energy management applications, services and products and cause us to lose customers.

We use our energy management applications, services and products to compile and analyze sensitive or confidential information related to our customers. In addition, some of our energy management applications, services and products allow us to remotely control equipment at C&I customer sites. Our energy management applications, services and products rely on the secure transmission of proprietary data over the Internet for some of this functionality. Well-publicized compromises of Internet security, or cyberattacks, could have the effect of substantially reducing confidence in the Internet as a medium of data transmission. The occurrence or perception of security breaches in our energy management applications, services and products or our customers' concerns about Internet security or the security of our energy management applications, services and products, whether or not they are warranted, could have a material adverse effect on our business, harm our reputation, inhibit market acceptance of our energy management applications, services and products and cause us to lose customers, any of which could have a material adverse effect on our financial condition and results of operations.

We may come into contact with sensitive consumer information or data when we perform operational, installation or maintenance functions for our customers. Even the perception that we have improperly handled sensitive, confidential information could have a negative effect on our business. If, in handling this information, we fail to comply with privacy or security laws, we could incur civil liability to government agencies, customers and individuals whose privacy is compromised. In addition, third parties may attempt to breach our security or inappropriately use our energy management applications, services and products, particularly as we grow our business, through computer viruses, electronic break-ins and other disruptions. We may also face a security breach or electronic break-in by one of our employees or former employees. If a breach is successful, confidential information may be improperly obtained, and we may be subject to lawsuits and other liabilities.

Global economic and credit market conditions, and any associated impact on spending by electric power grid operators and utilities or on the continued operations of our C&I customers, could have a material adverse effect on our business, operating results, and financial condition.

Volatility and disruption in the global capital and credit markets in recent years have led to a significant reduction in the availability of business credit, decreased liquidity, a contraction of consumer credit, business failures, higher unemployment, and declines in consumer confidence and spending in the United States and internationally. If global economic and financial market conditions deteriorate or remain weak for an extended period of time, numerous economic and financial factors could have a material adverse effect on our business, operating results, and financial condition, including:

- decreased spending by electric power grid operators or utilities, or by end-users of electricity, may result in reduced demand for our energy management applications, services and products;
- consumer demand for electricity may be reduced, which could result in lower prices for both demand-side and supply-side capacity pursuant to utility contracts and in open market programs with electric power grid operators and utilities;
- if C&I customers in our demand response network experience financial difficulty, some may cease or reduce business operations, or reduce their electricity usage, all of which could reduce the number of MW of demand response capacity under our management;
- we may be unable to find suitable investments that are safe, liquid, and provide a reasonable return, which could result in lower interest income or longer investment horizons, and disruptions to capital markets or the banking system may also impair the value of investments or bank deposits we currently consider safe or liquid;
- if our C&I customers to whom we provide our EfficiencySMART or SupplySMART applications and services experience financial difficulty, it could result in their inability to timely meet their payment obligations to us, extended payment terms, higher accounts receivable, reduced cash flows, greater expense associated with collection efforts, and an increase in charges for uncollectable receivables; and
- due to stricter lending standards, C&I customers to whom we offer our SupplySMART application and services may be unable to obtain adequate credit ratings acceptable to electricity suppliers, resulting in increased costs, which might make our SupplySMART application and services less attractive or result in their inability to contract with us for SupplySMART.

Uncertainty about current global economic conditions could also continue to increase the volatility of our stock price.

Electric power industry sales cycles can be lengthy and unpredictable and require significant employee time and financial resources with no assurances that we will realize revenues.

Sales cycles with electric power grid operator and utility customers are generally long and unpredictable. The electric power grid operators and utilities that are our potential customers generally have extended budgeting, procurement and regulatory approval processes. They also tend to be risk averse and tend to follow industry trends rather than be the first to purchase new products or services, which can extend the lead time for or prevent acceptance of new products or services such as our energy management applications, services and products. Accordingly, our potential electric power grid operator and utility customers may take longer to reach a decision to purchase services. This extended sales process requires the dedication of significant time by our personnel and our use of significant financial resources, with no certainty of success or recovery of our related expenses. It is not unusual for an electric power grid operator or utility customer to go through the entire sales process and not accept any proposal or quote. Long and unpredictable sales cycles with electric power grid operator and utility customers could have a material adverse effect on our business, financial condition and results of operations.

We are exposed to potential risks and will continue to incur significant costs as a result of the internal control testing and evaluation process mandated by Section 404 of the Sarbanes-Oxley Act of 2002.

We assessed the effectiveness of our internal control over financial reporting as of December 31, 2012 and assessed all deficiencies on both an individual basis and in combination to determine if, when aggregated, they constitute a material weakness. As a result of this evaluation, no material weaknesses were identified.

We expect to continue to incur significant costs, including increased accounting fees and increased staffing levels, in order to maintain compliance with Section 404 of the Sarbanes-Oxley Act. We continue to monitor controls for any weaknesses or deficiencies. No evaluation can provide complete assurance that our internal controls will detect or uncover all failures of persons within the company to disclose material information otherwise required to be reported. The effectiveness of our controls and procedures could also be limited by simple errors or faulty judgments. In addition, as we continue to expand globally, the challenges involved in implementing appropriate internal controls will increase and will require that we continue to improve our internal controls over financial reporting.

In the future, if we fail to complete the Sarbanes-Oxley 404 evaluation in a timely manner, or if our independent registered public accounting firm cannot attest in a timely manner to our evaluation, we could be subject to regulatory scrutiny and a loss of public confidence in our internal controls, which could adversely impact the market price of our common stock. We or our independent registered public accounting firm may identify material weaknesses in internal controls over financial reporting, which also may result in a loss of public confidence in our internal controls and adversely impact the market price of our common stock. In addition, any failure to implement required, new or improved controls, or difficulties encountered in their implementation, could harm our operating results or cause us to fail to meet our reporting obligations.

Our ability to provide security deposits or letters of credit is limited and could negatively affect our ability to bid on or enter into utility contracts or arrangements with electric power grid operators and utilities.

We are increasingly required to provide security deposits in the form of cash to secure our performance under utility contracts and open market bidding programs with our electric power grid operator and utility customers. In addition, some of our electric power grid operator or utility customers require collateral in the form of letters of credit to secure our performance or to fund possible damages or penalty payments resulting from our failure to make available capacity at agreed upon levels or any other event of default by us. Our ability to obtain such letters of credit primarily depends upon our capitalization, working capital, past performance, management expertise and reputation and external factors beyond our control, including the overall capacity of the credit market. Events that affect credit markets generally may result in letters of credit becoming more difficult to obtain in the future, or being available only at a significantly greater cost. As of December 31, 2012, we had $42.6 million of letters of credit outstanding under the 2012 credit facility, leaving $7.4 million available under this facility for additional letters of credit. Furthermore, if it is determined that we are in default of our covenants under the 2012 credit facility, then any amounts outstanding under the 2012 credit facility would become immediately due and payable and we would be required to collateralize with cash any outstanding letters of credit up to 105% of the amounts outstanding.

We may be required, from time to time, to seek alternative sources of security deposits or letters of credit, which may be expensive and difficult to obtain, if available at all. Our inability to obtain letters of credit and, as a result, to bid or enter into utility contracts or arrangements with electric power grid operators or utilities, could have a material adverse effect on our future revenues and business prospects. In addition, in the event that we default under our utility contracts or open market bidding programs with our electric power grid operator and utility customers pursuant to which we have posted collateral, we may lose a portion or all of such collateral, which could have a material adverse effect on our financial condition and results of operations.

Our ability to use our net operating loss carryforwards may be subject to limitation.

Generally, a change of more than 50% in the ownership of a company's stock, by value, over a three-year period constitutes an ownership change for United States federal income tax purposes. An ownership change may limit a company's ability to use its net operating loss carryforwards attributable to the period prior to such change. The number of shares of our common stock that we issued in our initial public offering, or IPO, and follow-on public offerings, together with any subsequent shares of stock we issue, may be sufficient, taking into account prior or future shifts in our ownership over a three-year period, to cause us to undergo an ownership change. As a result, as we earn net taxable income, our ability to use our pre-ownership change net operating loss carryforwards to offset United States federal taxable income may become subject to limitations, which could potentially result in increased future tax liability for us. To date, although we have been able to utilize our net operating loss carryforwards to offset the maximum amount of taxable income allowed by the various tax jurisdictions in which we operate, we may not be able to utilize some or all of these net operating losses in the future.

If the software systems we use in providing our energy management applications, services and products or the manual implementation of such systems produce inaccurate information or is incompatible with the systems used by our customers, it could preclude us from providing our energy management applications, services and products, which could lead to a loss of revenues and trigger penalty payments.

Our software is complex and, accordingly, may contain undetected errors or failures when introduced or subsequently modified. Software defects or inaccurate data may cause incorrect recording, reporting or display of information about the level of demand reduction at a C&I customer site, which could cause us to fail to meet our commitments to have capacity available or could result in an overpayment or underpayment to us and our C&I customers by our electric power grid operator and utility customers. Any such failures could also cause us to be subject to penalty payments to our electric power grid operator and utility customers, cause a reduction in our revenue in the period that any adjustment is identified and result in reductions in capacity payments under utility contracts and open market bidding programs in subsequent periods. In addition, such defects and inaccurate data may prevent us from successfully providing our portfolio of additional energy management applications, services and products, which would result in lost revenues. Software defects or inaccurate data may lead to customer dissatisfaction and our customers may seek to hold us liable for any damages incurred. As a result, we could lose customers, our reputation could be harmed and our financial condition and results of operations could be materially adversely affected.

We currently serve a C&I customer base that uses a wide variety of constantly changing hardware, software applications and operating systems. Building control, process control and metering systems frequently reside on non-standard operating systems. Our energy management applications, services and products need to interface with these non-standard systems in order to gather and assess data and to implement changes in electricity consumption. Our business depends on the following factors, among others:

- our ability to integrate our technology with new and existing hardware and software systems, including metering, building control, process control, and distributed generation systems;
- our ability to anticipate and support new standards, especially Internet-based standards and building control and metering system protocol languages; and
- our ability to integrate additional software modules under development with our existing technology and operational processes.

If we are unable to adequately address any of these factors, our results of operations and prospects for growth could be materially adversely effected.

We may face certain product liability or warranty claims if we disrupt our customers' networks or applications.

For some of our current and planned applications, our software and hardware is integrated with our C&I customers' networks and software applications. The integration of our software and hardware may entail the risk of product liability or warranty claims based on disruption or security breaches to these networks or applications. In addition, the failure of our software and hardware to perform to customer expectations could give rise to warranty claims against us. Any of these claims, even if without merit, could result in costly litigation or divert management's attention and resources. Although we carry general liability insurance, our current insurance coverage could be insufficient to protect us from all liability that may be imposed under these types of claims. A material product liability claim may seriously harm our results of operations.

Fluctuations in the exchange rates of foreign currencies in which we conduct our business, in relation to the U.S. dollar, could harm our business and prospects.

We maintain sales and service offices outside the United States. The expenses of our international offices are denominated in local currencies. In addition, our foreign sales may be denominated in local currencies. Fluctuations in foreign currency exchange rates could affect our revenues, cost of revenues and profit margins and could result in exchange losses. In addition, currency devaluation can result in a loss if we hold deposits of that currency. In the last few years we have not hedged foreign currency exposures, but we may in the future hedge foreign currency denominated sales. There is a risk that any hedging activities will not be successful in mitigating our foreign exchange risk exposure and may adversely impact our financial condition and results of operations.

An adverse change in the projected cash flows from our acquired businesses or the business climate in which they operate, including the continuation of the current financial and economic turmoil, could require us to incur an impairment charge, which would have an adverse impact on our operating results.

We periodically review the carrying value of the goodwill and other long-lived assets reflected in our financial statements to determine if any adverse conditions exist or a change in circumstances has occurred that would indicate impairment of the value of these assets. Conditions that would indicate impairment and necessitate a revaluation of these assets include, but are not limited to, a significant adverse change in the business climate or the legal or regulatory environment within which we operate. If the carrying value of an asset is determined to be impaired we will write-down the carrying value of the intangible asset to its fair value in the period identified. We generally calculate fair value as the present value of estimated future cash flows to be generated by the asset using a risk-adjusted discount rate. As of December 31, 2012, we had approximately $105.1 million of goodwill and definite-lived intangible assets. As of November 30, 2012, which is our annual impairment test date, the fair value of our reporting units exceeded the book value of their corresponding net assets and as such, there was no indication of a goodwill impairment. In addition, as of December 31, 2012, we had no indefinite-lived intangible assets. Our market capitalization was greater than the book value of our net assets as of December 31, 2012. However, we have experienced significant volatility in the price of our publicly-traded common stock and related market capitalization over the past twelve months, including a decline in a market capitalization slightly below the book value of our net assets. We will continue to monitor our market capitalization compared to the book value of our net assets. It is possible that the continuation of the current global financial and economic turmoil could negatively affect our anticipated cash flows, or the discount rate that is applied to valuing those cash flows, which could require an interim impairment test of goodwill. Any impairment test could result in a material impairment charge that would have an adverse impact on our financial condition and results of operations.

Risks Related to Our Common Stock

We expect our quarterly revenues and operating results to fluctuate. If we fail in future periods to meet our publicly announced financial guidance or the expectations of market analysts or investors, the market price of our common stock could decline substantially.

Our quarterly revenues and operating results have fluctuated in the past and may vary from quarter to quarter in the future. Accordingly, we believe that period-to-period comparisons of our results of operations may be misleading. The results of one quarter should not be used as an indication of future performance. We provide public guidance on our expected results of operations for future periods. This guidance is comprised of forward-looking statements subject to risks and uncertainties, including the risks and uncertainties described in this Annual Report on Form 10-K for the fiscal year ended December 31, 2012 and in our other public filings and public statements, and is based necessarily on assumptions we make at the time we provide such guidance. Our revenues and operating results may fail to meet our previously stated financial guidance or the expectations of securities analysts or investors in some quarter or quarters. Our failure to meet such expectations or our financial guidance could cause the market price of our common stock to decline substantially.

Our quarterly revenues and operating results may vary depending on a number of factors, including:

- demand for and acceptance of our energy management applications, services and products;
- the seasonality of our demand response business in certain of the markets in which we operate, where revenues recognized under certain utility contracts and pursuant to certain open market bidding programs can be higher or concentrated in particular seasons and months;
- changes in open market bidding program rules and reductions in pricing for demand response capacity;
- delays in the implementation and delivery of our energy management applications, services and products, which may impact the timing of our recognition of revenues;
- delays or reductions in spending for energy management applications, services and products by our electric power grid operator or utility customers and potential customers;
- the long lead time associated with securing new customer contracts;
- the structure of any forward capacity market in which we participate, which may impact the timing of our recognition of revenues related to that market;
- the mix of our revenues during any period, particularly on a regional basis, since local fees recognized as revenues for demand response capacity tend to vary according to the level of available capacity in given regions;
- the termination or expiration of existing contracts with electric power grid operator, utility and C&I customers;
- the potential interruptions of our customers' operations;
- development of new relationships and maintenance and enhancement of existing relationships with customers and strategic partners;
- temporary capacity programs that could be implemented by electric power grid operators and utilities to address short-term capacity deficiencies;
- the imposition of penalties or the reversal of deferred revenue due to our failure to meet a capacity commitment;
- the elimination, modification or flawed design of, or our decision not to participate or to reduce our participation in, any demand response program in which we currently participate;
- global economic and credit market conditions; and
- increased expenditures for sales and marketing, software development and other corporate activities.

Our stock price has been and is likely to continue to be volatile and the market price of our common stock may fluctuate substantially.

Prior to our IPO in May 2007, there was not a public market for our common stock. There is a limited history on which to gauge the volatility of our stock price; however, since our common stock began trading on The NASDAQ Global Market, or NASDAQ, on May 18, 2007 through December 31, 2012, our stock price has fluctuated from a low of \$4.80 to a high of \$50.50. During the year ended December 31, 2012, our stock price fluctuated from a low of \$5.41 to a high of \$14.51. Furthermore, the stock market has continued to experience significant volatility. The volatility of stocks for companies in the energy and technology industry often does not relate to the operating performance of the companies represented by the stock. Some of the factors that may cause the market price of our common stock to fluctuate include:

- demand for and acceptance of our energy management applications, services and products;
- our ability to develop new relationships and maintain and enhance existing relationships with customers and strategic partners;
- changes in open market bidding program rules and reductions in pricing for demand response capacity;
- the termination or expiration of existing contracts with electric power grid operator, utility and C&I customers;
- general market conditions and overall fluctuations in equity markets in the United States;
- the elimination, modification or flawed design of, or our decision not to participate or to reduce our participation in, any demand response program in which we currently participate;
- introduction of technological innovations or new energy management applications, services or products by us or our competitors;
- actual or anticipated variations in quarterly revenues and operating results;
- the financial guidance we may provide to the public, any changes in such guidance or our failure to meet such guidance;
- changes in estimates or recommendations by securities analysts that cover our common stock;
- delays in the implementation and delivery of our energy management applications, services and products, which may impact the timing of our recognition of revenues;
- litigation or regulatory enforcement actions;
- changes in the regulations affecting our industry in the United States and internationally;
- the way in which we recognize revenues and the timing associated with our recognition of revenues;
- developments or disputes concerning patents or other proprietary rights;
- period-to-period fluctuations in our financial results;
- the potential interruptions of our customers' operations;
- the seasonality of our demand response business in certain of the markets in which we operate;
- failure to secure adequate capital to fund our operations, or the future sale or issuance of securities at prices below fair market price or in general; and
- economic and other external factors or other disasters or crises.

These and other external factors may cause the market price and demand for our common stock to fluctuate substantially, which may limit or prevent investors from readily selling their shares of common stock and may otherwise negatively affect the liquidity of our common stock. In addition, in the past, when the market price of a stock has been volatile, holders of that stock have instituted securities class action litigation against the company that issued the stock. Our stock price has been particularly volatile recently and may continue to be volatile in the near term and we could incur substantial costs defending any lawsuit brought against us by any of our stockholders. Such a lawsuit could also divert the time and attention of our management.

We do not intend to pay dividends on our common stock.

We have not declared or paid any cash dividends on our common stock to date, and we do not anticipate paying any dividends on our common stock in the foreseeable future. We currently intend to retain all available funds and any future earnings for use in the development, operation and growth of our business. In addition, the 2012 credit facility prohibits us from paying dividends and future loan agreements may also prohibit the payment of dividends. Any future determination relating to our dividend policy will be at the discretion of our board of directors and will depend on our results of operations, financial condition, capital requirements, business opportunities, contractual restrictions and other factors deemed relevant. To the extent we do not pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in our common stock.

Provisions of our certificate of incorporation, bylaws and Delaware law, and of some of our employment arrangements, may make an acquisition of us or a change in our management more difficult and could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Certain provisions of our certificate of incorporation and bylaws could discourage, delay or prevent a merger, acquisition or other change of control that stockholders may consider favorable, including transactions in which we may have otherwise received a premium on our shares of common stock. These provisions also could limit the price that investors might be willing to pay in the future for shares of our common stock, thereby depressing the market price of our common stock. Stockholders who wish to participate in these transactions may not have the opportunity to do so. Furthermore, these provisions could prevent or frustrate attempts by our stockholders to replace or remove our management. These provisions:

- allow the authorized number of directors to be changed only by resolution of our board of directors;
- require that vacancies on the board of directors, including newly created directorships, be filled only by a majority vote of directors then in office;
- establish a classified board of directors, providing that not all members of the board be elected at one time;
- authorize our board of directors to issue, without stockholder approval, blank check preferred stock that, if issued, could operate as a "poison pill" to dilute the stock ownership of a potential hostile acquirer to prevent an acquisition that is not approved by our board of directors;
- require that stockholder actions must be effected at a duly called stockholder meeting and prohibit stockholder action by written consent;
- prohibit cumulative voting in the election of directors, which would otherwise allow holders of less than a majority of stock to elect some directors;
- establish advance notice requirements for stockholder nominations to our board of directors or for stockholder proposals that can be acted on at stockholder meetings;
- limit who may call stockholder meetings; and
- require the approval of the holders of 75% of the outstanding shares of our capital stock entitled to vote in order to amend certain provisions of our certificate of incorporation and bylaws.

Some of our employment arrangements and equity agreements provide for severance payments and accelerated vesting of benefits, including accelerated vesting of equity awards, upon a change of control. These provisions may discourage or prevent a change of control. In addition, because we are incorporated in Delaware, we are governed by the provisions of Section 203 of the Delaware General Corporation Law, which may, unless certain criteria are met, prohibit large stockholders, in particular those owning 15% or more of our outstanding voting stock, from merging or combining with us for a proscribed period of time.

If securities or industry analysts do not publish research or publish inaccurate or unfavorable research about our business, our stock price and trading volume could decline.

The trading market for our common stock will continue to depend in part on the research and reports that securities or industry analysts publish about us or our business. If these analysts do not continue to provide adequate research coverage or if one or more of the analysts who covers us downgrades our stock or publishes inaccurate or unfavorable research about our business, our stock price would likely decline. If one or more of these analysts ceases coverage of our company or fails to publish reports on us regularly, demand for our stock could decrease, which could cause our stock price and trading volume to decline.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and The NASDAQ Stock Market LLC, require significant resources, increase our costs and distract our management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with equity securities listed on NASDAQ, we must comply with statutes and regulations of the SEC and the requirements of NASDAQ. Complying with these statutes, regulations and requirements occupies a significant amount of the time of our board of directors and management and significantly increases our costs and expenses. In addition, as a public company we incur substantial costs to obtain director and officer liability insurance policies. These factors could make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our audit committee.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Our corporate headquarters are located in Boston, Massachusetts, where we lease approximately 61,032 square feet under a lease agreement expiring in June 2013. Prior to the expiration of our lease agreement in June 2013, we expect to move our corporate headquarters to a new facility located at One Marina Park Drive, Floors 4-6, Boston, Massachusetts pursuant to a new lease, under which we have agreed to lease approximately 82,000 square feet of office space and which expires on July 31, 2020.

We also lease a number of offices under various other lease agreements in the United States, Australia, Canada, New Zealand and the United Kingdom. We do not own any real property. We believe that our leased facilities will be adequate to meet our needs for the foreseeable future.

Item 3. Legal Proceedings

We are subject to legal proceedings, claims and litigation arising in the ordinary course of business. We do not expect the ultimate costs to resolve these matters to have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Price Range of Our Common Stock

Our common stock is currently traded on The NASDAQ Global Market under the symbol "ENOC". The following table sets forth the high and low sales prices per share of our common stock as reported on The NASDAQ Global Market for the periods indicated.

Year ended December 31, 2012	High	Low
First Quarter	$11.75	$ 7.11
Second Quarter	$ 7.94	$ 5.41
Third Quarter	$13.40	$ 6.04
Fourth Quarter	$14.51	$10.69
Year ended December 31, 2011	**High**	**Low**
First Quarter	$26.57	$16.63
Second Quarter	$22.38	$15.30
Third Quarter	$17.72	$ 8.39
Fourth Quarter	$12.24	$ 8.00

Stockholders

As of February 25, 2013, we had approximately 734 stockholders of record. This number does not include stockholders for whom shares are held in a "nominee" or "street" name.

Dividend Policy

We have never paid or declared any cash dividends on our common stock. We currently intend to retain all available funds and any future earnings to fund the development and expansion of our business, and we do not anticipate paying any cash dividends in the foreseeable future. Any future determination to pay dividends will be at the discretion of our board of directors and will depend on our financial condition, results of operations, capital requirements, and other factors that our board of directors deems relevant. Additionally, the terms of the 2012 credit facility preclude us, and the terms of any future debt or credit facility may preclude us, from paying dividends.

Unregistered Sales of Equity Securities

None.

Issuer Purchases of Equity Securities

None.

Item 6. Selected Financial Data

Our selected consolidated financial data set forth below is derived from our audited financial statements, of which the financial statements as of December 31, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010 are contained elsewhere in this Annual Report on Form 10-K. The following selected consolidated financial data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and accompanying notes thereto included in Item 7 and Appendix A, respectively, to this Annual Report on Form 10-K.

	Year Ended December 31,				
	2012	2011(1)	2010(1)	2009(1)	2008(1)
	(In thousands, except share and per share data)				
Selected Balance Sheet Data:					
Cash and cash equivalents	$ 115,041	$ 87,297	$ 153,416	$ 119,739	$ 60,782
Marketable securities	—	—	—	—	2,000
Working capital	116,685	105,839	163,519	124,680	59,137
Total assets	363,207	355,260(2)	325,899	255,022	136,694
Total long-term debt, including current portion	—	—	37	73	4,563
Total stockholders' equity	240,022	247,740	226,126	194,975	99,220
Selected Statement of Operations Data:					
Revenues	$ 277,984	$ 286,608	$ 280,157	$ 190,675	$ 106,115
Cost of revenues	154,540	163,211	159,832	104,215	64,819
Gross profit	123,444	123,397	120,325	86,460	41,296
Selling and marketing expenses	55,963	51,907	44,029(3)	39,502	30,789
General and administrative expenses	71,643	66,773	54,983(3)	44,407	41,582
Research and development expenses	16,226	14,254	10,097	7,601	6,123
(Loss) income from operations	(20,388)	(9,537)	11,216	(5,050)	(37,198)
Interest and other (expense) income, net	(134)	(2,040)	(803)	(1,446)	798
(Loss) income before income taxes	(20,522)	(11,577)	10,413	(6,496)	(36,400)
Provision for income taxes	(1,771)	(1,806)	(836)	(333)	(262)
Net (loss) income	$ (22,293)	$ (13,383)	$ 9,577	$ (6,829)	$ (36,662)
Net (loss) income per share, basic	$ (0.84)	$ (0.52)	$ 0.39	$ (0.32)	$ (1.88)
Net (loss) income per share, diluted	$ (0.84)	$ (0.52)	$ 0.37	$ (0.32)	$ (1.88)
Weighted average number of basic shares	26,551,234	25,799,494	24,611,729	21,466,813	19,505,065
Weighted average number of diluted shares	26,551,234	25,799,494	26,054,162	21,466,813	19,505,065

(1) Includes the results of operations from the date of acquisition relating to our acquisitions of Energy Response Holdings Pty Ltd, or Energy Response, in July 2011; Global Energy Partners, Inc., or Global Energy, M2M and an immaterial acquisition in January 2011; SmallFoot LLC, or SmallFoot, and ZOX, LLC, or Zox, in March 2010; Cogent Energy, Inc., or Cogent, in December 2009; eQuilibrium Solutions Corporation, or eQ, in June 2009; and South River Consulting, or SRC, in May 2008. See Note 2 of our accompanying consolidated financial statements contained in Appendix A to this Annual Report on Form 10-K for a discussion of the acquisitions that occurred during 2010, 2011 and 2012.

(2) We have reclassified certain amounts in our consolidated balance sheet as of December 31, 2011 resulting in a decrease to both accounts receivable and deferred revenues of $2,012 to properly account for outstanding accounts receivable for fees that had been deferred because they were not fixed or determinable. We have also reclassified certain amounts in our consolidated balance sheet as of December 31, 2011 resulting in an increase to both accounts receivable and accounts payable of $1,464 to properly account for receivables and payables under a contractual arrangement on a gross basis.

(3) We have reclassified certain costs in our consolidated statements of operations for the year ended December 31, 2010 totaling $1,407 from selling and marketing expenses to general and administrative expenses to more appropriately reflect the nature of these costs consistent with costs in the year ended December 31, 2011. These costs commenced in the year ended December 31, 2010 and therefore no reclassification was required for any periods prior to 2010.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

You should read the following discussion and analysis of our financial condition and results of operations together with our "Selected Financial Data" and consolidated financial statements and accompanying notes thereto included elsewhere in this Annual Report on Form 10-K. In addition to the historical information, the discussion contains certain forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those expressed or implied by the forward-looking statements due to applications of our critical accounting policies and factors including, but not limited to, those set forth under the caption "Risk Factors" in Item 1A of Part I of this Annual Report on Form 10-K.

Overview

We are a leading provider of energy management applications, services and products for the smart grid, which include comprehensive demand response, data-driven energy efficiency and energy price and risk management applications, services and products. Our energy management applications, services and products enable cost effective energy management strategies for our C&I, electric power grid operator and utility customers by reducing real-time demand for electricity, increasing energy efficiency and improving energy supply transparency.

We believe that we are the world's leading provider of demand response applications and services. Demand response is an alternative to traditional power generation and transmission infrastructure projects that enables electric power grid operators and utilities to reduce the likelihood of service disruptions, such as brownouts and blackouts, during periods of peak electricity demand, and otherwise manage the electric power grid during short-term imbalances of supply and demand or during periods when energy prices are high.

We build on our position as a leading demand response services provider by using our NOC and energy management application platform to deliver a portfolio of additional energy management applications, services and products to new and existing C&I, electric power grid operator and utility customers. These additional energy management applications, services and products include our EfficiencySMART and SupplySMART applications and services, and certain wireless energy management products. EfficiencySMART is our data-driven energy efficiency suite that includes energy efficiency planning, audits, assessments, commissioning and retro-commissioning authority services, and a cloud-based energy analytics application used for managing energy across a C&I customer's portfolio of sites. The cloud-based energy analytics application also includes the ability to integrate with a C&I customer's existing energy management system, provide utility bill management and tools for measurement, tracking, analysis, reporting and management of greenhouse gas emissions. SupplySMART is our energy price and risk management application that provides our C&I customers located in restructured or deregulated markets throughout the United States with the ability to more effectively manage the energy supplier selection process, including energy supply product procurement and implementation, budget forecasting, and utility bill management. Our wireless energy management products are designed to ensure that our C&I customers can connect their equipment remotely and access meter data securely, and include both cellular modems and an agricultural specific wireless technology solution acquired as part of our acquisition of M2M in January 2011.

Since inception, our business has grown substantially. We began by providing demand response services in one state in 2003 and have expanded to providing our portfolio of energy management applications, services and products in several regions throughout the United States, as well as internationally in Australia, Canada, New Zealand and the United Kingdom.

Revenues and Expense Components

Revenues

We derive recurring revenues from the sale of our energy management applications, services and products. We do not recognize any revenues until persuasive evidence of an arrangement exists, delivery has occurred, the fee is fixed or determinable, and we deem collection to be reasonably assured.

Our revenues from our demand response services primarily consist of capacity and energy payments, including ancillary services payments, and revenues derived from the effective management of our portfolio of demand response capacity, including our participation in capacity auctions and bilateral contracts. We derive revenues from demand response capacity that we make available in open market programs and pursuant to contracts that we enter into with electric power grid operators and utilities. In certain markets, we enter into contracts with electric power grid operators and utilities, generally ranging from three to ten years in duration, to deploy our demand response services. We refer to these contracts as utility contracts.

Where we operate in open market programs, our revenues from demand response capacity payments may vary month-to-month based upon our enrolled capacity and the market payment rate. Where we have a utility contract, we receive periodic capacity payments, which may vary monthly or seasonally, based upon enrolled capacity and predetermined payment rates. Under both open market programs and utility contracts, we receive capacity payments regardless of whether we are called upon to reduce demand for electricity from the electric power grid; and we recognize revenue over the applicable delivery period, even when payments are made over a different period. We generally demonstrate our capacity either through a demand response event or a measurement and verification test. This demonstrated capacity is typically used to calculate the continuing periodic capacity payments to be made to us until the next demand response event or measurement and verification test establishes a new demonstrated capacity amount. In most cases, we also receive an additional payment for the amount of energy usage that we actually curtail from the grid during a demand response event. We refer to this as an energy payment.

As program rules may differ for each open market program in which we participate and for each utility contract, we assess whether or not we have met the specific service requirements under the program rules and recognize or defer revenues as necessary. We recognize demand response capacity revenues when we have provided verification to the electric power grid operator or utility of our ability to deliver the committed capacity under the open market program or utility contract. Committed capacity is verified through the results of an actual demand response event or a measurement and verification test. Once the capacity amount has been verified, the revenues are recognized and future revenues become fixed or determinable and are recognized monthly over the performance period until the next demand response event or measurement and verification test. In subsequent demand response events or measurement and verification tests, if our verified capacity is below the previously verified amount, the electric power grid operator or utility customer will reduce future payments based on the adjusted verified capacity amounts. Under certain utility contracts and open market program participation rules, our performance and related fees are measured and determined over a period of time. If we can reliably estimate our performance for the applicable performance period, we will reserve the entire amount of estimated penalties that will be incurred, if any, as a result of estimated underperformance prior to the commencement of revenue recognition. If we are unable to reliably estimate the performance and any related penalties, we defer the recognition of revenues until the fee is fixed or determinable. Any changes to our original estimates of net revenues are recognized as a change in accounting estimate in the earliest reporting period that such a change is determined.

As of December 31, 2012, we had over 8,600 MW in our demand response network, meaning that we had entered into definitive contracts with our C&I customers representing over 8,600 MW of demand response capacity. In determining our MW in the seasonal demand response programs in which we participate, we typically count the maximum determinable amount of curtailable load for a C&I customer site over a trailing twelve-month period as the MW for that C&I customer site. However, the trailing period could be longer in certain programs under which significant rule changes have occurred or under which we do not have enough obligation to enroll all of our MW in a given program period, but have enough obligation in a future program period to enroll those MW. We generally begin earning revenues from our MW within approximately one to three months from the date on which we enable the MW, or the date on which we can reduce the MW from the electric power grid if called upon to do so. The most significant exception is the PJM forward capacity market, which is a market from which we derive a substantial portion of our revenues. Because PJM operates on a June to May program-year basis, the revenues associated with a MW that we enable after June of each year will typically not be recognized until September of the following year. Certain other markets in which we currently participate, such as the Western Australia market and ISO-NE market, or may choose to participate in the future, operate or may operate in a manner that could create a delay in recognizing revenue from the MW that we enable in those markets.

In the PJM open market program in which we participate, the program year operates on a June to May basis and performance is measured based on the aggregate performance during the months of June through September. As a result, fees received for the month of June could potentially be subject to adjustment or refund based on performance during the months of July through September. Based on changes to certain PJM program rules during the year ended December 31, 2012, or fiscal 2012, we concluded that we no longer had the ability to reliably estimate the amount of fees potentially subject to adjustment or refund until the performance period ends on September 30th of each year. Therefore, commencing in fiscal 2012, all demand response capacity revenues related to our participation in the PJM open market program are being recognized at the end of the performance period, or during the three months ended September 30th of each year. As a result of the fact that the period during which we are required to perform (June through September) is shorter than the period over which we receive payments under the program (June through May), a portion of the revenues that have been earned will be recorded and accrued as unbilled revenue.

Our revenues have historically been higher in the second and third quarters of our fiscal year due to seasonality related to the demand response market. We expect, based on the fact that we recognize demand response capacity revenue related to our participation in the PJM open market program during the three months ended September 30th of each year, that our revenues will typically be higher in the third quarter as compared to any other quarter in our fiscal year.

Revenues generated from open market sales to PJM accounted for 40%, 53% and 60% respectively, of our total revenues for the years ended December 31, 2012, 2011 and 2010. Under certain utility contracts and open market programs, such as PJM's Emergency Load Response Program, the period during which we are required to perform may be shorter than the period over which we receive payments under that contract or program. In these cases, we record revenue, net of reserves for estimated penalties related to potential delivered capacity shortfalls, over the mandatory performance obligation period, and a portion of the revenues that have been earned is recorded and accrued as unbilled revenue. Our unbilled revenue of $44.9 million from PJM as of December 31, 2012 will be billed and collected through June 2013. Our unbilled revenue of $64.1 million as of December 31, 2011 was collected through June 2012.

Revenues generated from open market sales to ISO-NE accounted for 8%, 13% and 18%, respectively, of our total revenues for the years ended December 31, 2012, 2011 and 2010. Other than PJM and ISO-NE, no individual electric power grid operator or utility customers accounted for more than 10% of our total revenues for the years ended December 31, 2012, 2011 and 2010. If we choose to participate in additional or different markets in the future, the contribution of our current electric power grid operator and utility customers to total revenues will change.

With respect to our EfficiencySMART and SupplySMART applications and services, these applications and services generally represent ongoing service arrangements where the revenues are recognized ratably over the service period commencing upon delivery of the contracted service to the customer. Under certain of our arrangements, in particular certain EfficiencySMART arrangements with our utility customers, a portion of the fees received may be subject to adjustment or refund based on the validation of the energy savings delivered after the implementation is complete. As a result, we defer the portion of the fees that are subject to adjustment or refund until such time as the right of adjustment or refund lapses, which is generally upon completion and validation of the implementation. In addition, under certain of our other arrangements, in particular those arrangements entered into by our wholly-owned subsidiary, M2M, we sell proprietary equipment to C&I

customers that is utilized to provide the ongoing services that we deliver. Currently, this equipment has been determined to not have stand-alone value. As a result, we defer the fees associated with the equipment and begin recognizing those fees ratably over the expected C&I customer relationship period, which is generally 3 years, once the C&I customer is receiving the ongoing services from us. In addition, we capitalize the associated direct and incremental costs, which primarily represent the equipment and third-party installation costs, and recognize such costs over the expected C&I customer relationship period.

Revenues derived from EfficiencySMART and SupplySMART applications and services, and certain other wireless energy management products were $33.1 million, $27.5 million and $15.5 million, respectively, for the years ended December 31, 2012, 2011 and 2010.

Cost of Revenues

Cost of revenues for our demand response services primarily consists of amounts owed to our C&I customers for their participation in our demand response network and are generally recognized over the same performance period as the corresponding revenue. We enter into contracts with our C&I customers under which we deliver recurring cash payments to them for the capacity they commit to make available on demand. We also generally make an energy payment when a C&I customer reduces consumption of energy from the electric power grid during a demand response event. The equipment and installation costs for our devices located at our C&I customer sites, which monitor energy usage, communicate with C&I customer sites and, in certain instances, remotely control energy usage to achieve committed capacity are capitalized and depreciated over the lesser of the remaining estimated customer relationship period or the estimated useful life of the equipment, and this depreciation is reflected in cost of revenues. We also include in cost of revenues our amortization of acquired developed technology, amortization of capitalized internal-use software costs related to our DemandSMART application, the monthly telecommunications and data costs we incur as a result of being connected to C&I customer sites, and our internal payroll and related costs allocated to a C&I customer site. Certain costs, such as equipment depreciation and telecommunications and data costs, are fixed and do not vary based on revenues recognized. These fixed costs could impact our gross margin trends described elsewhere in this Annual Report on Form 10-K during interim periods. Cost of revenues for our EfficiencySMART and SupplySMART applications and services, and certain other wireless energy management products includes our amortization of capitalized internal-use software costs related to those applications, services and products, third-party services, equipment costs, equipment depreciation, and the wages and associated benefits that we pay to our project managers for the performance of their services.

We defer incremental direct costs incurred related to the acquisition or origination of a utility contract or open market program in a transaction that results in the deferral or delay of revenue recognition. As of December 31, 2012 and 2011, we had no incremental direct costs deferred related to the acquisition or origination of a utility contract or open market program and during the years ended December 31, 2012, 2011 and 2010, no contract origination costs were deferred. During the year ended December 31, 2011, as a result of the termination of a certain contract, $0.9 million of previously deferred incremental direct costs were expensed. In addition, we defer incremental direct costs incurred related to customer contracts where the associated revenues have been deferred as long as the deferred incremental direct costs are deemed realizable. During the years ended December 31, 2012, 2011 and 2010, we deferred $17.7 million, $8.1 million and $3.9 million, respectively, of incremental direct costs associated with customer contracts. These deferred expenses would not have been incurred without our participation in a certain open market program and will be expensed in proportion to the related revenue being recognized. During the years ended December 31, 2012, 2011 and 2010, we expensed $10.8 million, $1.0 million and $4.9 million, respectively, of deferred incremental direct costs to cost of revenues. As of December 31, 2012, there had been no material realizability issues related to deferred incremental direct costs. We also capitalize the costs of our production and generation equipment utilized in the delivery of our demand response services and expense this equipment over the lesser of its estimated useful life or the term of the contractual arrangement. During the years ended December 31, 2012, 2011 and 2010, we capitalized $7.0 million, $9.5 million and $8.9 million, respectively, of production and generation equipment costs. We believe that the above accounting treatments appropriately match expenses with the associated revenue.

Gross Profit and Gross Margin

Gross profit consists of our total revenues less our cost of revenues. Our gross profit has been, and will be, affected by many factors, including (a) the demand for our energy management applications, services and products, (b) the selling price of our energy management applications, services and products, (c) our cost of revenues, (d) the way in which we manage, or are permitted to manage by the relevant electric power grid operator or utility, our portfolio of demand response capacity, (e) the introduction of new energy management applications, services and products, (f) our demand response event performance and (g) our ability to open and enter new markets and regions and expand deeper into markets we already serve. The effective management of our portfolio of demand response capacity, including our outcomes in negotiating favorable contracts with our customers and our participation in capacity auctions and bilateral contracts, and our demand response event performance, are the primary determinants of our gross profit and gross margin.

Operating Expenses

Operating expenses consist of selling and marketing, general and administrative, and research and development expenses. Personnel-related costs are the most significant component of each of these expense categories. We grew from 599 full-time employees at December 31, 2011 to 685 full-time employees at December 31, 2012 primarily as a result of our overall growth and expansion into new markets during this period. We expect to continue to hire employees to support our growth for the foreseeable future. In addition, we incur significant up-front costs associated with the expansion of the number of MW under our management, which we expect to continue for the foreseeable future. We expect our overall operating expenses to increase in absolute dollar terms for the foreseeable future as we continue to enable new C&I customer sites, further increase our headcount and expand the development of our energy management applications, services and products. In addition, amortization expense from intangible assets acquired in possible future acquisitions could potentially increase our operating expenses in future periods. Although we expect an increase in operating expenses in absolute dollar terms for the foreseeable future, we expect that operating expenses as a percentage of revenues will decrease as we continue to realize improvements in our operating leverage and overall cost management.

Selling and Marketing

Selling and marketing expenses consist primarily of (a) salaries and related personnel costs, including costs associated with share-based payment awards, related to our sales and marketing organization, (b) commissions, (c) travel, lodging and other out-of-pocket expenses, (d) marketing programs such as trade shows and (e) other related overhead. Commissions are recorded as an expense when earned by the employee. We expect an increase in selling and marketing expenses in absolute dollar terms for the foreseeable future as we further increase the number of sales professionals and, to a lesser extent, increase our marketing activities; however, we expect that selling and marketing expenses as a percentage of revenues will decrease for the foreseeable future.

General and Administrative

General and administrative expenses consist primarily of (a) salaries and related personnel costs, including costs associated with share-based payment awards and bonuses, related to our executive, finance, human resource, information technology and operations organizations, (b) facilities expenses, (c) accounting and legal professional fees, (d) depreciation and amortization and (e) other related overhead. We expect general and administrative expenses to continue to increase in absolute dollar terms for the foreseeable future as we invest in infrastructure to support our continued growth; however, we expect that general and administrative expenses as a percentage of revenues will decrease for the foreseeable future.

Research and Development

Research and development expenses consist primarily of (a) salaries and related personnel costs, including costs associated with share-based payment awards, related to our research and development organization, (b) payments to suppliers for design and consulting services, (c) costs relating to the design and development of new energy management applications, services and products and enhancement of existing energy management applications, services and products, (d) quality assurance and testing and (e) other related overhead. During the years ended December 31, 2012, 2011 and 2010, we capitalized software development costs of $4.7 million, $3.2 million and $6.8 million, respectively, which are included as software in property and equipment at December 31, 2012. We expect research and development expenses to increase in absolute dollar terms for the foreseeable future as we develop new technologies and enhance our existing technologies; however, we expect that research and development expenses as a percentage of revenues will decrease for the foreseeable future.

Stock-Based Compensation

We account for stock-based compensation in accordance with Accounting Standards Codification, or ASC 718, *Stock Compensation*. As such, all share-based payments to employees, including grants of stock options, restricted stock and restricted stock units, are recognized in the statement of operations based on their fair values as of the date of grant. During the year ended December 31, 2012, in lieu of a portion of cash bonuses related to our 2012 and 2013 bonus plans, we granted 1,023,010 shares of non-vested restricted stock to certain executives and non-executive employees that contain performance-based vesting conditions. These awards will vest in equal installments in 2013 and 2014 if the performance conditions are achieved. If the employee who received the restricted stock leaves the company for any reason prior to the vesting date, the shares of restricted stock will be forfeited and returned to us. In addition, in December 2011, we granted 283,334 shares of non-vested restricted stock to certain non-executive employees that contained performance-based vesting conditions in lieu of a portion of cash bonuses related to our 2012 and 2013 bonus plan. The performance conditions associated with the December 2011 grants were modified during the three months ended March 31, 2012. As a result of these grants of non-vested restricted stock, we anticipate that, on a per employee basis, stock-based compensation expense will increase for the foreseeable future with a corresponding decrease in cash compensation expense.

For the years ended December 31, 2012, 2011 and 2010, we recorded expenses of approximately $13.6 million, $13.5 million and $15.7 million, respectively, in connection with share-based payment awards to employees and non-employees. With respect to option grants through December 31, 2012, a future expense of non-vested options of approximately $1.7 million is expected to be recognized over a weighted average period of 1.3 years. For non-vested restricted stock awards and restricted stock units subject to service-based vesting conditions outstanding as of December 31, 2012, we had $8.4 million of unrecognized stock-based compensation expense, which is expected to be recognized over a weighted average period of 2.5 years. For non-vested restricted stock awards subject to performance-based vesting conditions outstanding, and that were probable of vesting as of December 31, 2012, we had $3.9 million of unrecognized stock-based compensation expense, which is expected to be recognized over a weighted average period of 1.3 years. For non-vested restricted stock awards subject to outstanding performance-based vesting conditions that were not probable of vesting as of December 31, 2012, we had $0.7 million of unrecognized stock-based compensation expense. If and when any additional portion of our outstanding equity awards is deemed probable to vest or awards that are deemed probable to vest become not probable, we will reflect the effect of the change in estimate in the period of change by recording a cumulative catch-up adjustment to retroactively apply the new estimate.

Although the number of share-based awards has increased significantly during the year ended December 31, 2012 as compared to the same period in 2011 due to stock-based compensation being issued in lieu of certain cash compensation, the overall amount of our stock-based compensation expense has decreased as a result of the lower fair value of these awards compared to awards granted in prior periods due to our lower stock price compared to the same period in 2011. Accordingly, the weighted average grant date fair value of share-based payments issued during the year ended December 31, 2012 was $8.05 per share as compared to $14.12 per share for the same period in 2011.

Interest and Other (Expense) Income, Net

Interest expense primarily consists of fees associated with the 2012 credit facility. Interest expense also consists of fees associated with issuing letters of credit and other financial assurances. Other income and expense consist primarily of gains or losses on transactions denominated in currencies other than our or our subsidiaries' functional currency, interest income earned on cash balances, and other non-operating income and expense. We historically have invested our cash in money market funds, treasury funds, commercial paper, and municipal bonds.

Consolidated Results of Operations

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Revenues

The following table summarizes our revenues for the years ended December 31, 2012 and 2011 (in thousands):

	December 31, 2012	December 31, 2011	Dollar Change	Percentage Change
Revenues:				
DemandSMART	$244,852	$259,150	$(14,298)	(5.5)%
EfficiencySMART, SupplySMART and Other	33,132	27,458	5,674	20.7%
Total revenues	$277,984	$286,608	$ (8,624)	(3.0)%

The overall decrease in our DemandSMART revenues was primarily attributable to changes in the following existing operating areas (dollars in thousands):

	Revenue (Decrease) Increase: December 31, 2011 to December 31, 2012
PJM	$(42,092)
New England	(14,347)
OPA	(4,396)
Australia	17,962
Act129	13,513
Texas	5,996
California	3,873
Alberta	2,680
Other (1)	2,513
Total decreased DemandSMART revenues	$(14,298)

(1) The amounts included in this category relate to net increases in various demand response programs, none of which are individually material.

The decrease in our DemandSMART revenues for the year ended December 31, 2012, as compared to 2011, was primarily attributable to less favorable pricing and a decrease in our MW delivery obligations in the PJM and ISO-NE programs, in addition to decreased energy revenues as a result of fewer demand response events that yielded energy payments and a change in the mix of energy rates. In addition, the discontinuance of PJM's ILR program in June 2012 reduced our flexibility to manage our portfolio of demand response capacity in the PJM market and negatively impacted our revenues for the year ended December 31, 2012. The decrease in DemandSMART revenues was also attributable to the termination of an ISO-NE program during the three months ended June 30, 2012, from which we derived revenues throughout 2011 compared to only six months during the year ended December 31, 2012. In addition, DemandSMART revenues declined due to the recognition of $5.3 million of previously deferred revenues during the year ended December 31, 2011 as a result of an amendment to our utility contract with OPA, or the OPA contract. There was no similar recognition of deferred revenues under the OPA contract during the year ended December 31, 2012. The decrease in DemandSMART revenues was partially offset by an increase in enrolled MW and pricing in our Western Australia program and certain of our Texas programs, including ERCOT, Centerpoint and ONCOR and an increase in enrolled MW and improved performance in our California programs. The decrease in DemandSMART revenues was also partially offset by revenue we earned from the Pennsylvania Act 129, or Act 129, programs and a demand response program in Alberta, Canada for which no revenues were recognized in 2011.

For the year ended December 31, 2012, our EfficiencySMART, SupplySMART and other revenues increased, as compared to 2011, due to continued growth in customers and contracts, the commencement of revenue recognition in 2012 that resulted from the completion of the installation phase of a $10 million EfficiencySMART data-driven energy management application for the Massachusetts Department of Energy Resources, and enhanced customer relationships that resulted from our acquisitions of Global Energy and M2M in 2011. In addition, the increase in our EfficiencySMART, SupplySMART and other revenues for the year ended December 31, 2012 was attributable to the recognition of a full year of revenues during fiscal 2012 from our acquisitions of Global Energy and M2M, both of which occurred in early 2011.

We currently expect our total DemandSMART revenues to increase during the year ending December 31, 2013, or fiscal 2013, as compared to fiscal 2012 primarily due to an increase in pricing and enrolled MW in our Western Australia demand response program, as well as an increase in PJM revenues as PJM prices return to more historical levels.

Gross Profit and Gross Margin

The following table summarizes our gross profit and gross margin percentages for our energy management applications, services and products for the years ended December 31, 2012 and 2011 (dollars in thousands):

Year Ended December 31,			
2012		2011	
Gross Profit	Gross Margin	Gross Profit	Gross Margin
$ 123,444	44.4%	$123,397	43.1%

Despite a decline in revenue, the slight increase in gross profit for the year ended December 31, 2012, as compared to 2011, was primarily due to the gross profit generated from the increase in our enrolled MW and pricing in Western Australia and the gross profit generated from our new DemandSMART arrangements in fiscal 2012 when no revenues were recognized in 2011, including our Act 129 programs and our program in Alberta, Canada. The increase in gross profit was also attributable to improved management of our portfolio of demand response capacity and an overall reduction in the percentage of revenues paid to our C&I customers. This increase in gross profit was partially offset by less favorable pricing and a decrease in enrolled MW in our PJM and ISO-NE programs, as well as the termination of an ISO-NE program during the three months ended June 30, 2012 from which we derived revenues throughout 2011. In addition, the increase in gross profit was also partially offset by the recognition of $5.3 million of revenues during the year ended December 31, 2011 related to our OPA contract for which we had recognized the associated cost of such revenues prior to 2011. There were no similar transactions during the year ended December 31, 2012.

Our gross margin during the year ended December 31, 2012 increased in comparison to 2011 due to improved management of our portfolio of demand response capacity, including the adjustment of our zonal capacity obligations through our participation in PJM incremental auctions and lower costs associated with our C&I contracts. These increases were offset by a decrease in gross margin under our OPA contract due to the recognition of revenues during the year ended December 31, 2011 in connection with the amendment to the OPA contract, for which we recognized the cost of such revenues in previous periods. The increase in our gross margin during the year ended December 31, 2012 compared to 2011 was also offset by the decrease in gross margin that resulted from the recognition of revenues during the year ended December 31, 2011 in connection with our participation in a California demand response program for which we recognized the cost of such revenues in previous periods.

We currently expect that our gross margin for the year ending December 31, 2013 will be slightly higher than our gross margin for the year ended December 31, 2012 due to the continuing improvement in the management of our portfolio of demand response capacity, as well as lower costs associated with our C&I contracts. We also expect that our gross margin for the three months ending September 30, 2013 will be the highest gross margin among our four quarterly reporting periods in fiscal 2013 due to the seasonality of the demand response industry, which is consistent with our gross margin pattern in fiscal 2012 and prior years.

Operating Expenses

The following table summarizes our operating expenses for the years ended December 31, 2012 and 2011 (dollars in thousands):

	Year Ended December 31, 2012	Year Ended December 31, 2011	Percentage Change
Operating Expenses:			
Selling and marketing	$ 55,963	$ 51,907	7.8%
General and administrative	71,643	66,773	7.3%
Research and development	16,226	14,254	13.8%
Total	$143,832	$132,934	8.2%

In certain forward capacity markets in which we participate, such as PJM, we may enable our C&I customers, meaning we may install our equipment at a C&I customer site to allow for the curtailment of MW from the electric power grid, up to twelve months in advance of enrolling the C&I customer in a particular program. As a result, there has been a trend of incurring operating expenses at the time of enablement, including salaries and related personnel costs, associated with enabling certain of our C&I customers, in advance of recognizing the corresponding revenues.

Selling and Marketing Expense

The following table summarizes our selling and marketing expenses for the years ended December 31, 2012 and 2011 (dollars in thousands):

	Year Ended December 31, 2012	Year Ended December 31, 2011	Percentage Change
Payroll and related costs	$35,374	$34,143	3.6%
Stock-based compensation	4,641	4,203	10.4%
Other	15,948	13,561	17.6%
Total	$55,963	$51,907	7.8%

The increase in payroll and related costs for the year ended December 31, 2012 compared to 2011 was primarily due to an increase in the number of selling and marketing full-time employees from 204 at December 31, 2011 to 212 at December 31, 2012. This increase was partially offset by lower commissions and a decrease in cash bonuses for fiscal 2012 as a portion of those bonuses will be settled in shares of our common stock and therefore is recorded in stock-based compensation expense. In addition, we incurred higher travel related costs of $0.5 million primarily as a result of our continued international expansion.

The increase in stock-based compensation for the year ended December 31, 2012 compared to 2011 was primarily due to a portion of the bonuses for fiscal 2012 that will be settled in shares of our common stock rather than cash and is, therefore, recorded as a component of stock-based compensation expense. This increase was offset by a lower grant date fair value of stock-based awards granted during the year ended December 31, 2012, which was lower than the grant date fair value of stock-based awards that became fully vested during the year ended December 31, 2011, as well as a reversal of stock-based compensation expense that resulted from forfeitures of a greater number of stock-based awards during the year ended December 31, 2012.

The increase in other selling and marketing expenses for the year ended December 31, 2012 compared to 2011 was due to a $1.3 million increase in amortization expense related to acquired intangible assets that resulted from our acquisition of Energy Response in July 2011, a $1.3 million increase in the allocation to selling and marketing of company-wide overhead costs, which are allocated based upon headcount, due to higher facilities and IT costs, and an increase in professional services fees of $0.7 million. This increase was partially offset by the recording in 2011 of approximately $0.5 million of impairment charges associated with the discontinued use of the trade name intangible assets acquired in connection with our acquisition of Energy Response and another immaterial acquisition that we completed in 2011, in addition to the discontinuation of certain customer relationships related to our acquisition of eQ. We did not incur any such charges in 2012. We also incurred lower marketing costs of $0.3 million in 2012 compared to 2011.

General and Administrative Expenses

The following table summarizes our general and administrative expenses for the years ended December 31, 2012 and 2011 (dollars in thousands):

	Year Ended December 31,		Percentage Change
	2012	**2011**	
Payroll and related costs	$37,538	$34,057	10.2%
Stock-based compensation	7,755	8,255	(6.1)%
Other	26,350	24,461	7.7%
Total	$71,643	$66,773	7.3%

The increase in payroll and related costs for the year ended December 31, 2012 compared to 2011 was primarily attributable to an increase in the number of general and administrative full-time employees from 322 at December 31, 2011 to 383 at December 31, 2012. This increase was partially offset by a portion of the bonuses for fiscal 2012 that will be settled in shares of our common stock rather than cash and is, therefore, recorded as a component of stock-based compensation expense.

The decrease in stock-based compensation for the year ended December 31, 2012 compared to 2011 was primarily due to the reversal of stock-based compensation expense related to the forfeiture of stock-based awards that were granted to our former chief financial officer, as well as fully-vested stock awards that were granted to our board of directors at a lower grant-date fair value in the year ended December 31, 2012 than the fair value of stock-based awards granted to them during 2011. These decreases were offset by an increase in stock-based compensation related to a portion of the bonuses for fiscal 2012 that will be settled in shares of our common stock rather than cash, which is recorded as a component of stock-based compensation expense.

The increase in other general and administrative expenses for the year ended December 31, 2012 compared to 2011 was attributable to an increase of $3.2 million in facilities expenses due to higher rent and insurance costs in addition to higher depreciation expense that resulted from a change in useful life of the leasehold improvements under our current lease, an increase of $2.5 million in higher fees mainly associated with regulatory compliance, and an increase of $0.8 million in information technology and communication costs in support of our business. The increase in other general and administrative expenses for the year ended December 31, 2012 compared to 2011 was also attributable to a lease termination charge of $1.1 million resulting from our election to terminate the operating lease for our current corporate headquarters effective June 30, 2013. These increases in other general and administrative expenses for the year ended December 31, 2012 were offset by a decrease of $3.8 million in finance charges, most of which were attributable to charges that we recorded during the year ended December 31, 2011 in connection with a certain contract that we terminated during 2011. The increase in other general and administrative expenses for the year ended December 31, 2012 was also offset by an increase of $2.1 million in the allocation to selling and marketing, and research and development of company-wide overhead costs.

Research and Development Expenses

The following table summarizes our research and development expenses for the years ended December 31, 2012 and 2011 (dollars in thousands):

	Year Ended December 31, 2012	Year Ended December 31, 2011	Percentage Change
Payroll and related costs	$ 9,172	$ 7,682	19.4%
Stock-based compensation	1,220	1,006	21.3%
Other	5,834	5,566	4.8%
Total	$16,226	$14,254	13.8%

The increase in payroll and related costs for the year ended December 31, 2012 compared to 2011 was primarily driven by an increase in the number of research and development full-time employees from 73 at December 31, 2011 to 90 at December 31, 2012, as well as an increase in salary rates per full-time employee. This increase was partially offset by an increase in capitalized application development costs primarily related to our DemandSMART application, as well as a portion of the bonuses for fiscal 2012 that will be settled in shares of our common stock rather than cash and is, therefore, recorded as a component of stock-based compensation expense.

The increase in stock-based compensation for the year ended December 31, 2012 compared to 2011 was related to a portion of the bonuses for fiscal 2012 that will be settled in shares of our common stock rather than cash and is, therefore, recorded as a component of stock-based compensation expense.

The increase in other research and development expenses for the year ended December 31, 2012 compared to 2011 was due to an increase of $0.8 million in the allocation to research and development of company-wide overhead costs which are allocated based upon headcount. The increase in other research and development expenses was also due to an increase of $0.5 million in software licensing fees. This increase was partially offset by an impairment charge of $0.5 million related to an indefinite-lived in-process research and development intangible asset and an impairment charge related to a definite-lived patent intangible asset of less than $0.1 million that were recorded in 2011 as a result of a review and realignment of our development efforts. In addition, we incurred lower professional services fees during the year ended December 31, 2012 of $0.4 million compared to 2011 and lower miscellaneous equipment expenses of $0.1 million.

Interest and Other (Expense) Income, Net

The increase in interest expense of $0.5 million for the year ended December 31, 2012 compared to 2011 was mainly attributable to the costs associated with the renegotiation of our 2012 credit facility, higher average outstanding letter of credit balances in addition to higher partner bank fees. Other income (expense), net for the year ended December 31, 2012 was primarily comprised of foreign currency gains (losses) and a nominal amount of interest income. We had approximately $21.2 million at December 31, 2012 exchange rates ($20.4 million Australian) in intercompany receivables denominated in Australian dollars that arose from the acquisition of Energy Response in July 2011. Substantially all of the foreign currency gains (losses) represent unrealized gains (losses) and, therefore, are non-cash in nature. We currently do not hedge any of our foreign currency transactions.

Income Taxes

We recorded a provision for income taxes of $1.8 million and $1.8 million for the years ended December 31, 2012 and 2011, respectively. Although our federal and state net operating loss carryforwards exceeded our taxable income for the years ended December 31, 2012 and 2011, our annual effective tax rate was greater than zero due to the following:

- estimated foreign taxes resulting from guaranteed profit allocable to our foreign subsidiaries, which have been determined to be limited-risk service providers acting on behalf of the U.S. parent for tax purposes, for which there are no tax net operating loss carryforwards;
- certain state taxes for jurisdictions where the states currently limit or disallow the utilization of net operating loss carryforwards; and
- amortization of tax deductible goodwill, which generates a deferred tax liability that cannot be offset by net operating losses or other deferred tax assets since its reversal is considered indefinite in nature.

Our effective tax rate for the year ended December 31, 2012 was 8.6% compared to an effective tax rate of 15.6% for the year ended December 31, 2011.

We review all available evidence to evaluate the recovery of our deferred tax assets, including the recent history of accumulated losses in all tax jurisdictions over the last three years, as well as our ability to generate income in future periods. As of December 31, 2012 and December 31, 2011, due to the uncertainty related to the ultimate use of our deferred income tax assets, we have provided a full valuation allowance against our U.S., Australian and New Zealand deferred tax assets.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Revenues

The following table summarizes our revenues for the years ended December 31, 2011 and 2010 (dollars in thousands):

	Year Ended December 31, 2011	Year Ended December 31, 2010	Dollar Change	Percentage Change
Revenues:				
DemandSMART	$259,150	$264,608	$ (5,458)	(2.1)%
EfficiencySMART, SupplySMART and Other	27,458	15,549	11,909	76.6%
Total revenues	$286,608	$280,157	$ 6,451	2.3%

For the year ended December 31, 2011, our demand response revenues decreased by $5.5 million, or 2%, as compared to the year ended December 31, 2010. The decrease in our DemandSMART revenues was primarily attributable to changes in the following existing operating areas (dollars in thousands):

	Revenue Increase (Decrease): December 31, 2010 to December 31, 2011
PJM	$(14,431)
New England	(14,123)
New York	(2,601)
Public Service Company of New Mexico, or PNM	(560)
OPA	12,204
California	5,090
Australia	3,725
ERCOT	1,793
XCEL Energy	959
Salt River Project, or SRP	880
UK National Grid	798
Tucson Electric Power, or TEP	646
Other(1)	162
Total decreased demand response revenues	$ (5,458)

The decrease in our DemandSMART revenues during the year ended December 31, 2011 compared to 2010 was primarily attributable to less favorable pricing in the PJM and New York markets, as well as a decrease in MW enrolled in our ISO-NE program and less favorable pricing compared to 2010 due to the commencement of a new ISO-NE program in June 2010. The decrease in DemandSMART revenues was also partially attributable to fewer demand response events being called by PJM during the year ended December 31, 2011, which resulted in decreased energy payments, as compared to 2010. The decrease in DemandSMART revenues was also partially attributable to a decrease in MW enrolled in our PNM program during the year ended December 31, 2011 as compared to 2010. The decrease in DemandSMART revenues was partially offset by an increase in revenues recognized as a result of amendments to the OPA contract during the year ended December 31, 2011 that resulted in the recognition of $5.3 million of revenues during the year that had been previously deferred. The decrease in DemandSMART revenues was also partially offset by stronger demand response event performance in our California demand response programs, our ability to recognize revenues based on the finalization of performance in a certain California demand response program, and an increase in our enrolled MW in the XCEL Energy, SRP, UK National Grid, and certain other demand response programs in which we participate. The decrease in DemandSMART revenues was also partially offset by our participation in demand response programs in Australia and the TEP demand response program. We did not receive any revenues related to the Australia or TEP programs during the year ended December 31, 2010.

For the year ended December 31, 2011, our EfficiencySMART, SupplySMART and other revenues increased by $11.9 million compared to 2010 primarily due to our acquisitions of Global Energy and M2M, both of which occurred in January 2011. In addition, we completed a certain EfficiencySMART project during 2011, which resulted in the recognition of $0.6 million of revenues that had been previously deferred.

Gross Profit and Gross Margin

The following table summarizes our gross profit and gross margin percentages for our energy management applications, services and products for the years ended December 31, 2011 and 2010 (dollars in thousands):

Year Ended December 31,			
2011		2010	
Gross Profit	Gross Margin	Gross Profit	Gross Margin
$ 123,397	43.1%	$120,325	42.9%

The increase in gross profit during the year ended December 31, 2011 compared to 2010 was primarily due to our ability to recognize revenues that had previously been deferred in connection with the OPA contract, pursuant to which we recognized the cost of such revenues in prior periods due to the uncertainty of the realizability of these costs. The increase in gross profit was also partially attributable to stronger demand response event performance in certain of the demand response programs in which we participate, including ISO-NE, which in some cases resulted in increased energy payments for the year ended December 31, 2011 compared to 2010, as well as our ability to recognize revenues based on the finalization of performance in a certain California demand response program for which the corresponding cost of revenues were recorded during the year ended December 31, 2010. The acquisitions that we completed in 2011 also contributed to the increase in gross profit for the year ended December 31, 2011. The increase in gross profit was partially offset by less favorable pricing in PJM and ISO-NE, as well as fewer demand response events being called by PJM during the year ended December 31, 2011, which resulted in decreased energy payments from PJM compared to 2010.

The slight increase in gross margin during the year ended December 31, 2011, compared to 2010 was primarily due to the recognition of revenues in connection with the OPA contract, pursuant to which we recognized the cost of revenues in prior periods due to the uncertainty of the realizability of these costs. The increase was partially offset by less favorable pricing in PJM and ISO-NE, which was not entirely offset by lower payments to our C&I customers.

Operating Expenses

The following table summarizes our operating expenses for the years ended December 31, 2011 and 2010 (dollars in thousands):

	Year Ended December 31, 2011	Year Ended December 31, 2010	Percentage Change
Operating Expenses:			
Selling and marketing	$ 51,907	$ 44,029	17.9%
General and administrative	66,773	54,983	21.4%
Research and development	14,254	10,097	41.2%
Total	$132,934	$109,109	21.8%

In certain forward capacity markets in which we participate, such as PJM, we may enable our C&I customers, meaning we may install our equipment at a C&I customer site to allow for the curtailment of MW from the electric power grid, up to twelve months in advance of enrolling the C&I customer in a particular demand response program. As a result, there has been a trend of increasing operating expenses at the time of enablement, including salaries and related personnel costs associated with enabling certain of our C&I customers, in advance of recognizing the corresponding revenues.

The increase in payroll and related costs within our operating expenses for the year ended December 31, 2011 compared to 2010 was primarily driven by an increase in headcount from 484 full time employees at December 31, 2010 to 599 full time employees at December 31, 2011, which was substantially due to the acquisitions that we completed in 2011.

Selling and Marketing Expense

The following table summarizes our selling and marketing expenses for the years ended December 31, 2011 and 2010 (dollars in thousands):

	Year Ended December 31,		Percentage Change
	2011	2010	
Payroll and related costs	$34,143	$29,765	14.7%
Stock-based compensation	4,203	4,583	(8.3)%
Other	13,561	9,681	40.1%
Total	$51,907	$44,029	17.9%

The increase in payroll and related costs for the year ended December 31, 2011 compared to 2010 was primarily due to an increase in the number of selling and marketing full-time employees from 176 at December 31, 2010 to 204 at December 31, 2011 which was partially offset by a decrease of $0.6 million in sales commissions payable to employees in our sales organization for the year ended December 31, 2011.

The decrease in stock-based compensation for the year ended December 31, 2011 compared to 2010 was primarily due to significant stock-based awards granted in 2007 that became fully vested prior to June 30, 2011. The decrease was also partially attributable to the reversal of stock-based compensation expense that resulted from forfeitures of a greater number of stock-based awards in connection with an increase in our attrition rate. These decreases were offset by a full year of stock-based compensation expense related to awards granted during the year ended December 31, 2010 and by stock-based compensation expense related to awards granted during the year ended December 31, 2011.

The increase in other selling and marketing expenses for the year ended December 31, 2011 compared to 2010 was primarily attributable to an increase in amortization expense of $3.5 million due to the customer relationship and trade name intangible assets acquired in connection with the acquisitions we completed in 2011. During the year ended December 31, 2011, we recorded an impairment charge of $0.2 million related to the discontinued use of the trade name intangible assets acquired in connection with our acquisition of Energy Response and another immaterial acquisition that we completed in 2011, contributing to the increase in selling and marketing expenses for the year ended December 31, 2011 compared to 2010. In addition, during the year ended December 31, 2011, as a result of the discontinuation of certain customer relationships related to our acquisition of eQ, we recorded an impairment charge of $0.3 million during the three month period ended December 31, 2011. The increase in other selling and marketing expenses for the year ended December 31, 2011 compared to 2010 was also partially attributable to an increase in professional services fees of $0.2 million. The increase in other selling and marketing expenses for the year ended December 31, 2011 was offset by a decrease in marketing costs of $0.5 million due to our rebranding efforts that took place in 2010.

General and Administrative Expenses

The following table summarizes our general and administrative expenses for the years ended December 31, 2011 and 2010 (dollars in thousands):

	Year Ended December 31,		Percentage Change
	2011	2010	
Payroll and related costs	$34,057	$28,709	18.6%
Stock-based compensation	8,255	10,252	(19.5)%
Other	24,461	16,022	52.7%
Total	$66,773	$54,983	21.4%

The increase in general and administrative expenses for the year ended December 31, 2011 compared to 2010 was partially due to an increase in the number of general and administrative full-time employees from 250 at December 31, 2010 to 322 at December 31, 2011. The increase in headcount was partly offset by the timing of the hiring of those new full-time employees during 2011.

The decrease in stock-based compensation for the year ended December 31, 2011 compared to 2010 was primarily due to prior period stock-based awards that became fully vested in the first half of 2011 and the reversal of stock-based compensation expense that resulted from forfeitures of a greater number of stock-based awards in connection with an increase in our attrition rate. The decrease in stock-based compensation expense from 2010 was also partially attributable to fully-vested stock awards granted to our board of directors during the year ended December 31, 2011 with a lower grant-date fair value than the same amount of fully-vested stock awards granted during 2010.

The increase in other general and administrative expenses for the year ended December 31, 2011 compared to 2010 was primarily attributable to a $4.3 million increase in finance costs due to charges that we recorded in connection with a certain contract that we terminated during the year ended December 31, 2011. As a result of this termination, we recorded charges of $4.1 million during the year ended December 31, 2011, which represented the $3.2 million paid upon the termination and $0.9 million that had been previously capitalized. In addition, the increase in other general and administrative expenses for the year ended December 31, 2011 compared to 2010 was also due to an increase in professional services fees of $1.5 million incurred in connection with the integration of the acquisitions that we completed in 2011, technology and communication costs of $1.3 million due to increased software licensing fees and computer supplies, and an increase in facility costs of $1.3 million due to the expansion of our office space as a result of our recent acquisitions.

Research and Development Expenses

The following table summarizes our research and development expenses for the years ended December 31, 2011 and 2010 (dollars in thousands):

	Year Ended December 31,		Percentage
	2011	**2010**	**Change**
Payroll and related costs	$ 7,682	$ 5,517	39.2%
Stock-based compensation	1,006	907	10.9%
Other	5,566	3,673	51.5%
Total	$14,254	$10,097	41.2%

The increase in research and development expenses for the year ended December 31, 2011 compared to 2010 was primarily driven by the costs associated with an increase in the number of research and development full-time employees from 58 at December 31, 2010 to 73 at December 31, 2011 and the timing associated with our hiring of new full-time employees during 2011 compared to 2010, as well as an increase in salary rates per full-time employee. The increase was offset by an increase in capitalized internal payroll and related costs of $0.3 million for the year ended December 31, 2011.

The increase in stock-based compensation for the year ended December 31, 2011 compared to 2010 was primarily due to costs related to equity awards granted to new employees during 2011, including a senior level employee.

The increase in other research and development expenses for the year ended December 31, 2011 compared to 2010 was attributable to a $0.6 million increase in technology and communications expenses related to software licensing fees and a $0.5 million impairment charge. This increase was also attributable to an increase in the allocation of facility costs of $0.2 million due to the expansion of our office space as a result of recent acquisitions, an increase of $0.4 million in professional services fees related to our intellectual property and an increase of $0.2 million in miscellaneous equipment expenses as a result of the expansion of our hardware product offerings.

During the three months ended December 31, 2011, as a result of our review and realignment of our development efforts, we abandoned our efforts to complete the development of a certain in-process research and development indefinite-lived intangible asset related to our acquisition of Zox. As a result, we recorded an impairment charge related to this indefinite-lived in-process research and development intangible asset of $0.5 million and an impairment charge related to the associated definite-lived patent intangible asset of less than $0.1 million.

Interest and Other (Expense) Income, Net

Interest expense for the year ended December 31, 2011 includes amortization of capitalized debt issuance costs, interest on our outstanding capital leases and letters of credit origination fees. The increase in interest expense for the year ended December 31, 2011 compared to 2010 was due to the amortization of capitalized debt issuance costs associated with our previously outstanding $75.0 million senior secured revolving credit facility, as amended, that we and one of our subsidiaries entered into with SVB and a certain other financial institution in April 2011, which we refer to as the 2011 credit facility, which were significantly higher than the amortization of debt issuance costs associated with our previously outstanding $35.0 million secured revolving credit and term loan facility that we and one of our subsidiaries entered into with SVB in August 2008.

Other expense, net for the year ended December 31, 2011 was primarily comprised of foreign currency losses related to certain intercompany receivables denominated in foreign currencies. Other expense, net for the year ended December 31, 2010 was primarily comprised of a nominal amount of foreign currency losses related to certain intercompany receivables denominated in foreign currencies offset by a nominal amount of interest income. The significant increase in losses arising from transactions denominated in foreign currencies for the year ended December 31, 2011 compared to 2010 was due to the significant increase in foreign denominated intercompany receivables held by us from one of our Australian subsidiaries, primarily as a result of the funding provided to complete the acquisition of Energy Response, and the strengthening of the United States dollar as compared to the Australian dollar during the year ended December 31, 2011. As of December 31, 2011, we had an intercompany receivable from our Australian subsidiary that is denominated in Australian dollars and not deemed to be of a "long-term investment" nature totaling $33.7 million at December 31, 2011 exchange rates ($33.1 million Australian). The significant increase in losses arising from transactions denominated in foreign currencies was primarily unrealized losses and therefore a non-cash expense. We did not engage in any currency hedging transactions during the year ended December 31, 2011.

Income Taxes

We recorded a provision for income taxes of $1.8 million and $0.8 million for the years ended December 31, 2011 and 2010, respectively. Although our federal and state net operating loss carryforwards exceeded our taxable income for the years ended December 31, 2011 and 2010, our annual effective tax rate was greater than zero due to the following:

- estimated foreign taxes resulting from guaranteed profit allocable to our foreign subsidiaries, which have been determined to be limited-risk service providers acting on behalf of the U.S. parent for tax purposes, for which there are no tax net operating loss carryforwards;
- certain state taxes for jurisdictions where the states currently limit or disallow the utilization of net operating loss carryforwards; and
- amortization of tax deductible goodwill, which generates a deferred tax liability that cannot be offset by net operating losses or other deferred tax assets since its reversal is considered indefinite in nature.

Our effective tax rate for the year ended December 31, 2011 was 15.6% compared to an effective tax rate of 8.0% for the year ended December 31, 2010.

We review all available evidence to evaluate the recovery of our deferred tax assets, including the recent history of accumulated losses in all tax jurisdictions over the last three years, as well as our ability to generate income in future periods. As of December 31, 2011 and December 31, 2010, due to the uncertainty related to the ultimate use of our deferred income tax assets, we have provided a full valuation allowance against these U.S. deferred tax assets.

Liquidity and Capital Resources

Overview

We have generated significant cumulative losses since inception. As of December 31, 2012, we had an accumulated deficit of $103.4 million. As of December 31, 2012, our principal sources of liquidity were cash and cash equivalents totaling $115.0 million, an increase of $27.7 million from the December 31, 2011 balance of $87.3 million. At December 31, 2012 and December 31, 2011, the majority of our excess cash was invested in money market funds.

We believe our existing cash and cash equivalents at December 31, 2012 and our anticipated net cash flows from operating activities will be sufficient to meet our anticipated cash needs, including investing activities, for at least the next 12 months. Our future working capital requirements will depend on many factors, including, without limitation, the rate at which we sell our energy management applications, services and products to customers and the increasing rate at which letters of credit or security deposits are required by electric power grid operators and utilities, the introduction and market acceptance of new energy management applications, services and products, the expansion of our sales and marketing and research and development activities, and the geographic expansion of our business operations. To the extent that our cash and cash equivalents and our anticipated cash flows from operating activities are insufficient to fund our future activities or planned future acquisitions, we may be required to raise additional funds through bank credit arrangements, including the potential expansion, renewal or replacement of the 2012 credit facility, or public or private equity or debt financings. We also may raise additional funds in the event we determine in the future to effect one or more acquisitions of businesses, technologies or products. In addition, we may elect to raise additional funds even before we need them if the conditions for raising capital are favorable. Any equity or equity-linked financing could be dilutive to existing stockholders. In the event we require additional cash resources we may not be able to obtain bank credit arrangements or complete any equity or debt financing on terms acceptable to us or at all.

If we fail to extend, renew or replace the 2012 credit facility and we still have letters of credit issued and outstanding under the 2012 credit facility when it matures on April 15, 2013, we will be required to post up to 105% of the value of the letters of credit in cash with SVB to collateralize those letters of credit.

Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2012, 2011 and 2010 (dollars in thousands):

	Year Ended December 31,		
	2012	2011	2010
Cash flows provided by operating activities	$31,011	$ 27,637	$ 45,148
Cash flows used in investing activities	(3,585)	(95,516)	(15,424)
Cash flows provided by financing activities	356	1,997	3,974
Effects of exchange rate changes on cash	(38)	(237)	(21)
Net change in cash and cash equivalents	$27,744	$(66,119)	$ 33,677

Cash Flows Provided by Operating Activities

Cash provided by operating activities primarily consists of net (loss) income adjusted for certain non-cash items including depreciation and amortization, stock-based compensation expense, and the effect of changes in working capital and other activities.

Cash provided by operating activities for the year ended December 31, 2012 was approximately $31.0 million and consisted of a net loss of $22.3 million, offset by $42.3 million of non-cash items and $11.0 million of net cash provided by working capital and other activities. The non-cash items primarily consisted of depreciation and amortization, stock-based compensation expense, impairment charges, unrealized foreign exchange transaction gains, deferred taxes and non-cash interest expense. Cash provided by working capital and other activities consisted of a decrease of $19.2 million in unbilled revenues relating to the PJM demand response market, a decrease in prepaid expenses and other assets of $2.9 million, an increase of $22.5 million in deferred revenue, an increase of $1.4 million in accrued payroll and related expenses and an increase of $1.6 million in other noncurrent liabilities. These amounts were offset by cash used in working capital and other activities consisting of an increase in accounts receivable of $19.5 million due to the timing of cash receipts under the demand response programs in which we participate, an increase in capitalized incremental direct customer contract costs of $5.7 million, a decrease in accrued capacity payments of $9.2 million, the majority of which was related to the PJM demand response market and a decrease of $2.4 million in accounts payable, accrued performance adjustments and accrued expenses primarily due to the repayment of certain accrued performance adjustments.

Cash provided by operating activities for the year ended December 31, 2011 was approximately $27.6 million and consisted of a net loss of $13.4 million and $0.5 million of net cash used in working capital and other activities offset by $41.5 million of non-cash items, primarily consisting of depreciation and amortization, deferred taxes, stock-based compensation expense, property and equipment and intangible assets impairment charges, and unrealized foreign exchange losses. Cash used in working capital and other operating activities consisted of a decrease in accrued capacity payments of $7.4 million relating primarily to the decrease in PJM revenues and therefore the associated decrease in capacity payments to C&I customers from 2010 to 2011, a decrease of $2.1 million in accounts payable and accrued expenses and other current liabilities due to the timing of payments, an increase in other assets of $3.8 million, an increase in prepaid expenses and other current assets of $5.0 million, and a decrease in other noncurrent liabilities of $0.2 million. These amounts were offset by cash provided by working capital and other operating activities consisting of a decrease of $7.0 million in unbilled revenues relating to the PJM demand response market, a decrease of $2.7 million in accounts receivable due to the timing of cash receipts under the demand response programs in which we participate, an increase of $7.0 million in deferred revenue, and an increase of $1.3 million in accrued payroll and related expenses.

Cash provided by operating activities for the year ended December 31, 2010 was $45.1 million and consisted of net income of $9.6 million, $33.9 million of non-cash items, primarily depreciation and amortization, deferred taxes, stock-based compensation expense and impairment of property and equipment, and $1.6 million of net cash used in working capital and other activities. Cash used in working capital and other operating activities consisted of an increase of $32.8 million in unbilled revenues relating to the PJM demand response market, an increase of $4.9 million in accounts receivable due to the timing of cash receipts under the programs in which we participate and an increase in prepaid expenses and other assets of $0.7 million. These amounts were offset by cash provided by working capital and other activities which reflected an increase of $2.2 million in accrued payroll and related expenses, an increase of $5.8 million in accounts payable and accrued expenses due to the timing of payments, an increase in accrued capacity payments of $25.2 million, the majority of which was related to the PJM demand response market, and an increase of $6.8 million in deferred revenue.

Cash Flows Used in Investing Activities

Cash used in investing activities was $3.6 million for the year ended December 31, 2012. During the year ended December 31, 2012, we incurred $15.9 million in capital expenditures primarily related to the purchase of office and IT equipment, capitalized internal use software costs, demand response equipment and other miscellaneous capital expenditures. In addition our restricted cash and deposits decreased by $12.4 million due to a decline in deposits principally related to the financial assurances required for the demand response programs in which we participated, as these deposits were replaced with letters of credit.

Cash used in investing activities was $95.5 million for the year ended December 31, 2011. During the year ended December 31, 2011, we acquired Global Energy for a purchase price of $26.7 million, of which we paid $19.9 million in cash, M2M for a purchase price of $28.6 million, of which we paid $17.5 million in cash, and Energy Response for a purchase price of $30.1 million, of which we paid $27.3 million in cash, and we completed another immaterial acquisition for a purchase price of $5.2 million, of which we paid $3.9 million in cash. The net cash acquired from these acquisitions was $1.1 million. Additionally, our cash investments included the cash portion of the acquisition contingent consideration for Cogent of $1.5 million. Our other principal cash investments during the year ended December 31, 2011 related to capitalized internal use software costs used to build out and expand our energy management applications, services and products and purchases of property and equipment. We incurred $17.6 million in capital expenditures primarily related to the purchase of office equipment, demand response equipment and other miscellaneous expenditures. In addition, during the year ended December 31, 2011, our deposits increased by $8.4 million primarily due to financial assurance requirements related to our demand response programs in Australia and our long-term assets increased by $0.5 million due to financing costs in connection with the 2011 credit facility.

Cash used in investing activities was $15.4 million for the year ended December 31, 2010. Our principal cash investments during the year ended December 31, 2010, which totaled $19.4 million, related to capitalizing internal use software costs used to build out and expand our energy management applications and services, and purchases of property and equipment. During the year ended December 31, 2010, we acquired SmallFoot and Zox for a purchase price of $1.4 million, of which $1.1 million was paid in cash. Additionally, our cash investments included the cash portion of the earn-out payment due in connection with our acquisition of SRC of $0.9 million. We had a decrease in restricted cash and deposits of $6.0 million primarily as a result of demand response event performance in July 2010 under a certain open market program in which we participated, resulting in our restricted cash becoming unrestricted in July 2010.

Cash Flows Provided by Financing Activities

Cash provided by financing activities was $0.4 million, $2.0 million and $4.0 million for the years ended December 31, 2012, 2011 and 2010, respectively, and consisted primarily of proceeds that we received from exercises of options to purchase shares of our common stock.

Credit Facility Borrowings

Subject to continued compliance with the covenants contained in our 2012 credit facility, the full amount of the 2012 credit facility may be available for issuances of letters of credit and up to $5.0 million of the 2012 credit facility may be available for swing line loans. We are charged letter of credit fees in connection with the issuance or renewal of letters of credit equal to 2% of each letter of credit. The interest on revolving loans under the 2012 credit facility will accrue, at our election, at either (i) the Eurodollar Rate with respect to the relevant interest period plus 2.00% or (ii) the ABR (defined as the highest of (x) the "prime rate" as quoted in the *Wall Street Journal*, (y) the Federal Funds Effective Rate plus 0.50% and (z) the Eurodollar Rate for a one-month interest period plus 1.00%) plus 1.00%. We expense the interest and letter of credit fees under the 2012 credit facility, as applicable, in the period incurred. The obligations under the 2012 credit facility are secured by all of our domestic assets and the assets of several of our subsidiaries, excluding our foreign subsidiaries. The 2012 credit facility terminates and all amounts outstanding thereunder are due and payable in full on April 15, 2013. We incurred total financing costs of $0.5 million in connection with the 2012 credit facility, which were deferred and are being amortized to interest expense over the term of the 2012 credit facility, or through April 15, 2013.

The 2012 credit facility contains customary terms and conditions for credit facilities of this type, including, among other things, restrictions on our ability to incur additional indebtedness, create liens, enter into transactions with affiliates, transfer assets, make certain acquisitions, pay dividends or make distributions on, or repurchase, our common stock, consolidate or merge with other entities, or undergo a change in control. In addition, we are required to meet certain monthly and quarterly financial covenants customary with this type of credit facility.

The 2012 credit facility contains customary events of default, including for payment defaults, breaches of representations, breaches of affirmative or negative covenants, cross defaults to other material indebtedness, bankruptcy and failure to discharge certain judgments. If a default occurs and is not cured within any applicable cure period or is not waived, SVB may accelerate our obligations under the 2012 credit facility. If we are determined to be in default then any amounts outstanding under the 2012 credit facility would become immediately due and payable and we would be required to collateralize with cash any outstanding letters of credit up to 105% of the amounts outstanding.

Off-Balance Sheet Arrangements

As of December 31, 2012, we did not have any off-balance sheet arrangements, as defined in Item 303(a)(4)(ii) of Regulation S-K, that have or are reasonably likely to have a current or future effect on our financial condition, changes in our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors. We have issued letters of credit in the ordinary course of our business in order to participate in certain demand response programs. As of December 31, 2012, we had outstanding letters of credit totaling $42.6 million. For information on these commitments and contingent obligations, see "Liquidity and Capital Resources — Credit Facility Borrowings" above and Note 12 to our consolidated financial statements contained herein.

Additional Information

Non-GAAP Financial Measures

To supplement our consolidated financial statements presented on a GAAP basis, we disclose certain non-GAAP measures that exclude certain amounts, including non-GAAP net (loss) income, non-GAAP net (loss) income per share, adjusted EBITDA and free cash flow. These non-GAAP measures are not in accordance with, or an alternative for, generally accepted accounting principles in the United States.

The GAAP measure most comparable to non-GAAP net (loss) income is GAAP net (loss) income; the GAAP measure most comparable to non-GAAP net (loss) income per share is GAAP net (loss) income per share; the GAAP measure most comparable to adjusted EBITDA is GAAP net (loss) income; and the GAAP measure most comparable to free cash flow is net cash provided by (used in) operating activities. Reconciliations of each of these non-GAAP financial measures to the corresponding GAAP measure are included below.

Use and Economic Substance of Non-GAAP Financial Measures

Management uses these non-GAAP measures when evaluating our operating performance and for internal planning and forecasting purposes. Management believes that such measures help indicate underlying trends in our business, are important in comparing current results with prior period results, and are useful to investors and financial analysts in assessing our operating performance. For example, management considers non-GAAP net (loss) income to be an important indicator of the overall performance because it eliminates the effects of events that are either not part of our core operations or are non-cash compensation expenses. In addition, management considers adjusted EBITDA to be an important indicator of our operational strength and performance of our business and a good measure of our historical operating trend. Moreover, management considers free cash flow to be an indicator of our operating trend and performance of our business.

The following is an explanation of the non-GAAP measures that we utilize, including the adjustments that management excluded as part of the non-GAAP measures for the years ended December 31, 2012, 2011 and 2010, respectively, as well as reasons for excluding these individual items:

- Management defines non-GAAP net (loss) income as net income (loss) before expenses related to stock-based compensation and amortization expenses related to acquisition-related intangible assets, net of related tax effects.
- Management defines adjusted EBITDA as net (loss) income, excluding depreciation, amortization, stock-based compensation, interest, income taxes and other income (expense). Adjusted EBITDA eliminates items that are either not part of our core operations or do not require a cash outlay, such as stock-based compensation. Adjusted EBITDA also excludes depreciation and amortization expense, which is based on our estimate of the useful life of tangible and intangible assets. These estimates could vary from actual performance of the asset, are based on historic cost incurred to build out our deployed network and may not be indicative of current or future capital expenditures.
- Management defines free cash flow as net cash provided by (used in) operating activities less capital expenditures. Management defines capital expenditures as purchases of property and equipment, which includes capitalization of internal-use software development costs.

Material Limitations Associated with the Use of Non-GAAP Financial Measures

Non-GAAP net (loss) income, non-GAAP net (loss) income per share, adjusted EBITDA and free cash flow may have limitations as analytical tools. The non-GAAP financial information presented here should be considered in conjunction with, and not as a substitute for or superior to the financial information presented in accordance with GAAP and should not be considered measures of our liquidity. There are significant limitations associated with the use of non-GAAP financial measures. Further, these measures may differ from the non-GAAP information, even where similarly titled, used by other companies and therefore should not be used to compare our performance to that of other companies.

Non-GAAP Net (Loss) Income and Non-GAAP Net (Loss) Income per Share

Net loss for the year ended December 31, 2012 was $22.3 million, or $0.84 per basic and diluted share, compared to a net loss of $13.4 million, or $0.52 per basic and diluted share for the year ended December 31, 2011, and net income of $9.6 million, or $0.39 per basic share and $0.37 per diluted share, for the year ended December 31, 2010. Excluding stock-based compensation charges and amortization of expenses related to acquisition-related assets, net of tax effects, non-GAAP net loss for the year ended December 31, 2012 was $1.4 million, or $0.05 per basic and diluted share, compared to a non-GAAP net income of $5.9 million, or $0.23 per basic share and $0.22 per diluted share, for the year ended December 31, 2011, and a non-GAAP net income of $25.4 million, or $1.03 per basic share and $0.97 per diluted share, for the year ended December 31, 2010. The reconciliation of GAAP net (loss) income to non-GAAP net (loss) income is set forth below:

	Year Ended December 31,		
	2012	2011	2010
	(In thousands, except share and per share data)		
GAAP net (loss) income	$ (22,293)	$ (13,383)	$ 9,577
ADD: Stock–based compensation	13,616	13,464	15,742
ADD: Amortization expense of acquired intangible assets	7,241	5,856	1,452
LESS: Income tax effect on Non-GAAP adjustments (1)	—	—	(1,380)
Non-GAAP net (loss) income	$ (1,436)	$ 5,937	$ 25,391
GAAP net (loss) income per basic share	$ (0.84)	$ (0.52)	$ 0.39
ADD: Stock–based compensation	0.52	0.52	0.64
ADD: Amortization expense of acquired intangible assets	0.27	0.23	0.06
LESS: Income tax effect on Non-GAAP adjustments (1)	—	—	(0.06)
Non-GAAP net (loss) income per basic share	$ (0.05)	$ 0.23	$ 1.03
GAAP net (loss) income per diluted share	$ (0.84)	$ (0.52)	$ 0.37
ADD: Stock–based compensation	0.52	0.52	0.60
ADD: Amortization expense of acquired intangible assets	0.27	0.23	0.05
LESS: Income tax effect on Non-GAAP adjustments (1)	—	—	(0.05)
LESS: Dilutive impact on weighted average common stock equivalents	—	(0.01)	—
Non-GAAP net (loss) income per diluted share	$ (0.05)	$ 0.22	$ 0.97
Weighted average number of common shares outstanding			
Basic	26,551,234	25,799,494	24,611,729
Diluted	26,551,234	26,766,359	26,054,162

(1) Represents the increase in the income tax provision recorded for the year ended December 31, 2010 based on our effective tax rate for the year ended December 31, 2010. The non-GAAP adjustments would have no impact on the provision for income taxes recorded for the years ended December 31, 2012 and 2011.

Adjusted EBITDA

Adjusted EBITDA was $ 18.4 million, $ 26.0 million, and $42.8 million for the years ended December 31, 2012, 2011 and 2010, respectively.

The reconciliation of adjusted EBITDA to net (loss) income is set forth below:

	Year Ended December 31,		
	2012	2011	2010
Net (loss) income	$(22,293)	$(13,383)	$ 9,577
Add back:			
Depreciation and amortization	25,218	22,043	15,866
Stock-based compensation expense	13,616	13,464	15,742
Other (income) expense	(1,457)	987	85
Interest expense	1,591	1,053	718
Provision for income tax	1,771	1,806	836
Adjusted EBITDA	$ 18,446	$ 25,970	$42,824

Free Cash Flow

Net cash provided by operating activities was $31.0 million, $27.6 million and $45.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. We generated $15.2 million, $10.0 million and $25.8 million of free cash flow for the years ended December 31, 2012, 2011 and 2010, respectively. The reconciliation of free cash flow to net cash provided by operating activities is set forth below:

	Year Ended December 31,		
	2012	2011	2010
Net cash provided by operating activities	$ 31,011	$ 27,637	$ 45,148
Subtract:			
Purchases of property and equipment	(15,854)	(17,613)	(19,394)
Free cash flow	$ 15,157	$ 10,024	$ 25,754

Critical Accounting Policies and Use of Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. On an on-going basis, we evaluate our estimates, including those related to revenue recognition for multiple element arrangements, allowance for doubtful accounts, valuations and purchase price allocations related to business combinations, expected future cash flows including growth rates, discount rates, terminal values and other assumptions and estimates used to evaluate the recoverability of long-lived assets and goodwill, estimated fair values of intangible assets and goodwill, amortization methods and periods, certain accrued expenses and other related charges, stock-based compensation, contingent liabilities, tax reserves and recoverability of our deferred tax assets and related valuation allowance. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates if past experience or other assumptions do not turn out to be substantially accurate. Any differences could have a material impact on our financial condition and results of operations.

We believe that of our significant accounting policies, which are described in Note 1 to our consolidated financial statements beginning on page F-1 of Appendix A to this Annual Report on Form 10-K, the following accounting policies involve a greater degree of judgment and complexity. Accordingly, these are the policies we believe are the most critical to aid in fully understanding and evaluating our financial condition and results of operations.

Revenue Recognition

We recognize revenues in accordance with ASC 605, *Revenue Recognition,* or ASC 605. In all of our arrangements, we do not recognize any revenues until persuasive evidence of an arrangement exists, delivery has occurred, the fee is fixed or determinable, and we deem collection to be reasonably assured. In making these judgments, we evaluate these criteria as follows:

- ***Evidence of an arrangement.*** We consider a definitive agreement signed by the customer and us or an arrangement enforceable under the rules of an open market bidding program to be representative of persuasive evidence of an arrangement.
- ***Delivery has occurred.*** We consider delivery to have occurred when service has been delivered to the customer and no post-delivery obligations exist. In instances where customer acceptance is required, delivery is deemed to have occurred when customer acceptance has been achieved.
- ***Fees are fixed or determinable.*** We consider the fee to be fixed or determinable unless the fee is subject to refund or adjustment or is not payable within normal payment terms. If the fee is subject to refund or adjustment and we cannot reliably estimate this amount, we recognize revenues when the right to a refund or adjustment lapses. If offered payment terms significantly exceed our normal terms, we recognize revenues as the amounts become due and payable or upon the receipt of cash.
- ***Collection is reasonably assured.*** We conduct a credit review at the inception of an arrangement to determine the creditworthiness of the customer. Collection is reasonably assured if, based upon our evaluation, we expect that the customer will be able to pay amounts under the arrangement as payments become due. If we determine that collection is not reasonably assured, revenues are deferred and recognized upon the receipt of cash.

We enter into contracts and open market bidding programs with utilities and electric power grid operators to provide demand response applications and services. Demand response revenues consist of two elements: revenue earned based on our ability to deliver committed capacity to our electric power grid operator and utility customers, which we refer to as capacity revenue; and revenue earned based on additional payments made to us for the amount of energy usage actually curtailed from the grid during a demand response event, which we refer to as energy event revenue.

We recognize demand response revenue when we have provided verification to the electric power grid operator or utility of our ability to deliver the committed capacity which entitles us to payments under the utility contract or open market program. Committed capacity is generally verified through the results of an actual demand response event or a measurement and verification test. Once the capacity amount has been verified, the revenue is recognized and future revenue becomes fixed or determinable and is recognized monthly until the next demand response event or test. In subsequent verification events, if our verified capacity is below the previously verified amount, the electric power grid operator or utility customer will reduce future payments based on the adjusted verified capacity amounts. Ongoing demand response revenue recognized between demand response events or tests that are not subject to penalty or customer refund are recognized in revenue. If the revenue is subject to refund and the amount of refund cannot be reliably estimated, the revenue is deferred until the right of refund lapses.

We have evaluated the factors within ASC 605 regarding gross versus net revenue reporting for our demand response revenues and payments to C&I customers. Based on the evaluation of the factors within ASC 605, we determined that all of the applicable indicators of gross revenue reporting were met. These applicable indicators of gross revenue reporting included, but were not limited to, the following:

- We are the primary obligor in our arrangements with electric power grid operators and utility customers because we provide demand response services directly to electric power grid operators and utilities under long-term contracts or pursuant to open market programs and contract separately with C&I customers to deliver such services. We manage all interactions with the electric power grid operators and utilities, while C&I customers do not interact with the electric power grid operators and utilities. In addition, we assume the entire performance risk under arrangements with electric power grid operators and utility customers, including the posting of financial assurance to assure timely delivery of committed capacity with no corresponding financial assurance received from C&I customers. In the event of a shortfall in delivered committed capacity, we are responsible for all penalties assessed by the electric power grid operators and utilities without regard for any recourse we may have with our C&I customers.

- We have latitude in establishing pricing, as the pricing under our arrangements with electric power grid operators and utilities is negotiated through a contract proposal and contracting process or determined through a capacity auction. We then separately negotiate payment to C&I customers and have complete discretion in the contracting process with the C&I customer.
- We have complete discretion in determining the supplier (C&I customer) to provide the demand response services, provided that the C&I customer is located in the same region as the applicable electric power grid operator or utility.
- We are involved in both the determination of service specifications and performing part of the services, including the installation of metering and other equipment for the monitoring, data gathering and measurement of performance, as well as, in certain circumstances, the remote control of C&I customer loads.

As a result, we determined that we earn revenue (as a principal) from the delivery of demand response services to electric power grid operators and utility customers and we record the amounts billed to the electric power grid operators and utility customers as gross demand response revenues and the amounts paid to C&I customers as cost of revenues.

In the PJM open market program in which we participate, the program year operates on a June to May basis and performance is measured based on the aggregate performance during the months of June through September. As a result, fees received for the month of June could potentially be subject to adjustment or refund based on performance during the months of July through September. Based on recent changes to certain PJM program rules, we have concluded that we no longer have the ability to reliably estimate the amount of fees potentially subject to adjustment or refund until the performance period ends on September 30th of each year. Therefore, commencing in fiscal 2012, all demand response capacity revenues related to our participation in the PJM open market program are being recognized at the end of the performance period, or September 30th of each year. Because the period during which we are required to perform (June through September) is shorter than the period over which we receive payments under the program (June through May), a portion of the revenues that have been earned are recorded and accrued as unbilled revenue. As a result of the billing period not coinciding with the revenue recognition period, we had $44.9 million in unbilled revenues from PJM at December 31, 2012.

Certain of the forward capacity programs in which we participate may be deemed derivative contracts under ASC 815, *Derivatives and Hedging*, or ASC 815. In such situations, we believe we meet the scope exception under ASC 815 as a normal purchase, normal sale as that term is defined in ASC 815 and, accordingly, the arrangement is not treated as a derivative contract.

Energy event revenues are recognized when earned. Energy event revenue is deemed to be substantive and represents the culmination of a separate earnings process and is recognized when the energy event is initiated by the electric power grid operator or utility customer and we have responded under the terms of the contract or open market program.

With respect to our non-demand response revenues, which represent our EfficiencySMART, SupplySMART and other revenues, these generally represent ongoing service arrangements where the revenues are recognized ratably over the service period commencing upon delivery of the contracted service with the customer. Under certain of our arrangements, in particular certain EfficiencySMART arrangements with utilities, a portion of the fees received may be subject to adjustment or refund based on the validation of the energy savings delivered after the implementation is complete. As a result, we defer the portion of the fees that are subject to adjustment or refund until such time as the right of adjustment or refund lapses, which is generally upon completion and validation of the implementation. In addition, under certain of our other arrangements, we sell proprietary equipment to C&I customers that is utilized to provide the ongoing services that the we deliver.

Currently, this equipment has been determined to not have stand-alone value. As a result, we defer revenues associated with the equipment and we begin recognizing such revenue ratably over the expected C&I customer relationship period (generally 3 years), once the C&I customer is receiving the ongoing services from us. In addition, we capitalize the associated direct and incremental costs, which primarily represent the equipment and third-party installation costs, and recognizes such costs over the expected C&I customer relationship period.

We adopted ASC Update No. 2009-13, *Multiple-Deliverable Revenue Arrangements,* or ASU 2009-13, at the beginning of its first quarter of the fiscal year ended December 31, 2011, fiscal 2011, on a prospective basis for transactions originating or materially modified on or after January 1, 2011. The impact of adopting ASU 2009-13 was not material to our financial statements for fiscal 2011, and if it was applied in the same manner to the fiscal year ended December 31, 2010, or fiscal 2010, would not have had a material impact to revenue for fiscal 2010. The adoption of ASU 2009-13 has not had and is not expected to have a significant impact on the timing and pattern of revenue recognition due to our limited number of multiple element arrangements.

We typically determine the selling price of our services based on vendor specific objective evidence, or VSOE. Consistent with its methodology under previous accounting guidance, we determine VSOE based on its normal pricing and discounting practices for the specific service when sold on a stand-alone basis. In determining VSOE, our policy is to require a substantial majority of selling prices for a product or service to be within a reasonably narrow range. We also consider the class of customer, method of distribution, and the geographies into which its products and services are sold when determining VSOE. We typically have had VSOE for its products and services.

In certain circumstances, we are not able to establish VSOE for all deliverables in a multiple element arrangement. This may be due to the infrequent occurrence of stand-alone sales for an element, a limited sales history for new services or pricing within a broader range than permissible by our policy to establish VSOE. In those circumstances, we proceed to the alternative levels in the hierarchy of determining selling price. Third Party Evidence, or TPE, of selling price is established by evaluating largely similar and interchangeable competitor products or services in stand-alone sales to similarly situated customers. We are typically not able to determine TPE and has not used this measure since we have been unable to reliably verify standalone prices of competitive solutions. Management's best estimate of selling price, or ESP, is established in those instances where neither VSOE nor TPE are available, considering internal factors such as margin objectives, pricing practices and controls, customer segment pricing strategies and the product life cycle. Consideration is also given to market conditions such as competitor pricing information gathered from experience in customer negotiations, market research and information, recent technological trends, competitive landscape and geographies. Use of ESP is limited to a very small portion of our services, principally certain EfficiencySMART services.

We maintain a reserve for customer adjustments and allowances as a reduction in revenues. In determining our revenue reserve estimate, and in accordance with internal policy, we rely on historical data and known performance adjustments. These factors, and unanticipated changes in the economic and industry environment, could cause our reserve estimates to differ from actual results. We record a provision for estimated customer adjustments and allowances in the same period as the related revenues are recorded. These estimates are based on the specific facts and circumstances of a particular program, analysis of credit memoranda data, historical customer adjustments, and other known factors. If the data we use to calculate these estimates does not properly reflect reserve requirements, then a change in the allowances would be made in the period in which such a determination is made and revenues in that period could be affected. During the year ended December 31, 2012, we recorded a revenue reserve of $0.5 million based on our analysis. Reserve requirements in 2011 and 2010 were not material.

Business Combinations

We record tangible and intangible assets acquired and liabilities assumed in business combinations under the purchase method of accounting. Amounts paid for each acquisition are allocated to the assets acquired and liabilities assumed based on their fair values at the dates of acquisition. The fair value of identifiable intangible assets is based on detailed valuations that use information and assumptions provided by management. We estimate the fair value of contingent consideration at the time of the acquisition using all pertinent information known to us at the time to assess the probability of payment of contingent amounts. We allocate any excess purchase price over the fair value of the net tangible and intangible assets acquired and liabilities assumed to goodwill.

We use the income approach to determine the estimated fair value of identifiable intangible assets, including customer contracts, customer relationships, non-compete agreements and trade names. This approach determines fair value by estimating the after-tax cash flows attributable to an in-process project over its useful life and then discounting these after-tax cash flows back to a present value. We base our revenue assumptions on estimates of relevant market sizes, expected market growth rates and expected trends, including introductions by competitors of new services and products. We base the discount rate used to arrive at a present value as of the date of acquisition on the time value of money and market participant investment risk factors. The use of different assumptions could materially impact the purchase price allocation and our financial condition and results of operations.

Customer relationships represent established relationships with customers, which provide a ready channel for the sale of additional energy management applications, services and products. Non-compete agreements represent arrangements with certain employees that limit or prevent their ability to take employment at a competitor for a fixed period of time. Trade names represent acquired product names that we intend to continue to utilize.

We have also utilized the cost approach to determine the estimated fair value of acquired indefinite-lived intangible assets related to acquired in-process research and development given the stage of development as of the acquisition date and the lack of sufficient information regarding future expected cash flows. The cost approach calculates fair value by calculating the reproduction cost of an exact replica of the subject intangible asset. We calculate the replacement cost based on actual development costs incurred through the date of acquisition. In determining the appropriate valuation methodology, we consider, among other factors: the in-process projects' stage of completion; the complexity of the work completed as of the acquisition date; the costs already incurred; the projected costs to complete; the expected introduction date; and the estimated useful life of the technology. We believe that the estimated in-process research and development amounts so determined represent the fair value at the date of acquisition and do not exceed the amount a third party would pay for the projects.

Impairment of Intangible Assets and Goodwill

Intangible Assets

We amortize our intangible assets that have finite lives using either the straight-line method or, if reliably determinable, based on the pattern in which the economic benefit of the asset is expected to be consumed utilizing expected undiscounted future cash flows. Amortization is recorded over the estimated useful lives ranging from one to ten years. We review our intangible assets subject to amortization to determine if any adverse conditions exist or a change in circumstances has occurred that would indicate impairment or a change in the remaining useful life. If the carrying value of an asset exceeds its undiscounted cash flows, we will write-down the carrying value of the intangible asset to its fair value in the period identified. In assessing recoverability, we must make assumptions regarding estimated future cash flows and discount rates. If these estimates or related assumptions change in the future, we may be required to record impairment charges. We generally calculate fair value as the present value of estimated future cash flows to be generated by the asset using a risk-adjusted discount rate. If the estimate of an intangible asset's remaining useful life is changed, we will amortize the remaining carrying value of the intangible asset prospectively over the revised remaining useful life.

During the year ended December 31, 2012, we did not identify any adverse conditions or change in expected cash flows or useful lives of our definite-lived intangible assets that could indicate the existence of a potential impairment.

During the year ended December 31, 2011, as a result of a discontinuation of certain trade names acquired in connection with the acquisition of Energy Response in July 2011 and another immaterial acquisition that occurred in January 2011, we determined that these definite-lived intangible assets were impaired and recorded an impairment charge of $0.2 million to reduce the carrying value of these assets to zero, which was included in selling and marketing expense in the accompanying consolidated statements of operations. In addition, during the year ended December 31, 2011, as a result of the discontinuation of certain customer relationships related to a 2009 acquisition, we recorded an impairment charge of $0.3 million which was included in selling and marketing expense in the accompanying consolidated statements of operations.

During the year ended December 31, 2011, as a result of our review and realignment of our development efforts, we discontinued our efforts to complete the development of a certain in-process research and development indefinite-lived intangible asset related to our March 2010 acquisition of Zox. As a result, we recorded an impairment charge related to this indefinite-lived in-process research and development intangible asset of $0.5 million and an impairment charge related to the associated definite-lived patent intangible asset of less than $0.1 million, both of which are included in research and development expenses in the accompanying consolidated statements of operations for the year ended December 31, 2011. We had no indefinite-lived intangible assets as of December 31, 2012 or 2011, respectively.

Goodwill

In accordance with ASC 350, *Intangibles—Goodwill and Other*, or ASC 350, we test goodwill at the reporting unit level for impairment on an annual basis and between annual tests if events and circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying value. We have determined that we currently have two reporting units: (1) our consolidated Australian operations and (2) all other operations. Although our chief operating decision maker, which is our chief executive officer and certain members of our executive management team, collectively, make business decisions based on the evaluation of financial information at the entity level, certain discrete financial information is available related to our consolidated Australian operations with such discrete financial information utilized by the business unit manager to manage the consolidated Australian operations and make decisions for those operations. The consolidated Australian operations are comprised of the operations acquired in the acquisitions of Energy Response and another immaterial acquisition, as well as the operations of our subsidiary, EnerNOC Australia Pty Ltd. Events that would indicate impairment and trigger an interim impairment assessment include, but are not limited to, current economic and market conditions, including a decline in market capitalization, a significant adverse change in legal factors, business climate or operational performance of the business, and an adverse action or assessment by a regulator. Our annual impairment test date is November 30, which we refer to as the impairment date.

In performing the test, we utilize the two-step approach prescribed under ASC 350. The first step requires a comparison of the carrying value of the reporting units to the fair value of these units. We consider a number of factors to determine the fair value of a reporting unit, including an independent valuation to conduct this test. The valuation is based upon expected future discounted operating cash flows of the reporting unit as well as analysis of recent sales or offerings of similar companies. We base the discount rate used to arrive at a present value as of the date of the impairment test on our weighted average cost of capital, or WACC. If the carrying value of the reporting unit exceeds its fair value, we will perform the second step of the goodwill impairment test to measure the amount of impairment loss, if any. The second step of the goodwill impairment test compares the implied fair value of a reporting unit's goodwill to its carrying value.

In order to determine the fair value of our reporting units, we utilize both a market approach based on the quoted market price of our common stock and the number of shares outstanding and a discounted cash flow, or DCF, under the income approach. The key assumptions that drive the fair value in the DCF model are the discount rates (i.e. WACC), terminal values, growth rates, and the amount and timing of expected future cash flows. If the current worldwide financial markets and economic environment were to deteriorate, this would likely result in a higher WACC because market participants would require a higher rate of return. In the DCF, as the WACC increases, the fair value decreases. The other significant factor in the DCF is its projected financial information (i.e., amount and timing of expected future cash flows and growth rates) and if its assumptions were to be adversely impacted, this could result in a reduction of the fair value of the entity. As a result of completing the first step on the impairment date, the fair value exceeded the carrying value, and as such the second step of the impairment test was not required. To date, we have not been required to perform the second step of the impairment test. As of the impairment date and as of December 31, 2012, our market capitalization exceeded the fair value of our consolidated net assets by more than 30%. In addition, as of the impairment date, the fair value of both our consolidated Australian reporting unit and our all other operations reporting unit exceeded each of their respective carrying values by more than 50%.

The estimate of fair value requires significant judgment. Any loss resulting from an impairment test would be reflected in operating loss in our consolidated statements of operations. The annual impairment testing process is subjective and requires judgment at many points throughout the analysis. If these estimates or their related assumptions change in the future, we may be required to record impairment charges for these assets not previously recorded.

Impairment of Long-Lived Assets

We review long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances indicate that the carrying amount of assets may not be recoverable over their remaining estimated useful lives. If these assets are considered to be impaired the long-lived assets are measured for impairment at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets or liabilities. Impairment is recognized in earnings and equals the amount by which the carrying value of the assets exceeds their fair market value determined by either a quoted market price, if any, or a value determined by utilizing a DCF technique. If these assets are not impaired, but their useful lives have decreased, the remaining net book value is amortized over the revised useful life.

During the years ended December 31, 2012, 2011 and 2010, we identified impairment indicators related to certain demand response equipment as a result of the removal of such equipment from service during each of these respective years. As a result of these impairment indicators, we performed impairment tests during the years ended December 31, 2012, 2011 and 2010, and recognized impairment charges of $1.1 million, $0.6 million and $0.6 million, respectively, representing the difference between the carrying value and fair market value of the demand response equipment, which is included in cost of revenues in the accompanying consolidated statements of operations. The fair market value was determined utilizing Level 3 inputs, as defined by ASC 820, *Fair Value Measurements and Disclosures,* or ASC 820, based on the projected future cash flows discounted using the estimated market participant rate of return for this type of asset.

In connection with the decision that we made in the fourth quarter of 2012 to net settle a portion of our future contractual delivery obligations in a certain open market bidding program, we concluded that it was more likely than not that certain of our production and generation equipment utilized in connection with this demand response arrangement would be disposed or abandoned, significantly before the end of its previously estimated useful life, and that this represented a potential indicator of impairment. Accordingly, we performed an impairment test during the year ended December 31, 2012.

The applicable long-lived assets are measured for impairment at the lowest level at which identifiable cash flows are largely independent of the cash flows of other assets or liabilities. We determined that the undiscounted cash flows to be generated by the asset group over its remaining estimated useful life would not be sufficient to recover the carrying value of the asset group. We then determined the fair value of the asset group using a discounted cash flow technique based on Level 3 inputs, as defined by ASC 820, and a discount rate of 11%, which we determined represents a market rate of return for the assets being evaluated for impairment. Our estimate of the fair value of the asset group was $0.4 million compared to the carrying value of the asset group of $1.5 million. As a result, we recorded an impairment charge of $1.1 million during the year ended December 31, 2012, which is reflected in cost of revenues in the accompanying consolidated statements of operations. The impairment charge was allocated to the individual assets within the asset group on a pro-rata basis using the relative carrying amounts of those assets.

We also re-evaluated the estimated useful life of this production and generation equipment and concluded that a change in the estimated useful life was required. As a result, in December 2012, we revised the estimated useful life of the remaining net book value of the production and generation equipment totaling $0.4 million to fully depreciate these assets over the shorter of their estimated remaining useful life or the date on which our delivery obligations under this demand response arrangement are expected to cease.

During the years ended December 31, 2011 and 2010, we identified potential indicators of impairment related to certain demand response and back-up generator equipment as a result of lower than estimated demand response event performance by these assets. As a result of the potential indicators of impairment, we performed impairment tests. The applicable long-lived assets are measured for impairment at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets or liabilities. We determined that the undiscounted cash flows to be generated by the asset group over its remaining estimated useful life would not be sufficient to recover the carrying value of the asset group. We determined the fair value of the asset group using a discounted cash flow technique based on Level 3 inputs, as defined by ASC 820, and a discount rate of 11%, which we determined represents a market rate of return for the assets being evaluated for impairment. We recorded impairment charges of $0.1 million and $1.1 million during the years ended December 31, 2011 and 2010, respectively, which is reflected in cost of revenues in the accompanying consolidated statements of operations. The impairment charges were allocated to the individual assets within the asset group on a pro-rata basis using the relative carrying amounts of those assets.

Software Development Costs

We capitalize eligible costs associated with software developed or obtained for internal use. We capitalize the payroll and payroll-related costs of employees who devote time to the development of internal-use computer software in addition to applicable third-party costs. We amortize these costs on a straight-line basis over the estimated useful life of the software, which is generally two to three years. Our judgment is required in determining the point at which various projects enter the stages at which costs may be capitalized, in assessing the ongoing value and impairment of the capitalized costs, and in determining the estimated useful lives over which the costs are amortized. Internal use software development costs of $4.7 million, $3.2 million and $6.8 million for the years ended December 31, 2012, 2011 and 2010, respectively, have been capitalized. Included in the capitalized software development costs for the year ended December 31, 2012 is $0.7 million of software development costs related to the implementation of a company-wide human resource system which was put into production in June 2012 and is being amortized over a three-year useful life. During the year ended December 31, 2010, we capitalized $1.3 million of software development costs related to a company-wide enterprise resource planning system implementation project which was put into production in June 2011 and is being amortized over a five-year useful life.

The costs for the development of new software and substantial enhancements to existing software that is intended to be sold or marketed, or external use software, are expensed as incurred until technological feasibility has been established, at which time any additional costs would be capitalized. We determine that technological feasibility of external use software is established at the time a working model of software is completed. Because we believe our current process for developing external use software will be essentially completed concurrently with the establishment of technological feasibility, no costs have been capitalized to date.

Stock-Based Compensation

We recognize stock-based compensation expense associated with the fair value of stock options, restricted stock and restricted stock units issued to our employees. Determining the amount of stock-based compensation to be recorded requires us to develop estimates to be used in calculating the grant-date fair value of stock options. We use a lattice model to determine the fair value of our stock options. We consider a number of factors to determine the fair value of stock options. The model requires us to make estimates of the following assumptions:

Expected volatility—We are responsible for estimating volatility and have considered a number of factors, including third-party estimates, when estimating volatility. We currently use a combination of historical and implied volatility, which is weighted based on a number of factors.

Exit rate post-vesting—We use historical option forfeiture and expiration data to estimate the post vesting exit-rate. We believe that this historical data is currently the best estimate of the expected future post-vesting forfeiture rate.

Risk-free interest rate—The yield on zero-coupon U.S. Treasury securities for a period that is commensurate with the expected term assumption is used as the risk-free interest rate.

The fair value of stock awards where vesting is solely based on service vesting conditions is expensed ratably over the vesting period. With respect to certain awards of restricted stock where vesting contains certain performance-based vesting conditions, the fair value is expensed based on the accelerated attribution method as prescribed by ASC 718 over the vesting period. During the year ended December 31, 2012, we granted 1,023,010 shares of non-vested restricted stock to certain executives and non-executive employees that contain performance-based vesting conditions and these awards will vest in equal installments in 2013 and 2014 if the performance conditions are achieved. If the employee who received the restricted stock leaves our employment prior to the vesting date for any reason, the shares of restricted stock will be forfeited and returned to us.

In November 2011, our board of directors approved a plan to include performance-based stock awards as part of the annual non-executive bonus plan. In December 2011, 283,334 shares were issued under our Amended and Restated 2007 Employee, Director and Consultant Stock Plan with a fair value of $2.7 million and these awards will vest in equal installments in 2013 and 2014 if the performance conditions are achieved. Through December 31, 2011, we determined that no awards were probable of vesting and as a result, no stock-based compensation expense related to these awards was recorded through December 31, 2011. In March 2012, the performance conditions were modified and we determined that the modified performance conditions were probable of being achieved. As the performance-based stock awards were improbable of vesting prior to the modification of the performance conditions, the original grant date fair value is no longer used to measure compensation cost for the awards. The fair value of these awards was re-measured as of the modification date resulting in a new grant date fair value of $2.1 million after accounting for cancelled grants due to employee terminations. As these awards were probable of vesting as of March 31, 2012 and a portion of the service period had lapsed, we recorded a cumulative catch-up adjustment of stock-based compensation expense during 2012 as required by ASC 718. During the year ended December 31, 2012, there were no other changes to probabilities of existing performance-based stock awards which had a material impact on stock-based compensation expense or amounts expected to be recognized.

The amount of stock-based compensation expense recognized during a period is based on the value of the portion of the awards that are ultimately expected to vest. ASC 718 requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. Based on an analysis of historical forfeitures, we have determined a specific forfeiture rate for certain employee groups and have applied forfeiture rates ranging from 0% to 8.1% as of December 31, 2012 depending on the specific employee group. This analysis is re-evaluated periodically and the forfeiture rate is adjusted as necessary. Ultimately, the actual expense recognized over the vesting period will only be for those awards that vest.

We recognized $13.6 million, $13.5 million and $15.7 million of stock-based compensation expense for employee equity awards during the years ended December 31, 2012, 2011 and 2010, respectively.

Of the stock options outstanding at December 31, 2012, 1,265,418 options were held by our employees and directors and 9,893 options were held by non-employees. For outstanding unvested stock options related to employees as of December 31, 2012, we had $1.7 million of unrecognized stock-based compensation expense, which is expected to be recognized over a weighted average period of 1.3 years. There were no material unvested non-employee stock options as of December 31, 2012.

For non-vested restricted stock and restricted stock units subject to service-based vesting conditions outstanding as of December 31, 2012, we had $8.5 million of unrecognized stock-based compensation expense, which is expected to be recognized over a weighted average 2.5 years. For non-vested restricted stock subject to performance-based vesting conditions outstanding and that were probable of vesting as of December 31, 2012, we had $3.9 million of unrecognized stock-based compensation expense, which is expected to be recognized over a weighted average period of 1.3 years. For non-vested restricted stock subject to performance-based vesting conditions outstanding that were not probable of vesting as of December 31, 2012, we had $0.7 million of unrecognized stock-based compensation expense. If and when any additional portion of these equity awards are deemed probable to vest or awards that are deemed probable to vest become not probable, we will reflect the effect of the change in estimate in the period of change by recording a cumulative catch-up adjustment to retroactively apply the new estimate.

Accounting for Income Taxes

We use the asset and liability method for accounting for income taxes. Under this method, we determine deferred tax assets and liabilities based on the difference between financial reporting and taxes bases of our assets and liabilities. We measure deferred tax assets and liabilities using enacted tax rates and laws that will be in effect when we expect the differences to reverse.

We have incurred consolidated net losses since our inception and as a result, we had not recognized net United States deferred taxes as of December 31, 2012 or December 31, 2011. Our deferred tax liabilities primarily relate to deferred taxes associated with our acquisitions and property and equipment. Our deferred tax assets relate primarily to net operating loss carryforwards, accruals and reserves, deferred revenue and stock-based compensation. We record a valuation allowance to reduce our deferred tax assets to the amount that is more likely than not to be realized. While we have considered future taxable income and ongoing prudent and feasible tax planning strategies in assessing the need for the valuation allowance, in the event we were to determine that we would be able to realize our deferred tax assets in the future in excess of the net recorded amount, an adjustment to the deferred tax asset would increase income in the period such determination was made.

In accordance with ASC 740, *Income Taxes*, or ASC 740, we are required to evaluate uncertainty in income taxes recognized in our financial statements. ASC 740 prescribes a recognition threshold and measurement criteria for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. ASC 740 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition and defines the criteria that must be met for the benefits of a tax position to be recognized.

We had $0.4 million and $0 unrecognized tax benefits as of December 31, 2012 and 2011, respectively.

In the ordinary course of global business, there are many transactions and calculations where the ultimate tax outcome is uncertain. Judgment is required in determining our worldwide income tax provision. In our opinion, it is not required that we have a provision for income taxes for any years subject to audit. Although we believe our estimates are reasonable, no assurance can be given that the final tax outcome of matters will not be different than that which is reflected in our historical income tax provisions and accruals. In the event our assumptions are incorrect, the differences could have a material impact on our income tax provision and operating results in the period in which such determination is made.

Recent Accounting Pronouncements

Presentation of Comprehensive Income

In June 2011, the Financial Accounting Standards Board, or FASB, issued ASU No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income*, or ASU 2011-05, which requires an entity to present total comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. ASU 2011-05 does not change any of the components of comprehensive income, but it eliminates the option to present the components of other comprehensive income as part of the statement of stockholders equity. ASU 2011-05 was effective in the first quarter of 2012 and should be applied retrospectively. As such, we adopted ASU 2011-05 in 2012 and have provided a separate statement of comprehensive income (loss) in our consolidated financial statements.

In December 2011, the FASB issued ASU 2011-12, deferring certain provisions of ASU 2011-05. One of the provisions of ASU 2011-05 required entities to present reclassification adjustments out of accumulated other comprehensive income (loss) by component in both the statement in which net income is presented and the statement in which other comprehensive income (loss) is presented (for both interim and annual financial statements). This requirement is indefinitely deferred by ASU 2011-12 and will be further deliberated by the FASB at a future date. The effective date of ASU 2011-12 is the same as that for the unaffected provisions of ASU 2011-05.

Disclosures about Offsetting Assets and Liabilities

In December 2011, the FASB issued ASU No. 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities*, or ASU 2011-11. ASU 2011-11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. An entity is required to apply ASU 2011-11 for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by ASU 2011-11 retrospectively for all comparative periods presented. We do not expect that the adoption of ASU 2011-11 will have a significant, if any, impact on our consolidated financial statements.

Selected Quarterly Financial Data

The table below sets forth selected unaudited quarterly financial information. The information is derived from our unaudited consolidated financial statements and includes, in the opinion of management, all normal and recurring adjustments that management considers necessary for a fair statement of results for such periods. The operating results for any quarter are not necessarily indicative of results for any future period.

Year Ended December 31, 2012	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
	(In thousands, except per share data)			
Revenues	$ 24,450	$ 33,273	$177,947	$ 42,314
Gross profit	5,888	8,345	95,000	14,211
Operating expenses	33,958	36,111	35,689	38,074
(Loss) income from operations	(28,070)	(27,766)	59,311	(23,863)
Net (loss) income	(27,713)	(29,136)	60,348	(25,792)
Basic net (loss) income per share:	$ (1.06)	$ (1.10)	$ 2.26	$ (0.96)
Diluted net (loss) income per share:	$ (1.06)	$ (1.10)	$ 2.21	$ (0.96)

Year Ended December 31, 2011	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
	(In thousands, except per share data)			
Revenues	$ 31,762	$ 58,904	$169,183	$ 26,759
Gross profit	12,561	20,377	84,832	5,627
Operating expenses	31,132	32,869	33,861	35,072
(Loss) Income from operations	(18,571)	(12,492)	50,971	(29,445)
Net (loss) income	(19,272)	(12,973)	46,878	(28,016)
Basic net (loss) income per share:	$ (0.76)	$ (0.51)	$ 1.83	$ (1.08)
Diluted net (loss) income per share:	$ (0.76)	$ (0.51)	$ 1.77	$ (1.08)

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

Financial Instruments, Other Financial Instruments, and Derivative Commodity Instruments

ASC 825, *Financial Instruments*, requires disclosure about fair value of financial instruments. Financial instruments principally consist of cash equivalents, marketable securities, accounts receivable, and debt obligations. The fair value of these financial instruments approximates their carrying amount.

Foreign Currency Exchange Risk

Our international business is subject to risks, including, but not limited to unique economic conditions, changes in political climate, differing tax structures, other regulations and restrictions, and foreign exchange rate volatility. Accordingly, our future results could be materially adversely impacted by changes in these or other factors.

A majority of our foreign expense and sales activities are transacted in local currencies, including Australian dollars, British pounds, Canadian dollars and New Zealand dollars. Fluctuations in the foreign currency rates could affect our sales, cost of revenues and profit margins and could result in exchange losses. In addition, currency devaluations can result in a loss if we maintain deposits in a foreign currency. During each of the years ended December 31, 2012, 2011 and 2010, our sales generated outside the United States were 12%, 6% and 0%, respectively. We anticipate that sales generated outside the United States will continue to represent greater than 10% of our consolidated sales and will continue to grow in subsequent fiscal years.

The operating expenses of our international subsidiaries that are incurred in local currencies did not have a material adverse effect on our business, results of operations or financial condition for fiscal 2012. Our operating results and certain assets and liabilities that are denominated in foreign currencies are affected by changes in the relative strength of the U.S. dollar against the applicable foreign currency. Our expenses denominated in foreign currencies are positively affected when the U.S. dollar strengthens against the applicable foreign currency and adversely affected when the U.S. dollar weakens.

During the years ended December 31, 2012, 2011 and 2010, we incurred foreign exchange gains (losses) of $0.6 million, ($1.6) million and ($0.1) million, respectively. The significant increase in gains (losses) arising from transactions denominated in foreign currencies for the years ended December 31, 2012 and 2011, as compared to the same period in 2010, was due to the significant increase of foreign denominated intercompany receivables held by us from one of our Australian subsidiaries primarily as a result of the funding provided to complete the acquisition of Energy Response in July 2011 and the fluctuations of the U.S. dollar as compared to the Australian dollar from the date of acquisition through December 31, 2012. During the year ended December 31, 2012, we realized gains of $0.4 million related to transactions denominated in foreign currencies. During the years ended December 31, 2011 and 2010, there were no material realized gains (losses) incurred related to transactions denominated in foreign currencies. As of December 31, 2012, we had an intercompany receivable from our Australian subsidiary that is denominated in Australian dollars and not deemed to be of a "long-term investment" nature totaling $21.1 million at December 31, 2012 exchange rates ($20.4 million Australian).

A hypothetical 10% increase or decrease in foreign currencies in which we transact would not have a material adverse effect on our financial condition or results of operations other than the impact on the unrealized gain (loss) on the intercompany receivable held by us from our Australian subsidiary that is denominated in Australian dollars, and for which a hypothetical 10% increase or decrease in the foreign currency would result in an incremental $2.0 million gain or loss.

We currently do not have a program in place that is designed to mitigate our exposure to changes in foreign currency exchange rates. We are evaluating certain potential programs, including the use of derivative financial instruments, to reduce our exposure to foreign exchange gains and losses, and the volatility of future cash flows caused by changes in currency exchange rates. The utilization of forward foreign currency contracts would reduce, but would not eliminate, the impact of currency exchange rate movements.

Interest Rate Risk

As of December 31, 2012, we had no outstanding debt under the 2012 credit facility.

The recent market events have not required us to materially modify or change our financial risk management strategies with respect to our exposure to interest rate risk.

We manage our cash and cash equivalents portfolio considering investment opportunities and risks, tax consequences and overall financing strategies. Our investment portfolio consists primarily of cash and cash equivalents. We have, in the past, held municipal auction rate securities that have since been redeemed. As our investments are made with highly rated securities, we are not anticipating any significant impact in the short-term from a change in interest rates.

Item 8. Financial Statements and Supplementary Data

All financial statements and schedules required to be filed hereunder are included beginning on page F-1 of Appendix A hereto and incorporated into this Annual Report on Form 10-K by reference.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures.

Our principal executive officer and principal financial officer, after evaluating the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this Annual Report on Form 10-K, have concluded that, based on such evaluation, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and is accumulated and communicated to our management, including our principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act as a process designed by, or under the supervision of, our principal executive and principal financial officers and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorization of our management and directors: and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria set forth by the Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, or the COSO criteria.

Based on this assessment, management believes that, as of December 31, 2012, our internal control over financial reporting was effective at a reasonable assurance level based on these criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included elsewhere in this Annual Report on Form 10-K, has issued an attestation report on our internal control over financial reporting. That report appears below in this Item 9A under the heading "Report of Independent Registered Public Accounting Firm."

Changes in Internal Control Over Financial Reporting

No change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the fiscal quarter ended December 31, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of EnerNOC, Inc.

We have audited EnerNOC, Inc.'s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). EnerNOC, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, EnerNOC, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive (loss) income, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2012 of EnerNOC, Inc. and our report dated February 27, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Boston, Massachusetts
February 27, 2013

Item 9B. Other Information

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this Item will be contained in our definitive proxy statement for our 2013 Annual Meeting of Stockholders under the captions "Directors and Executive Officers," "Corporate Governance and Board Matters," "Corporate Code of Conduct and Ethics" and "Section 16(a) Beneficial Ownership Reporting Compliance" and is incorporated by reference herein.

Item 11. Executive Compensation

The information required by this Item will be contained in our definitive proxy statement for our 2013 Annual Meeting of Stockholders under the captions "Information About Executive and Director Compensation," "Corporate Governance and Board Matters" and "Compensation Committee Report" and is incorporated by reference herein.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this Item will be contained in our definitive proxy statement for our 2013 Annual Meeting of Stockholders under the captions "Information About Executive and Director Compensation," "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management" and is incorporated by reference herein.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item will be contained in our definitive proxy statement for our 2013 Annual Meeting of Stockholders under the captions "Certain Relationships and Related Person Transactions" and "Corporate Governance and Board Matters" and is incorporated by reference herein.

Item 14. Principal Accounting Fees and Services

The information required by this Item will be contained in our definitive proxy statement for our 2013 Annual Meeting of Stockholders under the proposal "Ratification of Appointment of Independent Registered Public Accounting Firm" and is incorporated by reference herein.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following are filed as part of this Annual Report on Form 10-K:

1. Financial Statements

The following consolidated financial statements beginning on page F-1 of Appendix A are included in this Annual Report on Form 10-K:

- Report of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets as of December 31, 2012 and 2011
- Consolidated Statements of Operations for the Years ended December 31, 2012, 2011 and 2010
- Consolidated Statements of Comprehensive (Loss) Income for the Years ended December 31, 2012, 2011 and 2010

- Consolidated Statements of Changes in Stockholders' Equity for the Years ended December 31, 2012, 2011 and 2010
- Consolidated Statements of Cash Flows for the Years ended December 31, 2012, 2011 and 2010
- Notes to the Consolidated Financial Statements

(b) Exhibits

The exhibits listed in the Exhibit Index immediately preceding the exhibits are filed with or incorporated by reference in this Annual Report on Form 10-K.

(c) Financial Statement Schedules

All other schedules have been omitted since the required information is not present, or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or the Notes thereto.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EnerNOC, Inc.

Date: February 27, 2013

By: /s/ TIMOTHY G. HEALY

Name: Timothy G. Healy
Title: Chairman of the Board and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ TIMOTHY G. HEALY Timothy G. Healy	Chairman of the Board, Chief Executive Officer and Director (principal executive officer)	February 27, 2013
/s/ KEVIN J. BLIGH Kevin J. Bligh	Chief Accounting Officer (principal financial officer and principal accounting officer)	February 27, 2013
/s/ DAVID B. BREWSTER David B. Brewster	Director and President	February 27, 2013
/s/ ARTHUR W. COVIELLO, JR. Arthur W. Coviello, Jr.	Director	February 27, 2013
/s/ RICHARD DIETER Richard Dieter	Director	February 27, 2013
/s/ TJ GLAUTHIER TJ Glauthier	Director	February 27, 2013
/s/ SUSAN F. TIERNEY Susan F. Tierney, Ph.D.	Director	February 27, 2013

APPENDIX A

EnerNOC, Inc.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of EnerNOC, Inc.

We have audited the accompanying consolidated balance sheets of EnerNOC, Inc. as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive (loss) income, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of EnerNOC, Inc. at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), EnerNOC, Inc.'s internal control over financial reporting as of December 31, 2012, based on criteria established in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Boston, Massachusetts
February 27, 2013

EnerNOC, Inc.

CONSOLIDATED BALANCE SHEETS
(in thousands, except par value and share data)

	December 31, 2012	December 31, 2011
Assets		
Current assets		
Cash and cash equivalents	$ 115,041	$ 87,297
Restricted cash	9	158
Trade accounts receivable, net of allowance for doubtful accounts of $487 and $192 at December 31, 2012 and 2011, respectively	43,250	23,977
Unbilled revenue	45,269	64,448
Capitalized incremental direct customer contract costs	10,226	5,416
Deposits	2,296	14,050
Prepaid expenses and other current assets	4,640	7,257
Total current assets	220,731	202,603
Property and equipment, net of accumulated depreciation of $67,909 and $51,400 at December 31, 2012 and 2011, respectively	32,592	36,636
Goodwill	79,505	79,213
Customer relationship intangible assets, net	21,709	26,993
Other definite-lived intangible assets, net	3,915	5,524
Capitalized incremental direct customer contract costs, long-term	3,929	3,056
Deposits and other assets	826	1,235
Total assets	$ 363,207	$355,260
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 3,976	$ 3,799
Accrued capacity payments	49,258	58,332
Accrued payroll and related expenses	13,044	11,937
Accrued expenses and other current liabilities	8,978	6,107
Accrued performance adjustments	685	6,045
Deferred revenue	28,105	10,544
Total current liabilities	104,046	96,764
Deferred acquisition consideration	533	500
Accrued acquisition contingent consideration	431	336
Deferred tax liability	4,222	2,646
Deferred revenue	11,837	6,810
Other liabilities	2,116	464
Commitments and contingencies (Note 12)	—	—
Stockholders' equity		
Undesignated preferred stock, $0.001 par value; 5,000,000 shares authorized; no shares issued	—	—
Common stock, $0.001 par value; 50,000,000 shares authorized, 29,019,923 and 27,306,548 shares issued and outstanding at December 31, 2012 and 2011, respectively	29	27
Additional paid-in capital	344,137	329,817
Accumulated other comprehensive loss	(702)	(955)
Accumulated deficit	(103,442)	(81,149)
Total stockholders' equity	240,022	247,740
Total liabilities and stockholders' equity	$ 363,207	$355,260

The accompanying notes are an integral part of these consolidated financial statements

EnerNOC, Inc.

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except share and per share data)

	Year Ended December 31,		
	2012	2011	2010
Revenues			
DemandSMART	$ 244,852	$ 259,150	$ 264,608
EfficiencySMART, SupplySMART and other	33,132	27,458	15,549
Total revenues	277,984	286,608	280,157
Cost of revenues	154,540	163,211	159,832
Gross profit	123,444	123,397	120,325
Operating expenses:			
Selling and marketing	55,963	51,907	44,029
General and administrative	71,643	66,773	54,983
Research and development	16,226	14,254	10,097
Total operating expenses	143,832	132,934	109,109
(Loss) income from operations	(20,388)	(9,537)	11,216
Other income (expense), net	1,457	(987)	(85)
Interest expense	(1,591)	(1,053)	(718)
(Loss) income before income tax	(20,522)	(11,577)	10,413
Provision for income tax	(1,771)	(1,806)	(836)
Net (loss) income	$ (22,293)	$ (13,383)	$ 9,577
(Loss) income per common share			
Basic	$ (0.84)	$ (0.52)	$ 0.39
Diluted	$ (0.84)	$ (0.52)	$ 0.37
Weighted average number of common shares outstanding			
Basic	26,551,234	25,799,494	24,611,729
Diluted	26,551,234	25,799,494	26,054,162

The accompanying notes are an integral part of these consolidated financial statements.

EnerNOC, Inc.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(in thousands)

	Year Ended December 31,		
	2012	2011	2010
Net (loss) income	$(22,293)	$(13,383)	$9,577
Foreign currency translation adjustments	253	(880)	(19)
Comprehensive (loss) income	$(22,040)	$(14,263)	$9,558

The accompanying notes are an integral part of these consolidated financial statements.

EnerNOC, Inc.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(in thousands, except share data)

	Common Stock		Additional Paid in Capital	Accumulated Other Comprehensive Loss	Accumulated Deficit	Total
	Number of Shares	Amount				
Balances as of December 31, 2009	24,233,448	$24	$272,350	$ (56)	$ (77,343)	$194,975
Issuance of common stock upon exercise of stock options	583,796	—	3,861	—	—	3,861
Issuance of restricted stock	247,900	—	—	—	—	—
Vesting of restricted stock	—	—	17			17
Vesting of restricted stock units	51,876	1	(1)	—	—	—
Cancellation of restricted stock	(22,679)	—	—	—	—	—
Issuance of common stock in satisfaction of bonuses	24,681	—	775	—	—	775
Issuance of common stock in connection with the acquisition of SmallFoot LLC and ZOX, LLC	8,758	—	260	—	—	260
Earn-out payment of common stock to South River Consulting, LLC	30,879	—	900	—	—	900
Release and retirement of escrow shares to satisfy purchase accounting obligation from Cogent	(3,592)	—	(94)	—	—	(94)
Stock based compensation expense	—	—	15,742	—	—	15,742
Tax benefit related to exercise of stock options and vesting of restricted stock and restricted stock units	—	—	132	—	—	132
Foreign currency translation loss	—	—	—	(19)	—	(19)
Net income	—	—	—	—	9,577	9,577
Balances as of December 31, 2010	25,155,067	25	293,942	(75)	(67,766)	226,126
Issuance of common stock upon exercise of stock options	310,155	—	2,034	—	—	2,034
Issuance of restricted stock	1,062,165	1	—	—	—	1
Vesting of restricted stock units	95,167	—	—	—	—	—
Cancellation of restricted stock	(72,287)	—	—	—	—	—
Issuance of common stock in satisfaction of bonuses	18,211	—	440	—	—	440
Issuance of common stock in connection with the acquisition of Global Energy Partners, Inc.	275,181	—	6,783	—	—	6,783
Issuance of common stock in connection with the acquisition of M2M Communications Corporation ("M2M")	351,665	1	8,349	—	—	8,350
Issuance of common stock in connection with the acquisition of Energy Response Holidings Pty Ltd.	156,697	—	2,491	—	—	2,491
Retirement of M2M escrow shares	(45,473)		(1,125)			(1,125)
Acquisition date fair value of shares of common stock related to deferred purchase price consideration in acquisition of M2M	—	—	3,439	—	—	3,439
Stock based compensation expense	—	—	13,464	—	—	13,464
Foreign currency translation loss	—	—	—	(880)	—	(880)
Net loss	—	—	—	—	(13,383)	(13,383)
Balances as of December 31, 2011	27,306,548	27	329,817	(955)	(81,149)	247,740
Issuance of common stock upon exercise of stock options	189,385		356			356
Issuance of restricted stock	1,581,878	2	(2)			—
Vesting of restricted stock units	92,042					—
Cancellation of restricted stock	(194,801)					—
Issuance of common stock in satisfaction of bonuses	44,871		350			350
Stock based compensation expense			13,616			13,616
Foreign currency translation gain				253		253
Net loss					(22,293)	(22,293)
Balances as of December 31, 2012	29,019,923	$29	$344,137	$(702)	$(103,442)	$240,022

The accompanying notes are an integral part of these consolidated financial statements.

EnerNOC, Inc.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2012	2011	2010
Cash flow from operating activities			
Net (loss) income	$(22,293)	$(13,383)	$ 9,577
Adjustments to reconcile net (loss) income to net cash provided by (used in) operating activities:			
Depreciation	17,977	16,187	14,414
Amortization of acquired intangible assets	7,241	5,856	1,452
Impairment of acquired intangible assets	—	1,084	—
Stock-based compensation expense	13,616	13,464	15,742
Excess tax benefit related to stock-based awards	—	—	(132)
Impairment of equipment	2,054	632	1,646
Unrealized foreign exchange transaction (gain) loss	(730)	1,401	133
Deferred taxes	1,346	1,516	469
Non-cash interest expense	377	191	26
Non-cash charges related to termination of third party agreement	—	882	—
Accretion of fair value of deferred and contingent purchase price consideration related to acquisition	128	61	—
Other, net	312	221	143
Changes in operating assets and liabilities, net of effects of acquisitions:			
Trade accounts receivable	(19,481)	2,742	(4,886)
Unbilled revenue	19,179	7,009	(32,754)
Prepaid expenses and other current assets	2,946	(85)	(79)
Capitalized incremental direct customer contract costs	(5,700)	(4,937)	(587)
Other assets	103	(3,764)	3
Other noncurrent liabilities	1,593	(176)	—
Deferred revenue	22,451	6,982	6,751
Accrued capacity payments	(9,162)	(7,369)	25,223
Accrued payroll and related expenses	1,432	1,262	2,199
Accounts payable, accrued performance adjustments, accrued expenses and other current liabilities	(2,378)	(2,139)	5,808
Net cash provided by operating activities	31,011	27,637	45,148
Cash flows from investing activities			
Payments made for acquisitions of businesses, net of cash acquired	—	(67,492)	(2,001)
Payments made for contingent consideration related to acquisitions	—	(1,500)	—
Purchases of property and equipment	(15,854)	(17,613)	(19,394)
Change in restricted cash and deposits	12,380	(8,381)	5,971
Change in long-term assets	(111)	(530)	—
Net cash used in investing activities	(3,585)	(95,516)	(15,424)
Cash flows from financing activities			
Proceeds from exercises of stock options	356	2,034	3,878
Repayment of borrowings and payments under capital leases	—	(37)	(36)
Excess tax benefit related to stock-based awards	—	—	132
Net cash provided by financing activities	356	1,997	3,974
Effects of exchange rate changes on cash and cash equivalents	(38)	(237)	(21)
Net change in cash and cash equivalents	27,744	(66,119)	33,677
Cash and cash equivalents at beginning of year	87,297	153,416	119,739
Cash and cash equivalents at end of year	$115,041	$ 87,297	$153,416
Supplemental disclosure of cash flow information			
Cash paid for interest	$ 1,204	$ 862	$ 699
Cash paid for income taxes	$ —	$ 353	$ 360
Non-cash financing and investing activities			
Issuance of common stock in connection with acquisitions	$ —	$ 16,498	$ 1,066
Issuance of common stock in satisfaction of bonuses	$ 350	$ 440	$ 775
Deferred acquisition consideration	$ —	$ 3,925	$ —
Accrued acquisition contingent consideration	$ —	$ 309	$ —

The accompanying notes are an integral part of these consolidated financial statements

EnerNOC, Inc.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(in thousands, except share and per share data)

1. Description of Business, Basis of Presentation and Summary of Significant Accounting Policies

Description of Business

EnerNOC, Inc. (the Company) is a service company that was incorporated in Delaware on June 5, 2003. The Company operates in a single segment providing energy management applications, services and products for the smart grid, which include comprehensive demand response, data-driven energy efficiency, energy price and risk management, and enterprise carbon management applications, services and products. The Company's energy management applications, services and products enable cost effective energy management strategies for its commercial, institutional and industrial end-users of energy (C&I customers) and its electric power grid operator and utility customers by reducing real-time demand for electricity, increasing energy efficiency, improving energy supply transparency, and mitigating carbon emissions. The Company uses its Network Operations Center (NOC) and comprehensive demand response application, DemandSMART, to remotely manage and reduce electricity consumption across a growing network of C&I customer sites, making demand response capacity available to electric power grid operators and utilities on demand while helping C&I customers achieve energy savings, improved financial results and environmental benefits. To date, the Company has generated revenues primarily from electric power grid operators and utilities who make recurring payments to the Company for managing demand response capacity. The Company shares these recurring payments with its C&I customers in exchange for those C&I customers reducing their power consumption when called upon.

Reclassifications and Adjustments

The Company has reclassified certain amounts in its consolidated balance sheet as of December 31, 2011 resulting in a decrease to both accounts receivable and deferred revenues of $2,012 to properly account for outstanding accounts receivable for fees that had been deferred because they were not fixed or determinable.

The Company has also reclassified certain amounts in its consolidated balance sheet as of December 31, 2011 resulting in an increase to both accounts receivable and accounts payable of $1,464 to properly account for receivables and payables under a contractual arrangement on a gross basis.

Basis of Consolidation

The consolidated financial statements of the Company include the accounts of its wholly-owned subsidiaries and have been prepared in conformity with accounting principles generally accepted in the United States (GAAP). Intercompany transactions and balances are eliminated upon consolidation.

Subsequent Events Consideration

The Company considers events or transactions that occur after the balance sheet date but prior to the issuance of the financial statements to provide additional evidence relative to certain estimates or to identify matters that require additional disclosure. Subsequent events have been evaluated as required.

Use of Estimates in Preparation of Financial Statements

The preparation of these consolidated financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. On an on-going basis, the Company evaluates its estimates, including those related to revenue recognition, allowance for doubtful accounts, valuations and purchase price allocations related to business combinations, fair value of deferred acquisition consideration, fair value of accrued acquisition contingent consideration, expected future cash flows including growth rates, discount rates, terminal values and other assumptions and estimates used to evaluate the recoverability of long-lived assets and goodwill, estimated fair values of intangible assets and goodwill, amortization methods and periods, certain accrued expenses and other related charges, stock-based compensation, contingent liabilities, tax reserves and recoverability of the Company's net deferred tax assets and related valuation allowance.

The Company bases its estimates on historical experience and various other assumptions that it believes to be reasonable under the circumstances. Changes in estimates are recorded in the period in which they become known. Actual results may differ from management's estimates if these results differ from historical experience or other assumptions prove not to be substantially accurate, even if such assumptions are reasonable when made.

The Company is subject to a number of risks similar to those of other companies of similar and different sizes both inside and outside of its industry, including, but not limited to, rapid technological changes, competition from similar energy management applications, services and products provided by larger companies, customer concentration, government regulations, market or program rule changes, protection of proprietary rights and dependence on key individuals.

Significant Accounting Policies

Restricted Cash and Cash Equivalents

Restricted cash represents cash held to secure certain insurance commitments.

Cash equivalents are highly liquid investments with insignificant interest rate risk and maturities of three months or less at the time of acquisition. Investments qualifying as cash equivalents consist of investments in money market funds, which have no withdrawal restrictions or penalties and totaled $0 and $51,841 at December 31, 2012 and 2011, respectively.

The Company held no marketable securities as of December 31, 2012 or 2011.

Disclosure of Fair Value of Financial Instruments

The Company's financial instruments mainly consist of cash and cash equivalents, restricted cash, accounts receivable, accounts payable and debt obligations. The carrying amounts of these financial instruments approximate their respective fair value due to their short-term nature.

Concentrations of Credit Risk

Financial instruments that potentially subject the Company to significant concentrations of credit risk principally consist of cash and cash equivalents, restricted cash, and billed and unbilled accounts receivable. The Company maintains its cash and cash equivalent balances with highly rated financial institutions and as a result, such funds are subject to minimal credit risk.

The Company's customers are principally located in the mid-Atlantic and northeastern regions of the United States where they are the regional electric grid operators PJM Interconnection (PJM) and ISO—New England, Inc. (ISO-NE), which are comprised of multiple utilities and were formed to control the operation of a regional power system, coordinate the supply of electricity, and establish fair and efficient markets. The Company performs ongoing credit evaluations of the financial condition of its customers and generally does not require collateral. Although the Company is directly affected by the overall financial condition of the energy industry as well as global economic conditions, the Company does not believe significant credit risk exists as of December 31, 2012. The Company generally has not experienced any material losses related to receivables from individual customers or groups of customers in the energy industry. The Company maintains an allowance for doubtful accounts based on accounts past due and historical collection experience. The Company's losses related to collection of trade receivables have consistently been within the Company's expectations. Due to these factors, the Company believes no additional credit risk beyond amounts provided for collection losses is probable.

The following table presents the Company's significant customers.

	Year Ended December 31,					
	2012		2011		2010	
	Revenues	% of Total Revenues	Revenues	% of Total Revenues	Revenues	% of Total Revenues
PJM	$111,138	40%	$153,231	53%	$167,662	60%
ISO-NE	*	*	37,469	13%	51,592	18%

* Represents less than 10% of total revenues

No other customers accounted for more than 10% of the Company's consolidated revenues for the years ended December 31, 2012, 2011 or 2010.

IMO Western Australia, Southern California Edison Company, PJM and PPL Electrical Utilities were the only customers that each comprised 10% or more of the Company's accounts receivable balance at December 31, 2012, representing 19%, 14%, 12%, and 10%, respectively, of such accounts receivable balance. PJM and Tennessee Valley Authority were the only customers that comprised 10% or more of the accounts receivable balance at December 31, 2011, at 21% and 13%, respectively.

Unbilled revenue related to PJM was $44,926 and $64,099 at December 31, 2012 and 2011, respectively. There was no significant unbilled revenue for any other customers at December 31, 2012 and 2011.

Deposits consist of funds to secure performance under certain contracts and open market bidding programs with electric power grid operator and utility customers. Deposits held by these customers were $1,888 and $14,281 at December 31, 2012 and 2011, respectively.

Property and Equipment

Property and equipment is stated at cost and depreciated using the straight-line method over the estimated useful lives of the respective assets, ranging from three to ten years. Demand response equipment is depreciated over the lesser of its useful life or the estimated C&I customer relationship period, which historically has been approximately three years. Leasehold improvements are amortized over their useful life or the original lease term, whichever is shorter. Expenditures that improve or extend the life of an asset are capitalized while repairs and maintenance expenditures are expensed as incurred.

Software Development Costs

The Company applies the provisions of Accounting Standards Codification (ASC) 350-40, *Internal-Use Software* (ASC 350-40). ASC 350-40 requires computer software costs associated with internal use software to be expensed as incurred until certain capitalization criteria are met, and it also defines which types of costs should be capitalized and which should be expensed. The Company capitalizes the payroll and payroll-related costs of employees and applicable third-party costs who devote time to the development of internal-use computer software and amortizes these costs on a straight-line basis over the estimated useful life of the software, which is generally two to five years. The Company's judgment is required in determining the point at which various projects enter the stages at which costs may be capitalized, in assessing the ongoing value and impairment of the capitalized costs, and in determining the estimated useful lives over which the costs are amortized.

Internal use software development costs of $4,653, $3,177 and $6,778 for the years ended December 31, 2012, 2011, and 2010, respectively, have been capitalized in accordance with ASC 350-40. The capitalized amounts are included as software on the consolidated balance sheets in property and equipment. Included in capitalized software development costs for the year ended December 31, 2012 is $718 of software development costs related to the implementation of a company-wide human resource system that was put into production in June 2012 and are being amortized over a three-year useful life. Included in capitalized software development costs for the year ended December 31, 2010 are $1,313 of software development costs related to a company-wide enterprise resource planning systems implementation project that was put into production in June 2011 and is being amortized over a five-year useful life. Amortization of capitalized software development costs was $4,562

$4,013 and $2,947 for the years ended December 31, 2012, 2011, and 2010, respectively. Accumulated amortization of capitalized software development costs was $15,709 and $11,147 as of December 31, 2012 and 2011, respectively.

The costs for the development of new software and substantial enhancements to existing software that is intended to be sold or marketed (external use software) are expensed as incurred until technological feasibility has been established, at which time any additional costs would be capitalized. The Company has determined that technological feasibility of external use software is established at the time a working model of software is completed. Because the Company believes its current process for developing external use software will be essentially completed concurrently with the establishment of technological feasibility, no costs have been capitalized to date.

Impairment of Property and Equipment

The Company reviews property and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of assets may not be recoverable over its remaining estimated useful life. If these assets are considered to be impaired, the long-lived assets are measured for impairment at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets or liabilities. Impairment is recognized in earnings and equals the amount by which the carrying value of the assets exceeds their fair market value determined by either a quoted market price, if any, or a value determined by utilizing a discounted cash flow (DCF) technique. If these assets are not impaired, but their useful lives have decreased, the remaining net book value is amortized over the revised useful life.

In connection with the decision that the Company made in the fourth quarter of 2012 to net settle a portion of its future contractual delivery obligations in a certain open market bidding program, the Company concluded that it was more likely than not that certain of its production and generation equipment utilized in connection with this program would be disposed or abandoned before the end of its previously estimated useful life and that this represented a potential indicator of impairment. Accordingly, the Company performed an impairment test during the three months ended December 31, 2012.

The applicable long-lived assets were measured for impairment at the lowest level at which identifiable cash flows are largely independent of the cash flows of other assets or liabilities. The Company determined that the undiscounted cash flows to be generated by the asset group over its remaining estimated useful life would not be sufficient to recover the carrying value of the asset group. The Company then determined the fair value of the asset group using a discounted cash flow technique based on Level 3 inputs, as defined by ASC 820, *Fair Value Measurements and Disclosures* (ASC 820), and a discount rate of 11%, which the Company determined represents a market rate of return for the assets being evaluated for impairment. The Company's estimate of the fair value of the asset group was $412 compared to the carrying value of the asset group of $1,482. As a result, the Company recorded an impairment charge of $1,070 during the three months ended December 31, 2012, which is reflected in cost of revenues in the accompanying consolidated statements of operations. The impairment charge was allocated to the individual assets within the asset group on a pro-rata basis using the relative carrying amounts of those assets.

The Company also re-evaluated the estimated useful life of this production and generation equipment and concluded that a change in the estimated useful life was required. As a result, commencing in December 2012, the Company revised the estimated useful life of the remaining net book value of the production and generation equipment totaling $412 to fully depreciate these assets over the shorter of their remaining useful life or the date on which the Company's delivery obligations under this program are expected to cease. Refer to Note 12 for further discussion related to net settlement of the Company's obligation under this program.

During the years ended December 31, 2012, 2011 and 2010, the Company identified impairment indicators related to certain demand response equipment as a result of the removal of such equipment from service during each of these respective years. As a result of these impairment indicators, the Company performed impairment tests during the years ended December 31, 2012, 2011 and 2010, and recognized impairment charges of $984,

$566, and $552, respectively, representing the difference between the carrying value and fair market value of the demand response equipment, which is included in cost of revenues in the accompanying consolidated statements of operations. The fair market value was determined utilizing Level 3 inputs, as defined by ASC 820, based on the projected future cash flows discounted using the estimated market participant rate of return for this type of asset.

During the years ended December 31, 2011 and 2010, the Company identified potential indicators of impairment related to certain demand response and back-up generator equipment as a result of lower than estimated demand response event performance by these assets. As a result of the potential indicators of impairment, the Company performed impairment tests. The applicable long-lived assets are measured for impairment at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets or liabilities. The Company determined that the undiscounted cash flows to be generated by the asset group over its remaining estimated useful life would not be sufficient to recover the carrying value of the asset group. The Company determined the fair value of the asset group using a discounted cash flow technique based on Level 3 inputs, as defined by ASC 820, and a discount rate of 11%, which the Company determined represents a market rate of return for the assets being evaluated for impairment. The Company recorded impairment charges of $66 and $1,094 during the years ended December 31, 2011 and 2010, respectively, which are reflected in cost of revenues in the accompanying consolidated statements of operations. The impairment charges were allocated to the individual assets within the asset group on a pro-rata basis using the relative carrying amounts of those assets.

Business Combinations

The Company records tangible and intangible assets acquired and liabilities assumed in business combinations under the purchase method of accounting. Amounts paid for each acquisition are allocated to the assets acquired and liabilities assumed based on their fair values at the dates of acquisition. The fair value of identifiable intangible assets is based on detailed valuations that use information and assumptions provided by the Company. The Company estimates the fair value of contingent consideration at the time of the acquisition using all pertinent information known to the Company at the time to assess the probability of payment of contingent amounts. The Company allocates any excess purchase price over the fair value of the net tangible and intangible assets acquired and liabilities assumed to goodwill.

The Company primarily uses the income approach to determine the estimated fair value of identifiable intangible assets, including customer relationships, non-compete agreements and trade names. This approach determines fair value by estimating the after-tax cash flows attributable to an in-process project over its useful life and then discounting these after-tax cash flows back to a present value. The Company bases its revenue assumptions on estimates of relevant market sizes, expected market growth rates and expected trends, including introductions by competitors of new energy management applications, services and products. The Company bases the discount rate used to arrive at a present value as of the date of acquisition on the time value of money and market participant investment risk factors. The use of different assumptions could materially impact the purchase price allocation and the Company's financial condition and results of operations.

The Company utilized the cost approach to determine the estimated fair value of acquired indefinite-lived intangible assets related to acquired in-process research and development given the stage of development as of the acquisition date and the lack of sufficient information regarding future expected cash flows. The cost approach calculates fair value by calculating the reproduction cost of an exact replica of the subject intangible asset. The Company calculates the replacement cost based on actual development costs incurred through the date of acquisition. In determining the appropriate valuation methodology, the Company considers, among other factors: the in-process projects' stage of completion; the complexity of the work completed as of the acquisition date; the costs already incurred; the projected costs to complete; the expected introduction date; and the estimated useful life of the technology. The Company believes that the estimated in-process research and development amounts so determined represented the fair value at the date of acquisition and did not exceed the amount a third party would pay for the projects.

Impairment of Intangible Assets and Goodwill

Definite-Lived and Indefinite-Lived Intangible Assets

The Company amortizes its intangible assets that have finite lives using either the straight-line method or, if reliably determinable, based on the pattern in which the economic benefit of the asset is expected to be consumed utilizing expected undiscounted future cash flows. Amortization is recorded over the estimated useful lives ranging from one to ten years. The Company reviews its intangible assets subject to amortization to determine if any adverse conditions exist or a change in circumstances has occurred that would indicate impairment or a change in the remaining useful life. If the carrying value of an asset exceeds its undiscounted cash flows, the Company will write-down the carrying value of the intangible asset to its fair value in the period identified. In assessing recoverability, the Company must make assumptions regarding estimated future cash flows and discount rates. If these estimates or related assumptions change in the future, the Company may be required to record impairment charges. The Company generally calculates fair value as the present value of estimated future cash flows to be generated by the asset using a risk-adjusted discount rate. If the estimate of an intangible asset's remaining useful life is changed, the Company will amortize the remaining carrying value of the intangible asset prospectively over the revised remaining useful life.

During the year ended December 31, 2012, the Company did not identify any adverse conditions or change in expected cash flows or useful lives of its definite-lived intangible assets that could indicate the existence of a potential impairment.

During the year ended December 31, 2011, as a result of a discontinuation of certain trade names acquired in connection with the acquisition of Energy Response Holdings Pty Ltd (Energy Response) in July 2011 and another immaterial acquisition that occurred in January 2011, the Company determined that these definite-lived intangible assets were impaired and recorded an impairment charge of $241 to reduce the carrying value of these assets to zero, which was included in selling and marketing expense in the accompanying consolidated statements of operations. In addition, during the year ended December 31, 2011, as a result of the discontinuation of certain customer relationships related to a 2009 acquisition, the Company recorded an impairment charge of $296, which was included in selling and marketing expense in the accompanying consolidated statements of operations.

During the year ended December 31, 2011, as a result of the Company's review and realignment of the Company's development efforts, the Company discontinued its efforts to complete the development of a certain in-process research and development indefinite-lived intangible asset related to the Company's March 2010 acquisition of Zox, LLC (Zox). As a result, the Company recorded an impairment charge of $530 related to this indefinite-lived in-process research and development intangible asset, and an impairment charge of $17 related to the associated definite-lived patent intangible asset, both of which are included in research and development expense in the accompanying consolidated statements of operations for the year ended December 31, 2011. The Company had no indefinite-lived intangible assets as of December 31, 2012 or 2011, respectively.

The following table provides the gross carrying amount and related accumulated amortization of the Company's definite-lived intangible assets as of December 31, 2012 and December 31, 2011:

	Weighted Average Amortization Period (in years)	As of December 31, 2012		As of December 31, 2011	
		Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Customer relationships	4.10	$32,667	$(10,958)	$32,279	$(5,286)
Customer contracts	4.24	4,218	(2,420)	4,217	(2,007)
Employment agreements and non-compete agreements	1.23	1,728	(1,115)	1,726	(707)
Software	—	120	(120)	120	(103)
Developed Technology	1.81	2,300	(1,161)	2,297	(517)
Trade name	1.14	575	(340)	575	(225)
Patents	7.16	180	(50)	180	(32)
Total other definite-lived intangible assets		9,121	(5,206)	9,115	(3,591)
Total		$41,788	$(16,164)	$41,394	$(8,877)

The change in the gross carrying amount of definite-lived intangible assets from December 31, 2011 to December 31, 2012 was due to foreign currency translation adjustments that resulted from a weaker U.S. dollar. Amortization expense related to definite-lived intangible assets amounted to $7,241, $5,856 and $1, 452 for years ended December 31, 2012, 2011 and 2010, respectively. Amortization expense for developed technology, which was acquired as part of the Company's acquisitions, was $644 and $517 for the years ended December 31, 2012 and 2011, respectively, and is included in cost of revenues in the accompanying consolidated statements of operations. Amortization expense for all other intangible assets is included as a component of operating expenses in the accompanying consolidated statements of operations. The intangible asset lives range from approximately one to ten years and the weighted average remaining life was approximately 3.8 years at December 31, 2012. Estimated amortization expense is expected to be approximately $7,273, $6,638, $4,681, $4,096 and $2,936 for 2013, 2014, 2015, 2016 and 2017, respectively.

Goodwill

In accordance with ASC 350, *Intangibles—Goodwill and Other* (ASC 350), the Company tests goodwill at the reporting unit level for impairment on an annual basis and between annual tests if events and circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying value. The Company has determined that it currently has 2 reporting units: (1) the consolidated Australian operations and (2) all other operations. Although the Company's chief operating decision maker, which is the Company's chief executive officer and certain members of the Company's executive management team, collectively, make business decisions based on the evaluation of financial information at the entity level, certain discrete financial information is available related to the Company's consolidated Australian operations with such discrete financial information utilized by the business unit manager to manage the consolidated Australian operations and make decisions for those operations. The consolidated Australian operations are comprised primarily of the operations acquired in the fiscal 2011 acquisitions of Energy Response and EnerNOC Australia Pty Ltd. Events that would indicate impairment and trigger an interim impairment assessment include, but are not limited to, current economic and market conditions, including a decline in market capitalization, a significant adverse change in legal factors, business climate or operational performance of the business, and an adverse action or assessment by a regulator. The Company's annual impairment test date is November 30 (Impairment Date).

In performing the test, the Company utilizes the two-step approach prescribed under ASC 350. The first step requires a comparison of the carrying value of the reporting units to the fair value of these units. The Company considers a number of factors to determine the fair value of a reporting unit, including an independent valuation to conduct this test. The valuation is based upon expected future discounted operating cash flows of the reporting unit as well as analysis of recent sales or offerings of similar companies. The Company bases the discount rate used to arrive at a present value as of the date of the impairment test on its weighted average cost of capital (WACC). If the carrying value of the reporting unit exceeds its fair value, the Company will perform the second step of the goodwill impairment test to measure the amount of impairment loss, if any. The second step of the goodwill impairment test compares the implied fair value of a reporting unit's goodwill to its carrying value.

In order to determine the fair value of the reporting units, the Company utilizes both a market approach based on the quoted market price of its common stock and the number of shares outstanding and a DCF under the income approach. The key assumptions that drive the fair value in the DCF model are the discount rates (i.e., WACC), terminal values, growth rates, and the amount and timing of expected future cash flows. If the current worldwide financial markets and economic environment were to deteriorate, this would likely result in a higher WACC because market participants would require a higher rate of return. In the DCF, as the WACC increases, the fair value decreases. The other significant factor in the DCF is its projected financial information (i.e., amount and timing of expected future cash flows and growth rates) and if its assumptions were to be adversely impacted this could result in a reduction of the fair value of the entity. As a result of completing the first step of the impairment assessment on the Impairment Date, the fair value exceeded the carrying value, and as such, the second step was not required. To date, the Company has not been required to perform the second step of the impairment test. As of both the Impairment Date and December 31, 2012, the Company's market capitalization exceeded the fair value of its consolidated net assets by more than 30%. In addition, as of the Impairment Date, the fair value of both the Company's consolidated Australian reporting unit and the Company's all other operations reporting unit exceeded each of their respective carrying values by more than 50%.

The estimate of fair value requires significant judgment. Any loss resulting from an impairment test would be reflected in operating loss in the Company's consolidated statements of operations. The annual impairment testing process is subjective and requires judgment at many points throughout the analysis. If these estimates or their related assumptions change in the future, the Company may be required to record impairment charges for these assets not previously recorded.

The following table shows the change of the carrying amount of goodwill from December 31, 2011 to December 31, 2012:

Balance at December 31, 2011	$79,213
Purchase price adjustment related to Energy Response (1)	34
Foreign currency translation impact	258
Balance at December 31, 2012	$79,505

(1) Based on new information gathered during the three months ended March 31, 2012 about facts and circumstances that existed as of the acquisition date related to a pre-acquisition liability of Energy Response, the Company reflected this additional liability as part of its purchase accounting, resulting in a decrease of net tangible assets acquired and a corresponding increase to goodwill.

Income Taxes

The Company uses the asset and liability method for accounting for income taxes. Under this method, the Company determines deferred tax assets and liabilities based on the difference between financial reporting and tax bases of its assets and liabilities. The Company records its deferred tax assets and liabilities using enacted tax rates and laws that will be in effect when the Company expects the differences to reverse.

The Company has accumulated consolidated net losses since its inception and, as a result, the Company has not recognized net United States deferred tax assets as of December 31, 2012 or 2011. The Company's deferred tax liabilities primarily relate to deferred taxes associated with the Company's acquisitions and depreciation of property and equipment. The Company's deferred tax assets relate primarily to net operating loss carryforwards, accruals and reserves, deferred revenue, and stock-based compensation. The Company records a valuation allowance to reduce its deferred tax assets to the amount that is more likely than not expected to be realized.

While the Company has considered future taxable income and ongoing prudent and feasible tax planning strategies in assessing the need for the valuation allowance, in the event the Company were to determine that it would be able to realize its deferred tax assets in the future in excess of the net recorded amount, an adjustment to the deferred tax asset would increase income in the period such determination was made.

ASC 740, *Income Taxes* (ASC 740), prescribes a recognition threshold and measurement criteria for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. ASC 740 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition and defines the criteria that must be met for the benefits of a tax position to be recognized.

The Company had $399 and $0 unrecognized tax benefits as of December 31, 2012 and 2011, respectively.

In the ordinary course of global business, there are many transactions and calculations in which the ultimate tax outcome is uncertain. Judgment is required in determining the Company's worldwide income tax provision. In the Company's opinion, it is not required that it have a provision for income taxes for any years subject to audit. Although the Company believes its estimates are reasonable, no assurance can be given that the final tax outcome of matters will not be different than that which is reflected in the Company's historical income tax provisions and accruals. In the event the Company's assumptions are incorrect, the differences could have a material impact on its income tax provision and operating results in the period in which such determination is made.

Industry Segment Information

The Company views its operations and manages its business as one operating segment. Operating segments are defined as components of an enterprise about which separate financial information is available that is evaluated regularly by the chief operating decision maker, or decision making group, in making decisions on how to allocate resources and assess performance. The Company's chief operating decision maker is considered to be the team comprised of the chief executive officer and certain members of the executive management team.

The Company operates in the major geographic areas noted in the chart below. The "All other" designation includes Australia, Canada, New Zealand and the United Kingdom. Revenues are based upon customer location and internationally totaled $34,211, $16,999 and $253 for the years ended December 31, 2012, 2011 and 2010, respectively. No individual foreign country accounted for more than 10% of the Company's total revenues for the years ended December 31, 2012, 2011 and 2010, respectively.

Revenues by geography as a percentage of total revenues are as follows:

	Year Ended December 31,		
	2012	2011	2010
United States	88%	94%	100%
All other	12	6	—
Total	100%	100%	100%

As of December 31, 2012 and 2011, the long-lived tangible assets related to the Company's international subsidiaries were not material.

Revenue Recognition

The Company recognizes revenues in accordance with Accounting Standards Codification 605, *Revenue Recognition* (ASC 605). In all of the Company's arrangements, it does not recognize any revenues until it can determine that persuasive evidence of an arrangement exists, delivery has occurred, the fee is fixed or determinable, and it deems collection to be reasonably assured. In making these judgments, the Company evaluates the following criteria:

- *Evidence of an arrangement.* The Company considers a definitive agreement signed by the customer and the Company or an arrangement enforceable under the rules of an open market bidding program to be representative of persuasive evidence of an arrangement.

- *Delivery has occurred.* The Company considers delivery to have occurred when service has been delivered to the customer and no significant post-delivery obligations exist. In instances where customer acceptance is required, delivery is deemed to have occurred when customer acceptance has been achieved.
- *Fees are fixed or determinable.* The Company considers the fee to be fixed or determinable unless the fee is subject to refund or adjustment or is not payable within normal payment terms. If the fee is subject to refund or adjustment and the Company cannot reliably estimate this amount, the Company recognizes revenues when the right to a refund or adjustment lapses. If the Company offers payment terms significantly in excess of its normal terms, it recognizes revenues as the amounts become due and payable or upon the receipt of cash.
- *Collection is reasonably assured.* The Company conducts a credit review at the inception of an arrangement to determine the creditworthiness of the customer. Collection is reasonably assured if, based upon evaluation, the Company expects that the customer will be able to pay amounts under the arrangement as payments become due. If the Company determines that collection is not reasonably assured, revenues are deferred and recognized upon the receipt of cash.

The Company enters into contracts and open market bidding programs with utilities and electric power grid operators to provide demand response applications and services. Demand response revenues consist of two elements: revenue earned based on the Company's ability to deliver committed capacity to its electric power grid operator and utility customers, which the Company refers to as capacity revenue; and revenue earned based on additional payments made to the Company for the amount of energy usage actually curtailed from the grid during a demand response event, which the Company refers to as energy event revenue.

The Company recognizes demand response revenue when it has provided verification to the electric power grid operator or utility of its ability to deliver the committed capacity which entitles the Company to payments under the contract or open market program. Committed capacity is generally verified through the results of an actual demand response event or a measurement and verification test. Once the capacity amount has been verified, the revenue is recognized and future revenue becomes fixed or determinable and is recognized monthly until the next demand response event or test. In subsequent verification events, if the Company's verified capacity is below the previously verified amount, the electric power grid operator or utility customer will reduce future payments based on the adjusted verified capacity amounts. Ongoing demand response revenue recognized between demand response events or tests that are not subject to penalty or customer refund are recognized in revenue. If the revenue is subject to refund and the amount of refund cannot be reliably estimated, the revenue is deferred until the right of refund lapses.

The Company has evaluated the factors within ASC 605 regarding gross versus net revenue reporting for its demand response revenues and its payments to C&I customers. Based on the evaluation of the factors within ASC 605, the Company has determined that all of the applicable indicators of gross revenue reporting were met. The applicable indicators of gross revenue reporting included, but were not limited to, the following:

- The Company is the primary obligor in its arrangements with electric power grid operators and utility customers because the Company provides its demand response services directly to electric power grid operators and utilities under long-term contracts or pursuant to open market programs and contracts separately with C&I customers to deliver such services. The Company manages all interactions with the electric power grid operators and utilities, while C&I customers do not interact with the electric power grid operators and utilities. In addition, the Company assumes the entire performance risk under its arrangements with electric power grid operators and utility customers, including the posting of financial assurance to assure timely delivery of committed capacity with no corresponding financial assurance received from its C&I customers. In the event of a shortfall in delivered committed capacity, the Company is responsible for all penalties assessed by the electric power grid operators and utilities without regard for any recourse the Company may have with its C&I customers.
- The Company has latitude in establishing pricing, as the pricing under its arrangements with electric power grid operators and utilities is negotiated through a contract proposal and contracting process or determined through a capacity auction. The Company then separately negotiates payment to C&I customers and has complete discretion in the contracting process with the C&I customers.

- The Company has complete discretion in determining which suppliers (C&I customers) will provide the demand response services, provided that the C&I customer is located in the same region as the applicable electric power grid operator or utility.
- The Company is involved in both the determination of service specifications and performs part of the services, including the installation of metering and other equipment for the monitoring, data gathering and measurement of performance, as well as, in certain circumstances, the remote control of C&I customer loads.

As a result, the Company determined that it earns revenue (as a principal) from the delivery of demand response services to electric power grid operators and utility customers and records the amounts billed to the electric power grid operators and utility customers as gross demand response revenues and the amounts paid to C&I customers as cost of revenues.

Commencing in fiscal 2012, all demand response capacity revenues related to the Company's participation in the PJM open market program are being recognized at the end of the four-month delivery period of June through September, or during the three month period ended September 30th of each year. Because the period during which the Company is required to perform (June through September) is shorter than the period over which payments are received under the program (June through May), a portion of the revenues that have been earned are recorded and accrued as unbilled revenue. Substantially all revenues related to the current PJM open market program year were recognized during the three month period ended September 30, 2012, and as a result of the billing period not coinciding with the revenue recognition period, the Company had $44,926 in unbilled revenues from PJM at December 31, 2012.

As a result of contractual amendments entered into during the year ended December 31, 2011 to amend certain refund provisions included in one of the Company's contracts with a utility customer, the Company concluded that it could reliably estimate the fees potentially subject to refund and therefore, the fees were fixed or determinable. As a result, during the year ended December 31, 2011 the Company recognized as revenues $5,319 of fees that had been previously deferred. As of December 31, 2012 and 2011, there were no deferred revenues related to this contractual arrangement.

Energy event revenues are recognized when earned. Energy event revenue is deemed to be substantive and represents the culmination of a separate earnings process and is recognized when the energy event is initiated by the electric power grid operator or utility customer and the Company has responded under the terms of the contract or open market program.

Certain of the forward capacity programs in which the Company participates may be deemed derivative contracts under ASC 815, *Derivatives and Hedging* (ASC 815). In such situations, the Company believes it meets the scope exception under ASC 815 as a normal purchase, normal sale as that term is defined in ASC 815 and, accordingly, the arrangement is not treated as a derivative contract.

With respect to the Company's non-demand response revenues, which represent the Company's EfficiencySMART, SupplySMART and other revenues, these generally represent ongoing service arrangements where the revenues are recognized ratably over the service period commencing upon delivery of the contracted service with the customer. Under certain of the Company's arrangements, in particular certain EfficiencySMART arrangements with utilities, a portion of the fees received may be subject to adjustment or refund based on the validation of the energy savings delivered after the implementation is complete. As a result, the Company defers the portion of the fees that are subject to adjustment or refund until such time as the right of adjustment or refund lapses, which is generally upon completion and validation of the implementation. In addition, under certain other of the Company's arrangements, the Company sells proprietary equipment to C&I customers that is utilized to provide the ongoing services that the Company delivers. Currently, this equipment has been determined to not have stand-alone value. As a result, the Company defers revenues associated with the equipment and the Company begins recognizing such revenue ratably over the expected C&I customer relationship period (generally 3 years), once the C&I customer is receiving the ongoing services from the Company. In addition, the Company capitalizes the associated direct and incremental costs, which primarily represent the equipment and third-party installation costs, and recognizes such costs over the expected C&I customer relationship period.

The Company adopted ASC Update No. 2009-13, *Multiple-Deliverable Revenue Arrangements* (ASU 2009-13) at the beginning of its first quarter of the fiscal year ended December 31, 2011 (fiscal 2011) on a prospective basis for transactions originating or materially modified on or after January 1, 2011. The impact of adopting ASU 2009-13 was not material to the Company's financial statements fiscal 2011, and if it was applied in the same manner to the fiscal year ended December 31, 2010 (fiscal 2010) would not have had a material impact to revenue for fiscal 2010. The adoption of ASU 2009-13 has not had and is not expected to have a significant impact on the timing and pattern of revenue recognition due to the Company's limited number of multiple element arrangements.

The Company typically determines the selling price of its services based on vendor specific objective evidence (VSOE). Consistent with its methodology under previous accounting guidance, the Company determines VSOE based on its normal pricing and discounting practices for the specific service when sold on a stand-alone basis. In determining VSOE, the Company's policy is to require a substantial majority of selling prices for a product or service to be within a reasonably narrow range. The Company also considers the class of customer, method of distribution, and the geographies into which its products and services are sold when determining VSOE. The Company typically has had VSOE for its products and services.

In certain circumstances, the Company is not able to establish VSOE for all deliverables in a multiple element arrangement. This may be due to the infrequent occurrence of stand-alone sales for an element, a limited sales history for new services or pricing within a broader range than permissible by the Company's policy to establish VSOE. In those circumstances, the Company proceeds to the alternative levels in the hierarchy of determining selling price. Third Party Evidence (TPE) of selling price is established by evaluating largely similar and interchangeable competitor products or services in stand-alone sales to similarly situated customers. The Company is typically not able to determine TPE and has not used this measure since the Company has been unable to reliably verify standalone prices of competitive solutions. Management's best estimate of selling price (ESP) is established in those instances where neither VSOE nor TPE are available, considering internal factors such as margin objectives, pricing practices and controls, customer segment pricing strategies and the product life cycle. Consideration is also given to market conditions such as competitor pricing information gathered from experience in customer negotiations, market research and information, recent technological trends, competitive landscape and geographies. Use of ESP is limited to a very small portion of the Company's services, principally certain EfficiencySMART services.

The Company maintains a reserve for customer adjustments and allowances as a reduction in revenues. In determining the Company's revenue reserve estimate, and in accordance with internal policy, the Company relies on historical data and known performance adjustments. These factors, and unanticipated changes in the economic and industry environment, could cause the Company's reserve estimates to differ from actual results. The Company records a provision for estimated customer adjustments and allowances in the same period as the related revenues are recorded. These estimates are based on the specific facts and circumstances of a particular program, analysis of credit memo data, historical customer adjustments, and other known factors. If the data the Company uses to calculate these estimates does not properly reflect reserve requirements, then a change in the allowances would be made in the period in which such a determination is made and revenues in that period could be affected. During the year ended December 31, 2012, the Company recorded a revenue reserve of $524 based on its analysis. Reserve requirements in 2011 and 2010 were not material.

Cost of Revenues

Cost of revenues for demand response services consists primarily of amounts owed to the Company's C&I customers for their participation in the Company's demand response network and are generally recognized over the same performance period as the corresponding revenue. The Company enters into contracts with C&I customers under which it delivers recurring cash payments to them for the capacity they commit to make available on demand. The Company also generally makes an additional payment when a C&I customer reduces consumption of energy from the electric power grid during a demand response event. The equipment and installation costs for devices located at C&I customer sites are capitalized and depreciated over the lesser of the remaining estimated customer relationship period or the estimated useful life of the equipment, and this depreciation is reflected in cost of revenues. The Company also includes in cost of revenues the amortization of acquired developed technology, amortization of capitalized internal-use software costs related to DemandSMART application, the monthly telecommunications and data costs incurred as a result of being connected to C&I customer sites, and the internal payroll and related costs allocated to a C&I customer site. Cost of revenues for the EfficiencySMART and SupplySMART applications and services and for the sale, installation and ongoing services of the Company's wireless technology solutions include amortization of capitalized internal-use software costs related to those applications and services, third party services, equipment costs, equipment depreciation, and the wages and associated benefits that the Company pays to its project managers for the performance of their services.

Research and Development Expenses

Research and development expenses consist primarily of (a) salaries and related personnel costs, including costs associated with share-based payment awards, related to the Company's research and development organization, (b) payments to suppliers for design and consulting services, (c) costs relating to the design and development of new energy management applications, services and products and enhancement of existing energy management applications, services and products, (d) quality assurance and testing and (e) other related overhead. Costs incurred in research and development are expensed as incurred.

Stock-Based Compensation

The Company accounts for stock-based compensation in accordance with ASC 718, *Stock Compensation* (ASC 718). As such, all share-based payments to employees, including grants of stock options, restricted stock and restricted stock units, are recognized in the statement of operations based on their fair values as of the date of grant. As of December 31, 2012, the Company had one stock-based compensation plan, which is more fully described in Note 9 below. Generally, the Company grants stock-based awards with exercise prices equal to the estimated fair value of its common stock; however, to the extent that the deemed fair value of the common stock exceeded the exercise or purchase price of stock-based awards granted to employees on the date of grant, the Company amortizes the expense over the vesting schedule of the awards, generally four years.

For stock options granted prior to January 1, 2009, the fair value of each option was estimated at the date of grant using a Black-Scholes option-pricing model. For stock options granted on or after January 1, 2009, the fair value of each option has been and will be estimated on the date of grant using a lattice valuation model. The lattice model considers characteristics of fair value option pricing that are not available under the Black-Scholes model. Similar to the Black-Scholes model, the lattice model takes into account variables such as expected volatility, dividend yield rate, and risk free interest rate. However, in addition, the lattice model considers the probability that the option will be exercised prior to the end of its contractual life and the probability of termination or retirement of the option holder in computing the value of the option. For these reasons, the Company believes that the lattice model provides a fair value that is more representative of actual experience and future expected experience than that value calculated using the Black-Scholes model. Stock-based compensation for the years ended December 31, 2012, 2011 and 2010 was $13,616, $13,464 and $15,742, respectively. See Note 9 for additional information regarding stock-based compensation.

Foreign Currency Translation

The financial statements of the Company's international subsidiaries are translated in accordance with ASC 830, *Foreign Currency Matters* (ASC 830), into the Company's reporting currency, which is the United States dollar. The functional currencies of the Company's subsidiaries in Canada, the United Kingdom, Australia and New Zealand are the Canadian dollar, the British pound, the Australian dollar and the New Zealand dollar, respectively. Assets and liabilities are translated to the United States dollar from the local functional currency at the exchange rate in effect at each balance sheet date. Before translation, the Company re-measures foreign currency denominated assets and liabilities, including certain inter-company accounts receivable and payable that have been determined to not be of a "long-term investment" nature, as defined by ASC 830, into the functional currency of the respective entity, resulting in unrealized gains or losses recorded in the consolidated statements of operations. Revenues and expenses are translated using average exchange rates during the respective periods.

Foreign currency translation adjustments are recorded as a component of other comprehensive income and included in accumulated other comprehensive loss within stockholders' equity. Gains (losses) arising from transactions denominated in foreign currencies and the remeasurement of certain intercompany receivables and payables are included in other (expense) income, net on the consolidated statements of operations and were $1,106, ($1,580), and ($133) for the years ended December 31, 2012, 2011 and 2010, respectively. The significant increase in gains (losses) arising from transactions denominated in foreign currencies since the year ended December 31, 2010 is due to the significant increase of foreign denominated intercompany receivables held by the Company from one of its Australian subsidiaries primarily as a result of the funding provided to complete the acquisition of Energy Response (see Note 2) and the significant fluctuations of the United States dollar as compared to the Australian dollar during the years ended December 31, 2012 and 2011. During the year ended December 31, 2012, the Company settled $17,468 ($16,400 Australian) of the intercompany receivable from the Company's Australian subsidiary resulting in a realized gain of $494. During the years ended December 31, 2012 and 2011, there were no material realized gains or losses incurred related to transactions denominated in foreign currencies. As of December 31, 2012, the Company had an intercompany receivable from its Australian subsidiary that is denominated in Australia dollars and not deemed to be of a "long-term investment" nature totaling $21,153 at December 31, 2012 exchange rates ($20,391 Australian).). Subsequent to December 31, 2012, the Company settled $2,518 ($2,421 Australian) of the intercompany receivable from the Company's Australian subsidiary.

In addition, a portion of the funding provided by the Company to one of its Australian subsidiaries to complete the acquisition of Energy Response (see Note 2) was deemed to be of a "long-term investment" nature and therefore, the resulting translation adjustments are being recorded as a component of stockholders' equity within accumulated other comprehensive loss. As of December 31, 2012, the intercompany funding that is denominated in Australia dollars and deemed to be of a "long-term investment" nature totaled $21,125 ($20,364 Australian).

Comprehensive (Loss) Income

Comprehensive (loss) income is defined as the change in equity of a business enterprise during a period resulting from transactions and other events and circumstances from non-owner sources. Comprehensive (loss) income is composed of net (loss) income and foreign currency translation adjustments. As of December 31, 2012 and 2011, accumulated other comprehensive loss was comprised solely of cumulative foreign currency translation adjustments. The Company presents its components of other comprehensive (loss) income, net of related tax effects, which have not been material to date.

Recent Accounting Pronouncements

Presentation of Comprehensive Income

In June 2011, the FASB issued ASU No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income* (ASU 2011-05) which requires an entity to present total comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. ASU 2011-05 does not change any of the components of comprehensive income, but it eliminates the option to present the components of other comprehensive income as part of the statement of stockholders equity. ASU 2011-05 was effective for the Company in the first quarter of 2012 and should be applied retrospectively. As such, the Company adopted ASU 2011-05 in 2012 and has provided a separate statement of comprehensive income (loss) in its consolidated financial statements.

In December 2011, the FASB issued ASU 2011-12, deferring certain provisions of ASU 2011-05. One of the provisions of ASU 2011-05 required entities to present reclassification adjustments out of accumulated other comprehensive income (loss) by component in both the statement in which net income is presented and the statement in which other comprehensive income (loss) is presented (for both interim and annual financial statements). This requirement is indefinitely deferred by ASU 2011-12 and will be further deliberated by the FASB at a future date. The effective date of ASU 2011-12 is the same as that for the unaffected provisions of ASU 2011-05.

Disclosures about Offsetting Assets and Liabilities

In December 2011, the FASB issued ASU No. 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities* (ASU No. 2011-11). ASU No. 2011-11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. An entity is required to apply ASU No. 2011-11 for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by ASU No. 2011-11 retrospectively for all comparative periods presented. The Company does not expect that the adoption of ASU No. 2011-11 will have a significant, if any, impact on its consolidated financial statements.

2. Acquisitions

Energy Response

The Company and one of its subsidiaries acquired all of the outstanding capital stock of Energy Response, a privately-held company headquartered in Australia and specializing in demand response and other energy management services in Australia and New Zealand, pursuant to a definitive agreement dated July 1, 2011. The Company believes that Energy Response will enhance and broaden the Company's service offerings in Australia and New Zealand.

The Company concluded that the acquisition of Energy Response represented a material business combination under the provisions of ASC 805, *Business Combinations* (ASC 805), and therefore, pro forma financial information has been provided herein. Subsequent to the acquisition date, the Company's results of operations include the results of operations of Energy Response.

The Company acquired Energy Response for an aggregate purchase price, exclusive of potential contingent consideration, of $29,286, plus an additional $470 paid as working capital and other adjustments, consisting of $27,265 in cash paid at closing and $2,491 representing the fair value of the 156,697 shares of Company common stock issued as of the acquisition date. Of the consideration paid at closing, $2,646 was paid as consideration to settle Energy Response's outstanding debt obligations. In addition to the amounts paid at closing, the Company may be obligated to pay additional contingent purchase price consideration related to an earn-out payment equal to $10,374 at December 31, 2012 exchange rates ($10,000 Australian). The earn-out payment, if any, will be based on the development of a demand response reserve capacity market in the National Electricity Market in Australia by December 31, 2013 that meets certain market size and price per megawatt conditions. This milestone needs to be achieved in order for the earn-out payment to occur. There will be no partial payment if the milestone is not fully achieved. The Company determined that the initial fair value of the earn-out payment as of the acquisition date was $309. This fair value was included as a component of the purchase price resulting in an aggregate purchase price of $30,065. Any changes in fair value will be recorded in the Company's consolidated statements of operations.

The Company recorded its estimate of the fair value of the contingent consideration based on the evaluation of the likelihood of the achievement of the contractual conditions that would result in the payment of the contingent consideration and weighted probability assumptions of these outcomes. This fair value measurement was based on significant inputs not observable in the market and therefore, represented a Level 3 measurement as defined in ASC 820. There have been no changes in the probability of the earn-out payment through December 31, 2012. This liability has been discounted to reflect the time value of money and therefore, as the milestone date approaches, the fair value of this liability will increase. This increase in fair value was recorded in general and administrative expenses in the Company's accompanying consolidated statements of operations.

During the years ended December 31, 2012, and 2011, the Company recorded a charge of $95 and $46, respectively. At December 31, 2012, the liability was recorded at $431 after adjusting for changes in exchange rates. The difference between the $29,286 aggregate purchase price and the $29,475 aggregate purchase price set forth in the definitive agreement was due to the fair value of the stock issued in connection with the acquisition, which was based on the Company's stock price as of the closing date of the acquisition of $15.90 per share, as reported on the NASDAQ Global Market (NASDAQ), as compared to a per share value of $17.10 determined in accordance with the definitive agreement, which was based on the average of the per share last sale price as reported on NASDAQ for the Company's common stock for the thirty day period ending two trading days prior to closing.

Transaction costs of $500 related to this business combination were expensed as incurred and are included in general and administrative expenses in the Company's consolidated statements of operations.

The components and allocation of the purchase price consist of the following approximate amounts:

Net tangible assets acquired as of July 1, 2011	$ 194
Customer relationships	16,400
Non-compete agreements	79
Developed technology	165
Trade name	199
Goodwill	13,028
Total	$30,065

Net tangible assets acquired in the acquisition of Energy Response primarily related to the following:

Cash	$ 695
Restricted cash	2,237
Accounts receivable	148
Unbilled revenue	633
Prepaids and other assets	756
Forward energy contracts (current asset)	144
Property and equipment	780
Accounts payable	(1,114)
Amounts due to former stockholders	(2,051)
Accrued expenses and other liabilities	(1,902)
Forward energy contracts (current liability)	(132)
Total	$ 194

Restricted cash acquired related primarily to certain security deposits posted by Energy Response to collateralize its performance obligations under certain contractual arrangements with electric power grid operator customers. In accordance with the definitive agreement, the Company was required to distribute to the former stockholders of Energy Response $2,051 of this restricted cash upon the amount being released by the applicable electric power grid operator customers. This amount was classified as an amount due to the former stockholders in the reconciliation of net tangible assets acquired above and was released by the electric power grid operator customers and distributed to the former stockholders in 2011. The remaining restricted cash related to amounts used to collateralize Energy Response's obligations under certain of its facility operating lease arrangements. The acquired forward energy contracts represented derivative instruments that were recognized at their fair values. The Company determined the fair value of these derivative instruments using the framework prescribed by ASC 820, by considering the estimated amount that would be received or paid to sell or transfer these instruments at the reporting date and by taking into account current interest rates, current energy rates, and the creditworthiness of the applicable counterparty. These acquired forward energy contracts were short-term arrangements which either expired or were terminated in 2011. The Company has not entered into any additional forward energy contracts since the acquisition date. From the date of acquisition through the date of expiration or termination, the change in fair value of these forward energy contracts was not material and was included in other income (expense), net in the accompanying consolidated statements of operations.

Identifiable Intangible Assets

As part of the purchase price allocation, the Company determined that Energy Response's separately identifiable intangible assets were its customer relationships, non-compete agreements, developed technology and trade name. Developed technology represented certain proprietary software tools that Energy Response had developed, which are utilized to assist in the management of certain contractual arrangements. As of the date of acquisition, the Company determined that there was no in-process research and development as the ongoing research and development efforts were nominal and related to routine, on-going maintenance efforts.

The Company used the income approach to value the customer relationships, non-compete agreements, developed technology and trade name. This approach calculates fair value by discounting the after-tax cash flows back to a present value. The baseline data for this analysis was the cash flow estimates used to price the transaction. Cash flows were forecasted for each intangible asset then discounted based on an appropriate discount rate. The discount rates applied, which ranged between 12% and 17%, were benchmarked with reference to the implied rate of return from the transaction model, as well as an estimate of a market-participant's weighted average cost of capital based on the capital asset pricing model.

In estimating the useful life of the acquired assets, the Company considered ASC 350-30-35, *General Intangibles Other Than Goodwill* (ASC 350-30-35), and reviewed the following factors: the expected use by the combined company of the assets acquired, the expected useful life of another asset (or group of assets) related to the acquired assets, legal, regulatory or other contractual provisions that may limit the useful life of an acquired asset or may enable the extension of the useful life of an acquired asset without substantial cost, the effects of obsolescence, demand, competition and other economic factors, and the level of maintenance expenditures required to obtain the expected future cash flows from the asset. The Company amortizes these intangible assets over their estimated useful lives using a method that is based on estimated future cash flows, as the Company believes this will approximate the pattern in which the economic benefits of the assets will be utilized, or where the Company has concluded that the cash flows were not reliably determinable, on a straight-line basis.

Subsequent to the acquisition, the Company discontinued the use of the trade name intangible asset and recorded an impairment charge of $199. This amount is included in selling and marketing expense in the accompanying consolidated statements of operations for the year ended December 31, 2011.

The factors contributing to the recognition of this amount of goodwill were based upon the Company's determination that several strategic and synergistic benefits are expected to be realized from the combination. None of the goodwill is expected to be currently deductible for tax purposes.

As noted above, the Company's consolidated results of operations for the year ended December 31, 2011 include the results of operations for Energy Response from the date of acquisition through December 31, 2011, which included net revenues of $3,534 and net loss of $4,151.

The following unaudited pro forma financial information presents the consolidated results of operations of the Company and Energy Response as if the acquisition had occurred at the beginning of fiscal 2010 with pro forma adjustments to give effect to amortization of intangible assets, a decrease in interest expense as all of Energy Response's debt arrangement was settled in connection with the acquisition, an increase in the weighted average number of common shares outstanding based on the shares issued in connection with the acquisition and certain other adjustments:

	Year ended December 31,	
	2011	2010
Net revenue	$289,803	$282,610
Net (loss) income	$(16,317)	$ 4,140
Net (loss) income per common share:		
Basic	$ (0.63)	$ 0.17
Diluted	$ (0.63)	$ 0.16

The direct acquisition fees and expenses of approximately $500 that were a direct result of the transaction are excluded from the unaudited pro forma information above for the year ended December 31, 2011. The unaudited pro forma financial information for the year ended December 31, 2010 was adjusted to include these charges. The unaudited pro forma results are not necessarily indicative of the results that the Company would have attained had the acquisitions of Energy Response occurred on January 1, 2010.

Global Energy Partners, Inc.

In January 2011, the Company acquired all of the outstanding capital stock of Global Energy Partners, Inc. (Global Energy), a privately-held company located in California and specializing in the design and implementation of utility energy efficiency and demand response programs. The Company believes that Global Energy's service offerings will enhance and broaden its portfolio of service offerings in the area of energy efficiency and demand response.

The Company accounted for the acquisition of Global Energy as a purchase of a business under ASC 805, but concluded that it did not represent a material business combination and therefore, no pro forma financial information has been provided herein. Subsequent to the acquisition date, the Company's results of operations include the results of operations of Global Energy.

The total purchase price paid by the Company at closing was approximately $26,658, consisting of $19,875 in cash and the remainder of which was paid by the issuance of 275,181 shares of the Company's common stock that had a fair value of approximately $6,783. The fair value of these shares was measured as of the acquisition date using the closing price of the Company's common stock, as reported on NASDAQ on January 3, 2011. This acquisition had no contingent consideration or earn-out payments.

Transaction costs related to this business combination were not material and were included in general and administrative expenses in the accompanying consolidated statements of operations.

The components and allocation of the purchase price consist of the following approximate amounts:

Net tangible assets acquired as of January 3, 2011	$ 572
Customer relationships	6,430
Non-compete agreements	420
Developed technology	50
Trade name	260
Goodwill	18,926
Total	$26,658

Net tangible assets acquired in the acquisition of Global Energy primarily related to the following:

Cash	$ 273
Accounts receivable	1,049
Prepaids and other assets	35
Property and equipment	183
Accounts payable	(196)
Accrued expenses and other liabilities	(772)
Total	$ 572

Identifiable Intangible Assets

As part of the purchase price allocation, the Company determined that Global Energy's separately identifiable intangible assets were its customer relationships, non-compete agreements, developed technology and trade name. As of the date of acquisition, the Company determined that there was no in-process research and development as the ongoing research and development efforts were nominal and related to routine, on-going maintenance efforts.

The Company used the income approach to value the customer relationships, non-compete agreements, developed technology and trade name. This approach calculates fair value by discounting the after-tax cash flows back to a present value. The baseline data for this analysis was the cash flow estimates used to price the transaction. Cash flows were forecasted for each intangible asset then discounted based on an appropriate discount rate. The discount rates applied, which ranged between 10% and 16%, were benchmarked with reference to the implied rate of return from the transaction model as well as an estimate of a market-participant's weighted average cost of capital based on the capital asset pricing model.

In estimating the useful life of the acquired assets, the Company considered ASC 350-30-35, and reviewed the following: the expected use by the combined company of the assets acquired, the expected useful life of another asset (or group of assets) related to the acquired assets, legal, regulatory or other contractual provisions that may limit the useful life of an acquired asset or may enable the extension of the useful life of an acquired asset without substantial cost, the effects of obsolescence, demand, competition and other economic factors, and the level of maintenance expenditures required to obtain the expected future cash flows from the asset. The Company amortizes these intangible assets over their estimated useful lives using a method that is based on estimated future cash flows, as the Company believes this will approximate the pattern in which the economic benefits of the assets will be utilized, or where the Company has concluded that the cash flows were not reliably determinable, on a straight-line basis. The acquisition of Global Energy was deemed to be an asset purchase for income tax purposes. Accordingly, no deferred taxes were established relating to the fair value of the acquired intangible assets.

The factors contributing to the recognition of this amount of goodwill were based upon several strategic and synergistic benefits that are expected to be realized from the combination. Substantially all of the goodwill is expected to be deductible for tax purposes.

M2M Communications Corporation

On January 25, 2011, the Company acquired all of the outstanding capital stock of M2M Communications Corporation (M2M). By integrating M2M's wireless technology solutions with the Company's energy management applications and services, the Company believes that it will be able to enhance its automated demand response offering and deliver more value to its rapidly growing C&I customer base.

The Company accounted for the acquisition of M2M as a purchase of a business under ASC 805 but concluded that it did not represent a material business combination and therefore, no pro forma financial information has been provided herein. Subsequent to the acquisition date, the Company's results of operations include the results of operations of M2M.

The total initial purchase price paid by the Company at closing was approximately $29,871, consisting of $17,597 in cash, $3,925 representing the estimated fair value of $7,000 of deferred purchase price consideration determined at closing, and the remainder of which was paid by the issuance of 351,665 shares of the Company's common stock that had a fair value of approximately $8,349. The fair value of these shares was measured as of the acquisition date using the closing price of the Company's common stock, as reported on NASDAQ on January 25, 2011. The deferred purchase price consideration of $7,000 will be paid upon the earlier of the satisfaction of certain conditions contained in the definitive agreement or seven years after the acquisition date of January 25, 2011. The deferred purchase price consideration is not subject to adjustment or forfeiture.

The Company recorded its estimate of the fair value of the deferred purchase price consideration based on the evaluation of the likelihood of the achievement of the contractual conditions that would result in the payment of the deferred purchase price consideration prior to seven years from the acquisition date and weighted probability assumptions of these outcomes. This fair value measurement was based on significant inputs not observable in the market and therefore, represented a Level 3 measurement as defined in ASC 820. This liability has been discounted to reflect the time value of money and therefore, as the milestone date approaches, the fair value of this liability will increase. With respect to the cash portion of the deferred purchase price consideration, which had a fair value as of the acquisition date of $485, the increase in fair value is recorded as an expense in the Company's accompanying consolidated statements of operations with the portion of the charge related to the component of the deferred purchase price consideration related to the achievement of certain gross profit metrics being recorded to cost of revenues, and the remaining portion of the charge being recorded to general and administrative expenses. For the years ended December 31, 2012 and 2011, the amortization of the time value of money discount was not material. As of December 31, 2012, the Company expects that the deferred purchase price consideration will not be paid prior to seven years from the date of acquisition. Furthermore, any change in the probability of the timing of the payout would not have a material impact on the fair value of the deferred purchase price consideration. This acquisition had no contingent consideration or earn-out payments.

Transaction costs related to this business combination were not material and are included in general and administrative expenses in the accompanying consolidated statements of operations.

The allocation of the purchase price is based upon estimates of the fair value of assets acquired and liabilities assumed as of January 25, 2011.

The components and allocation of the purchase price consist of the following approximate amounts:

Net tangible assets acquired as of January 25, 2011	$ 1,340
Customer relationships	2,700
Non-compete agreements	450
Developed technology	1,700
Trade name	200
Goodwill	22,231
Total	$28,621

Net tangible assets acquired in the acquisition of M2M primarily related to the following:

Cash	$ 70
Accounts receivable	1,444
Inventory	437
Property and equipment	272
Other current assets	182
Accounts payable	(458)
Accrued expenses	(94)
Borrowing under line of credit arrangement	(500)
Other long-term liabilities	(13)
Total	$1,340

In connection with the acquisition of M2M, the Company acquired M2M's outstanding borrowings under M2M's line of credit arrangement with a financial institution. At closing, the Company fully repaid these borrowings and M2M's line of credit arrangement was terminated.

Identifiable Intangible Assets

As part of the purchase price allocation, the Company determined that M2M's separately identifiable intangible assets were its customer relationships, non-compete agreements, developed technology and trade name. As of the date of the acquisition, the Company determined that there was no in-process research and development as the ongoing research and development efforts related solely to routine, on-going efforts to refine, enrich, or otherwise improve the qualities of the existing product, and the adaptation of existing capability to a particular requirement or customer's need as part of a contractual arrangement (i.e. configuring equipment for specific customer requirements), which do not meet the criteria of in-process research and development.

The Company used the income approach to value the customer relationships, non-compete agreements, developed technology and trade name. This approach calculates fair value by discounting the after-tax cash flows back to a present value. The baseline data for this analysis was the cash flow estimates used to price the transaction. Cash flows were forecasted for each intangible asset then discounted based on an appropriate discount rate. The discount rates applied, which ranged between 10% and 18%, were benchmarked with reference to the implied rate of return from the transaction model, as well as an estimate of a market-participant's weighted average cost of capital based on the capital asset pricing model.

In estimating the useful life of the acquired assets, the Company considered ASC 350-30-35, which lists the pertinent factors to be considered when estimating the useful life of an intangible asset. These factors include a review of the expected use by the combined company of the assets acquired, the expected useful life of another asset (or group of assets) related to the acquired assets, legal, regulatory or other contractual provisions that may limit the useful life of an acquired asset or may enable the extension of the useful life of an acquired asset without substantial cost, the effects of obsolescence, demand, competition and other economic factors, and the level of maintenance expenditures required to obtain the expected future cash flows from the asset. The Company amortizes these intangible assets over their estimated useful lives using a method that is based on estimated future cash flows, as the Company believes this will approximate the pattern in which the economic benefits of the assets will be utilized, or where the Company has concluded that the cash flows were not reliably determinable, on a straight-line basis. The acquisition of M2M was deemed to be an asset purchase for income tax purposes. Accordingly, no deferred taxes were established relating to the fair value of the acquired intangible assets.

The factors contributing to the recognition of this amount of goodwill were based upon the Company's determination that several strategic and synergistic benefits are expected to be realized from the combination. Substantially all of the goodwill is expected to be deductible for tax purposes.

Other Immaterial Acquisition

In January 2011, the Company completed its acquisition of a privately-held company specializing in demand response and other energy management services. The Company believes that this acquisition will enhance and broaden the Company's international service offerings.

The Company concluded that this acquisition did not represent a material business combination and therefore, no pro forma financial information has been provided herein. Subsequent to the acquisition date, the Company's results of operations include the results of operations of the acquired company. The Company accounted for this acquisition as a purchase of a business under ASC 805.

The total purchase price paid by the Company at closing was approximately $5,193, consisting of $3,918 in cash at closing, $779 paid as consideration to settle the acquired company's outstanding debt obligations and $496 of cash consideration to be paid upon satisfaction of certain general representations and warranties. The cash consideration, which was to be paid in one year or less and is included in accrued expenses and other current liabilities in the accompanying consolidated balance sheets as of December 31, 2011, was subsequently paid in January 2012. This acquisition had no contingent consideration or earn-out payments. The Company did not issue any shares of its capital stock in connection with this acquisition.

Transaction costs related to this business combination were not material and are included in general and administrative expenses in the accompanying consolidated statements of operations.

The allocation of the purchase price is based upon estimates of the fair value of assets acquired and liabilities assumed as of January 25, 2011.

The components and allocation of the purchase price consist of the following approximate amounts:

Net tangible liabilities assumed as of January 25, 2011	$ (319)
Customer relationships	4,400
Non-compete agreements	20
Trade name	50
Goodwill	1,042
Total	$5,193

Net tangible liabilities assumed in this acquisition primarily related to the following:

Other receivables	$ 35
Accounts payable	(354)
Total	$(319)

Identifiable Intangible Assets

As part of the purchase price allocation, the Company determined that the acquired company's separately identifiable intangible assets were its customer relationships, non-compete agreements and trade name. The acquired company had no developed technology nor were there any ongoing research and development efforts as of the date of acquisition.

The Company used the income approach to value the customer relationships, non-compete agreements and trade name. This approach calculates fair value by discounting the after-tax cash flows back to a present value. The baseline data for this analysis was the cash flow estimates used to price the transaction. Cash flows were forecasted for each intangible asset then discounted based on an appropriate discount rate. The discount rates applied, which ranged between 16% and 28%, were benchmarked with reference to the implied rate of return from the transaction model, as well as an estimate of a market-participant's weighted average cost of capital based on the capital asset pricing model.

In estimating the useful life of the acquired assets, the Company considered ASC 350-30-35, which lists the pertinent factors to be considered when estimating the useful life of an intangible asset. These factors include a review of the expected use by the combined company of the assets acquired, the expected useful life of another asset (or group of assets) related to the acquired assets, legal, regulatory or other contractual provisions that may limit the useful life of an acquired asset or may enable the extension of the useful life of an acquired asset without substantial cost, the effects of obsolescence, demand, competition and other economic factors, and the level of maintenance expenditures required to obtain the expected future cash flows from the asset. The Company amortizes these intangible assets over their estimated useful lives using a method that is based on estimated future cash flows, as the Company believes this will approximate the pattern in which the economic benefits of the assets will be utilized, or where the Company concluded that the cash flows were not reliably determinable, on a straight-line basis.

The factors contributing to the recognition of this amount of goodwill were based upon the Company's determination that several strategic and synergistic benefits were expected to be realized from the combination. None of the goodwill is expected to be currently deductible for tax purposes.

SmallFoot LLC and ZOX, LLC

In March 2010, the Company acquired substantially all of the assets and certain liabilities of SmallFoot LLC (SmallFoot) and Zox, LLC (Zox) which were companies unaffiliated with the Company but were entities under common control. SmallFoot was in the process of developing wireless systems that manage and coordinate electricity demand for small commercial facilities and Zox was in the process of developing hardware and software for automated utility meter reading. The total purchase price paid by the Company at closing was approximately $1,360, of which $1,100 was paid in cash and the remainder of which was paid by the issuance of 8,758 shares of the Company's common stock that had a fair value of approximately $260. These shares were measured as of the acquisition date using the closing price of the Company's common stock, as reported on NASDAQ on March 15, 2010. The Company believes that SmallFoot's technology will reduce deployment costs and accelerate deeper market penetration into C&I customers, specifically smaller C&I customers. The Company believes Zox's smart grid communications and metering technology provides a platform for transforming electric industry legacy meters into smart meters at a substantially lower cost as compared to traditional replacement methods.

Although SmallFoot and Zox were development stage entities as of the acquisition close date, these entities met the definition of a business as defined under ASC 805 as these entities had inputs and processes that have the ability to provide a return to its owners. As a result, this acquisition was treated as a business combination in accordance with ASC 805.

Transaction costs related to this business combination were not material and are included in general and administrative expenses in the accompanying consolidated statements of operations

The allocation of the purchase price is based upon estimates of the fair value of assets acquired and liabilities assumed as of March 15, 2010. There were no net tangible assets acquired in connection with this acquisition. The components and allocation of the purchase price consists of the following approximate amounts:

In-process research and development	$ 920
Patents	200
Goodwill	240
Total	$1,360

As part of the purchase price allocation, the Company determined that the identifiable intangible assets include two in-process research and development projects and certain acquired patents. As of December 31, 2012, there were no indefinite-lived intangible assets related to in-process research and development projects.

The Company used the cost approach to value the two acquired in-process research and development projects that related to the development of wireless systems that manage and coordinate electricity demand for small commercial facilities and the development of hardware and software for automated utility meter reading, but had not yet reached technological feasibility and had no alternate future uses as of the acquisition date. The primary basis for determining the technological feasibility of these projects is the completion of a working model that performs all the major functions planned for the product and is ready for initial customer testing, usually identified as beta testing. ASC 805 requires that purchased research and development acquired in a business combination be recognized as an indefinite-lived intangible asset until the completion or abandonment of the associated research and development efforts. The cost approach calculates fair value by calculating the reproduction cost of an exact replica of the subject intangible asset. The Company calculated the replacement cost based on actual development costs incurred through the date of acquisition. In determining the appropriate valuation methodology, the Company considered, among other factors: the in-process projects' stage of completion; the complexity of the work completed as of the acquisition date; the costs already incurred; the projected costs to complete; the expected introduction date; and the estimated useful life of the technology. Given the stage of development as of the acquisition date and the current lack of sufficient information regarding future expected cash flows, the Company determined that the cost approach was the most reliable valuation methodology to determine the fair value of the in-process research and development projects acquired. The Company believes that the estimated in-process research and development amounts so determined represent the fair value at the date of acquisition and do not exceed the amount a third party would pay for the projects. However, if the projects are not successful or completed in a timely manner, the Company may not realize the financial benefits expected for these projects or for the acquisition as a whole.

The Company used the income approach to value the acquired patents. The discount rate used in connection with this valuation was 25% and was based on the commercial and technical risks related to this asset and on estimated market participant discount rates for a similar asset.

The factors contributing to the recognition of goodwill were based upon several strategic and synergistic benefits that were expected to be realized from the combination.

3. Net (Loss) Income Per Share

A reconciliation of basic and diluted share amounts for the years ended December 31, 2012, 2011, and 2010 are as follows (shares in thousands):

	Year Ended December 31,		
	2012	2011	2010
Basic weighted average common shares outstanding	26,551	25,799	24,612
Weighted average common stock equivalents	—	—	1,442
Diluted weighted average common shares outstanding	26,551	25,799	26,054
Weighted average anti-dilutive shares related to:			
Stock options	1,407	1,793	497
Non-vested restricted stock	1,709	633	127
Restricted stock units	138	269	22
Escrow shares	258	334	—

In the reporting period in which the Company reported net income, which was the year ended December 31, 2010, anti-dilutive shares comprise those common stock equivalents that have either an exercise price above the average stock price for the quarter or the common stock equivalent's related average unrecognized stock compensation expense is sufficient to "buy back" the entire amount of shares. In those reporting periods in which the Company has reported a net loss, which were the years ended December 31, 2012 and 2011, anti-dilutive shares comprise the impact of those number of shares that would have been dilutive had the Company had net income plus the number of common stock equivalents that would be anti-dilutive had the Company had net income.

The Company excludes the shares issued in connection with restricted stock awards from the calculation of basic weighted average common shares outstanding until such time as those shares vest. The Company excludes shares held in escrow in connection with certain of the Company's business combinations from the calculation of basic weighted average common shares outstanding where the release of such shares is contingent upon an event and not solely subject to the passage of time. The fixed 254,654 shares related to a component of the deferred purchase price consideration from the acquisition of M2M, which are not subject to adjustment as the issuance of such shares is not subject to any contingency, are included in both the basic and diluted weighted average common shares outstanding amounts.

In January 2013, the Company released 46,506 shares of common stock held in escrow related to the Energy Response acquisition in accordance with the provisions within the respective escrow agreement.

4. Fair Value Measurements

ASC 820 establishes a fair value hierarchy that requires the use of observable market data, when available, and prioritizes the inputs to valuation techniques used to measure fair value in the following categories:

- Level 1—Valuation is based upon quoted prices for identical instruments traded in active markets. Level 1 instruments include securities traded on active exchange markets, such as the New York Stock Exchange.
- Level 2—Valuation is based upon quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active and model-based valuation techniques for which all significant assumptions are observable in the market.
- Level 3—Valuation is generated from model-based techniques that use significant assumptions not observable in the market. These unobservable assumptions reflect the Company's own estimates of assumptions market participants would use in pricing the asset or liability.

The table below presents the balances of assets and liabilities measured at fair value on a recurring basis at December 31, 2012:

	Fair Value Measurement at December 31, 2012 Using			
	Totals	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Unobservable Inputs (Level 3)**
Liabilities:				
Deferred acquisition consideration (1)	$533	$—	$—	$533
Accrued acquisition contingent consideration (1)	431	—	—	431
	$ 964	$—	$—	$964

(1) Deferred acquisition consideration and accrued acquisition contingent consideration, which are liabilities and were the result of the Company's acquisition of M2M and Energy Response, respectively, represent the only assets or liabilities that the Company measures and records at fair value on a recurring basis using significant unobservable inputs (Level 3). The aggregate increase in fair value of liabilities for the year ended December 31, 2012 of $128 was due to the increase in the liabilities as a result of the amortization of the applicable discounts related to the time value of money of $121 and changes in exchange rates. There have been no changes with respect to the probability or timing of payment subsequent to December 31, 2012.

With respect to assets measured at fair value on a non-recurring basis, which would be impaired long-lived assets and impaired intangible assets, refer to Note 1 for discussion of the determination of fair value of these assets.

The table below presents the balances of assets and liabilities measured at fair value on a recurring basis at December 31, 2011:

	Fair Value Measurement at December 31, 2011 Using			
	Totals	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Assets:				
Money market funds(1)	$51,841	$51,841	$—	$ —
Liabilities:				
Deferred acquisition consideration (2)	500	—	—	500
Accrued acquisition contingent consideration (2)	336	—	—	336
	$ 836	$ —	$—	$836

(1) Included in cash and cash equivalents in the accompanying consolidated balance sheets.

(2) Deferred acquisition consideration and accrued acquisition contingent consideration, which are liabilities, that were the result of the Company's acquisition of M2M and Energy Response, respectively, represent the only assets or liabilities that the Company measures and records at fair value on a recurring basis using significant unobservable inputs (Level 3).

5. Allowance for Doubtful Accounts

The Company reduces gross trade accounts receivable by an allowance for doubtful accounts based on the Company's best estimate of the amount of probable credit losses in the Company's existing accounts receivable. The Company reviews its allowance for doubtful accounts on a regular basis and all past due balances are reviewed individually for collectability. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. Provisions for allowance for doubtful accounts are recorded in general and administrative expenses. Below is a summary of the changes in the Company's allowance for doubtful accounts for the years ended December 31, 2012, 2011 and 2010.

	Balance at Beginning of Period	Additions Charged to Expense	Deductions — Write-offs, Payments and Other Adjustments	Balance at End of Period
Year ended December 31, 2012	$192	$320	$ (25)	$487
Year ended December 31, 2011	$150	$215	$(173)	$192
Year ended December 31, 2010	$ 57	$160	$ (67)	$150

6. Property and Equipment

Property and equipment as of December 31, 2012 and December 31, 2011 consisted of the following:

	Estimated Useful Life (Years)	December 31, 2012	December 31, 2011
Computers and office equipment	3	$ 19,980	$ 16,855
Software	2 - 5	24,718	20,019
Demand response equipment	Lesser of useful life or estimated commercial, institutional and industrial customer relationship period	39,997	34,620
Back-up generators	5 - 10	8,519	9,436
Furniture and fixtures	5	1,827	1,706
Leasehold improvements	Lesser of the useful life or original lease term	3,034	2,419
Construction-in-progress		2,426	2,981
		100,501	88,036
Accumulated depreciation		(67,909)	(51,400)
Property and equipment, net		$ 32,592	$ 36,636

Depreciation expense was $17,977, $16,187 and $14,414 for the years ended December 31, 2012, 2011 and 2010, respectively. For the years ended December 31, 2012, 2011 and 2010, $12,256, $11,614 and $9,907, respectively, were included in cost of revenues, and $5,721, $4,573 and $4,507, respectively, were included in general and administrative expenses.

7. Financing Arrangements

The Company has a $50,000 senior secured revolving credit facility pursuant to a credit agreement with Silicon Valley Bank (SVB) (the 2012 credit facility), as amended. Subject to continued compliance with the covenants contained in the 2012 credit facility, the full amount of the 2012 credit facility may be available for issuances of letters of credit and up to $5,000 of the 2012 credit facility may be available for swing line loans. The interest on revolving loans under the 2012 credit facility will accrue, at the Company's election, at either (i) the Eurodollar Rate with respect to the relevant interest period plus 2.00% or (ii) the ABR (defined as the highest of (x) the "prime rate" as quoted in the *Wall Street Journal*, (y) the Federal Funds Effective Rate plus 0.50% and (z) the Eurodollar Rate for a one-month interest period plus 1.00%) plus 1.00%. The Company expenses the interest and letter of credit fees under the 2012 credit facility, as applicable, in the period incurred. The obligations under the 2012 credit facility are secured by all domestic assets of the Company and several of its subsidiaries, excluding the Company's foreign subsidiaries. The 2012 credit facility terminates and all amounts outstanding thereunder are due and payable in full on April 15, 2013. The Company incurred financing costs of $543 in connection with the original credit facility and $111 in connection with subsequent amendments which were deferred and are being amortized to interest expense over the term of the 2012 credit facility, or through April 15, 2013.

The 2012 credit facility contains customary terms and conditions for credit facilities of this type, including, among other things, restrictions on the ability of the Company and its subsidiaries to incur additional indebtedness, create liens, enter into transactions with affiliates, transfer assets, make certain acquisitions, pay dividends or make distributions on, or repurchase, the Company's common stock, consolidate or merge with other entities, or undergo a change in control. In addition, the Company is required to meet certain monthly and quarterly financial covenants customary with this type of credit facility.

The 2012 credit facility contains customary events of default, including for payment defaults, breaches of representations, breaches of affirmative or negative covenants, cross defaults to other material indebtedness, bankruptcy and failure to discharge certain judgments. If a default occurs and is not cured within any applicable cure period or is not waived, SVB may accelerate the Company's obligations under the 2012 credit facility; and the Company would be required to collateralize with cash any outstanding letters of credit up to 105% of the amounts outstanding.

As of December 31, 2012,, the Company was in compliance with all of its covenants under the 2012 credit facility. The Company believes that it is reasonably assured that it will comply with the covenants under the 2012 credit facility for the foreseeable future.

As of December 31, 2012, the Company had no borrowings and outstanding letters of credit totaling $42,622 under the 2012 credit facility. As of December 31, 2012, the Company had $7,378 available under the 2012 credit facility for future borrowings or issuances of additional letters of credit. Upon termination of the 2012 credit facility in April 2013, if the Company has not entered into a new credit facility, the Company would be required to cash collateralize its outstanding letters of credit with SVB at an amount up to 105% of the outstanding amounts.

8. Stockholders' Equity

In May 2007, the Company's board of directors approved an amendment and restatement of the Company's Certificate of Incorporation to increase the authorized number of shares of common stock to 50,000,000, to authorize 5,000,000 shares of undesignated preferred stock, and to eliminate all references to the designated Series Preferred Stock. At December 31, 2012, the Company has authorized 50,000,000 shares of common stock, of which 29,019,923 shares were issued and outstanding and 786,872 shares have been reserved for future issuance under the Company's Amended and Restated 2007 Employee, Director and Consultant Stock Plan (the 2007 Plan).

9. Stock-Based Compensation

The Company's Amended and Restated 2003 Stock Option and Incentive Plan (2003 Plan) and the 2007 Plan (collectively the Plans) provide for the grant of incentive stock options, nonqualified stock options, restricted and unrestricted stock awards and other stock-based awards to eligible employees, directors and consultants of the Company. Options granted under the Plans are exercisable for a period determined by the Company, but in no event longer than ten years from the date of the grant. Option awards are generally granted with an exercise price equal to the market price of the Company's common stock on the date of grant. Options, restricted stock awards and restricted stock unit awards generally vest ratably over four years, with certain exceptions. The 2003 Plan expired upon the Company's initial public offering (IPO) in May 2007. Any forfeitures under the 2003 Plan that occurred after the effective date of the IPO are available for future grant under the 2007 Plan up to a maximum of 1,000,000 shares. The 2007 Plan provides for an annual increase to the shares issuable under the 2007 Plan by an amount equal to the lesser of 520,000 shares or an amount determined by the Company's board of directors. This annual increase is effective on the first day of each fiscal year through 2017. The annual increase for the years ended December 31, 2012, 2011 and 2010 was 520,000 shares, respectively. During the years ended December 31, 2012, 2011, and 2010, the Company issued 44,871, 18,211 and 24,681 shares of its common stock, respectively, to certain executives to satisfy a portion of the Company's bonus obligations to those individuals. As of December 31, 2012, 786,872 shares were available for future grant under the 2007 Plan.

Stock Options

The fair value of options granted was estimated at the date of grant using the following weighted average assumptions:

	Year Ended December 31,		
	2012	2011	2010
Risk-free interest rate	1.8%	3.2%	3.5%
Vesting term, in years	2.22	2.22	2.17
Expected annual volatility	78%	80%	85%
Expected dividend yield	—%	—%	—%
Exit rate pre-vesting	8.00%	8.00%	5.95%
Exit rate post-vesting	14.06%	14.06%	11.49%

Volatility measures the amount that a stock price has fluctuated or is expected to fluctuate during a period. The Company calculates volatility using a component of implied volatility and historical volatility to determine the value of share-based payments. The risk-free interest rate is the rate available as of the option date on zero-coupon United States government issues with a term equal to the expected life of the option. The Company has not paid dividends on its common stock in the past and does not plan to pay any dividends in the foreseeable future. In addition, the terms of the 2012 credit facility preclude the Company from paying dividends. During the year ended December 31, 2012, the Company updated its estimated exit rate pre-vesting and post-vesting applied to options, restricted stock and restricted stock units based on an evaluation of demographics of its employee groups and historical forfeitures for these groups in order to determine its option valuations as well as its stock-based compensation expense. The changes in estimates of the volatility, exit rate pre-vesting and exit rate post-vesting did not have a material impact on the Company's stock-based compensation expense recorded in the accompanying consolidated statements of operations for the year ended December 31, 2012.

The components of stock-based compensation expense are disclosed below:

	Year Ended December 31,		
	2012	2011	2010
Stock options	$ 2,046	$ 5,170	$ 9,406
Restricted stock and restricted stock units	11,570	8,294	6,336
Total	$13,616	$13,464	$15,742

Stock based compensation is recorded in the accompanying statements of operations, as follows:

	Year Ended December 31,		
	2012	2011	2010
Selling and marketing expenses	$ 4,641	$ 4,203	$ 4,583
General and administrative expenses	7,758	8,255	10,252
Research and development expenses	1,220	1,006	907
Total	$13,619	$13,464	$15,742

The stock-based compensation expense related to share-based payments to non-employees was not material for the years ended December 31, 2012, 2011 and 2010. The Company recognized no material income tax benefit from stock-based compensation arrangements during the years ended December 31, 2012, 2011 and 2010. In addition, no material compensation cost was capitalized during the years ended December 31, 2012, 2011 and 2010.

The following is a summary of the Company's stock option activity during the year ended December 31, 2012:

	Year Ended December 31, 2012			
	Number of Shares Underlying Options	Exercise Price Per Share	Weighted–Average Exercise Price Per Share	Aggregate Intrinsic Value
Outstanding at December 31, 2011	1,611,391	$0.17–$48.06	$15.35	$4,195(2)
Granted	10,800		9.00	
Exercised	(189,385)		1.88	$1,447(3)
Cancelled	(157,495)		23.71	
Outstanding at December 31, 2012	1,275,311	$0.17–$48.06	16.26	$2,915(4)
Weighted average remaining contractual life in years: 3.8				
Exercisable at end of period	1,120,890	$0.17–$48.06	$15.00	$2,878(4)
Weighted average remaining contractual life in years: 3.6				
Vested or expected to vest at December 31, 2012(1)	1,267,149	$0.17–$48.06	$16.22	$2,911(4)

(1) This represents the number of vested options as of December 31, 2012 plus the number of unvested options expected to vest as of December 31, 2012 based on the unvested options outstanding at December 31, 2012, adjusted for the estimated forfeiture rate of 8.0%.

(2) The aggregate intrinsic value was calculated based on the positive difference between the estimated fair value of the Company's common stock on December 31, 2011 of $10.87 and the exercise price of the underlying options.

(3) The aggregate intrinsic value was calculated based on the positive difference between the fair value of the Company's common stock on the applicable exercise dates and the exercise price of the underlying options.

(4) The aggregate intrinsic value was calculated based on the positive difference between the estimated fair value of the Company's common stock on December 31, 2012 of $11.75 and the exercise price of the underlying options.

Additional Information About Stock Options

	Year Ended December 31,		
In thousands, except share and per share amounts	**2012**	**2011**	**2010**
Total number of options granted during the year	10,800	44,650	312,868
Weighted–average fair value per share of options granted	$ 5.37	$ 11.32	$ 18.81
Total intrinsic value of options exercised(1)	$ 1,447	$ 3,484	$ 13,702

(1) Represents the difference between the market price at exercise and the price paid to exercise the options.

Of the stock options outstanding as of December 31, 2012, 1,265,418 options were held by employees and directors of the Company and 9,893 options were held by non-employees. For outstanding unvested stock options related to employees as of December 31, 2012, the Company had $1,728 of unrecognized stock-based compensation expense, which is expected to be recognized over a weighted average period of 1.3 years. There were no material unvested non-employee options as of December 31, 2012.

Restricted Stock and Restricted Stock Units

For non-vested restricted stock and restricted stock units subject to service-based vesting conditions outstanding as of December 31, 2012, the Company had $8,449 of unrecognized stock-based compensation expense, which is expected to be recognized over a weighted average period of 2.5 years. For non-vested restricted stock subject to performance-based vesting conditions outstanding and that were probable of vesting as of December 31, 2012, the Company had $3,856 of unrecognized stock-based compensation expense, which is expected to be recognized over a weighted average period of 1.3 years. For non-vested restricted stock subject to performance-based vesting conditions outstanding that were not probable of vesting as of December 31, 2012, the Company had $738 of unrecognized stock-based compensation expense. If and when any additional portion of these awards are deemed probable to vest, the Company will reflect the effect of the change in estimate in the period of change by recording a cumulative catch-up adjustment to retroactively apply the new estimate.

Restricted Stock

The following table summarizes the Company's restricted stock activity during the year ended December 31, 2012:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share
Non-vested at December 31, 2011	1,141,643	$15.31
Granted	1,581,878	8.07
Vested	(393,224)	17.87
Cancelled	(194,801)	12.16
Non-vested at December 31, 2012	2,135,496	$ 9.78

All shares underlying awards of restricted stock are restricted in that they are not transferable until they vest. Restricted stock typically vests ratably over a four-year period from the date of issuance, with certain exceptions. Included in the above table are 20,950 shares of restricted stock granted to certain non-executive employees and 43,793 shares of restricted stock granted to the Company's board of directors during the year ended December 31, 2012 that were immediately vested.

The fair value of restricted stock that vests solely based on service vesting conditions is expensed ratably over the vesting period. With respect to restricted stock that contains certain performance-based vesting conditions, the fair value is expensed based on the accelerated attribution method as prescribed by ASC 718 over the vesting period. During the year ended December 31, 2012, the Company granted 1,023,010 shares of non-vested restricted stock to certain executives and non-executive employees that contain performance-based vesting conditions and these awards will vest in equal installments in 2013 and 2014 if the performance conditions are achieved. If the employee who received the restricted stock leaves the Company prior to the vesting date for any reason, the shares of restricted stock will be forfeited and returned to the Company.

In November 2011, the Company's Board of Directors approved a plan to include performance-based stock awards as part of the annual non-executive bonus plan. In December 2011, 283,334 shares were issued under the 2007 Plan with a fair value of $2,700 and these awards will vest in equal installments in 2013 and 2014 if the performance conditions are achieved. Through December 31, 2011, the Company determined that no awards were probable of vesting and as a result, no stock-based compensation expense related to these awards was recorded through December 31, 2011. In March 2012, the performance conditions were modified and the Company determined that the modified performance conditions were probable of being achieved. As the performance-based stock awards were improbable of vesting prior to the modification of the performance conditions, the original grant date fair value is no longer used to measure compensation cost for the awards. The fair value of these awards was re-measured as of the modification date resulting in a new grant-date fair value of $2,132 after accounting for cancelled grants due to employee terminations. As these awards were probable of vesting as of March 31, 2012 and a portion of the service period had lapsed, the Company recorded a cumulative catch-up adjustment of stock-based compensation expense during the three months ended March 31, 2012 as required by ASC 718. During the year ended December 31, 2012, there were no changes to probabilities of existing performance-based stock awards which had a material impact on stock-based compensation expense or amounts expected to be recognized.

Additional Information About Restricted Stock

In thousands, except share and per share amounts	Year Ended December 31, 2012	2011	2010
Total number of shares of restricted stock granted during the year	1,581,878	1,062,165	247,900
Weighted average fair value per share of restricted stock granted	$ 8.07	$ 14.24	$ 30.14
Total number of shares of restricted stock vested during the year	393,224	103,131	158,943
Total fair value of shares of restricted stock vested during the year	$ 3,884	$ 1,349	$ 4,691

Restricted Stock Units

The following table summarizes the Company's restricted stock unit activity during the year ended December 31, 2012:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share
Non-vested at December 31, 2011	229,020	$26.75
Granted	—	—
Vested	(92,042)	24.44
Cancelled	(30,500)	29.75
Non-vested at December 31, 2012	106,478	$27.88

Additional Information About Restricted Stock Units

In thousands, except share and per share amounts	Year Ended December 31, 2012	2011	2010
Total number of shares of restricted stock units granted during the year	—	—	326,000
Weighted average fair value per share of restricted stock units granted	$ —	$ —	$ 28.99
Total number of shares of restricted stock units vested during the year	92,042	95,167	51,876
Total fair value of shares of restricted stock units vested during the year	$ 884	$ 1,609	$ 1,637

10. Income Taxes

The Company accounts for income taxes in accordance with ASC 740, *Income Taxes* (ASC 740), which is the asset and liability method for accounting and reporting income taxes. Under ASC 740, deferred tax assets and liabilities are recognized based on temporary differences between the financial reporting and income tax bases of assets and liabilities using statutory rates. In addition, ASC 740 requires a valuation allowance against net deferred tax assets if, based upon the available evidence, it is more likely than not that some or all of the deferred tax assets will not be realized.

Domestic and foreign pre-tax income is as follows:

	Year Ended December 31,		
	2012	2011	2010
United States	$(16,855)	$ (6,506)	$10,086
Foreign	(3,667)	(5,071)	327
	$(20,522)	$(11,577)	$10,413

The provision for income taxes is as follows:

	Year Ended December 31,		
	2012	2011	2010
Current			
Federal	$ —	$ —	$ —
State	72	233	165
Foreign	354	57	202
	426	290	367
Deferred			
Federal	1,245	1,212	401
State	242	235	87
Foreign	(142)	69	(19)
	1,345	1,516	469
	$1,771	$1,806	$836

Amounts due to various states for non-income taxes are included in general and administrative expenses and accrued expenses and other current liabilities as of December 31, 2012, 2011, and 2010.

A reconciliation of income tax expense at the statutory federal income tax rate and income taxes as reflected in the consolidated financial statements is as follows:

	Year Ended December 31,		
	2012	2011	2010
Federal income tax at statutory federal rate	(34.0)%	(34.0)%	34.0%
State taxes	1.5	3.7	1.9
Tax-deductible goodwill	6.1	10.5	3.9
Foreign losses not benefited	4.8	14.3	—
Stock-based compensation expense	1.4	3.4	8.3
Foreign dividends	—	—	4.2
Other	2.9	4.2	(0.5)
Change in valuation allowance	25.9	13.5	(43.8)
	8.6%	15.6%	8.0%

Deferred tax assets (liabilities) consisted of the following:

	Year Ended December 31, 2012	Year Ended December 31, 2011
Deferred income tax assets:		
Net operating loss carryforwards	$ 18,621	$ 19,633
Intangible assets	3,818	2,048
Reserves and accruals	1,463	1,025
Deferred revenue	3,100	233
Deferred rent	666	225
Stock options	6,830	6,808
Tax credits and other	1,591	983
Total deferred tax assets	$ 36,089	$ 30,955
Deferred tax liabilities:		
Property and equipment	$ (4,276)	$ (7,414)
Tax deductible goodwill	(4,077)	(2,588)
Total deferred tax liabilities	$ (8,353)	$(10,002)
Net deferred tax assets before valuation allowance	$ 27,736	$ 20,953
Valuation allowance	(31,718)	(23,599)
Net deferred tax liability	$ (3,982)	$ (2,646)

The Company has provided a valuation allowance against deferred tax assets in U.S., Australia, and New Zealand because it is more likely than not that these assets will not be realized. In determining realizability, the Company considered numerous factors including historical profitability and the character and amount of estimated future taxable income. However, the Company has determined that it is more likely than not that the deferred tax assets of its subsidiaries in Canada and the United Kingdom will be realized given the expected profitability of the operations in these countries. The valuation allowance increased $8,119 during the year ended December 31, 2012.

As of December 31, 2012, the Company has U.S. federal and state net operating loss carryforwards of $56,731 and $45,994, respectively, that are available to offset future federal and state taxable income. These attributes expire at various dates through 2031. The net operating loss carryforwards may be subject to the annual limitations under Section 382 of the Internal Revenue Code of 1986, as amended. The Company's U.S. net operating loss carryforwards at December 31, 2012 include $19,922 in income tax deductions related to stock options. The benefit of these losses will be reflected as a credit to additional paid-in capital as realized. In accordance with the provision of ASC 718, no valuation allowance has been recorded against this amount. The Company has U.S. tax credits of $935 that are available to reduce future U.S. tax liabilities. These credits begin to expire in 2020. Additionally, the Company has Australian federal net operating loss carryforwards of $12,913 and New Zealand federal net operating loss carryforwards of $687. These attributes may be carried forward indefinitely and used to offset taxable income in the respective jurisdictions.

As of December 31, 2011, the Company determined that no liabilities for uncertain tax positions should be recorded. During 2012, the Company recognized a $399 net increase in unrecognized tax benefits.

Activity related to unrecognized tax benefits was as following:

Balance at December 31, 2011	$ —
Additions based on tax positions related to the current year	399
Balance at December 31, 2012	$399

All of the Company's unrecognized tax benefits, if recognized, would have no impact on the effective rate as the benefit would be offset with a valuation allowance. The Company has adopted a policy that it will recognize both accrued interest and penalties related to unrecognized benefits in income tax expense, when and if recorded. The Company has not recorded any interest and penalties on any unrecognized tax benefits since inception.

The Company files income tax returns in the U.S., Australia, New Zealand, Canada and the United Kingdom. The tax years 2009 through 2012 remain open for certain U.S. federal and state tax jurisdictions, although carryforward attributes that were generated prior to 2009 may still be subject to examination. The Company's Australia, New Zealand, Canada, and United Kingdom income tax returns are no longer subject to examination for years prior to tax year 2009, 2011, 2008, and 2010 respectively. The Company is currently not under examination by any tax jurisdictions for any tax years.

The Company continues to maintain its indefinite reinvestment assertion with regards to its investment in its foreign subsidiaries. As such, it does not accrue U.S. tax for the future repatriation of these unremitted foreign earnings. As of December 31, 2012 the amount of foreign earnings that are expected to remain invested outside the U.S. indefinitely and for which no U.S. tax cost has been provided were not material. If the Company was to repatriate these earnings, it expects to utilize existing tax attributes and expects any tax liability arising as a result of a repatriation to be minimal.

11. Employee Savings and Retirement Plan

The Company has established a 401(k) Profit Sharing Plan and Trust (the 401(k) Plan) covering substantially all employees. Once the employees have met the eligibility and participation requirements under the 401(k) Plan, employees may contribute a portion of their earnings to the 401(k) Plan to be invested in various savings alternatives. Annually, at the discretion of the Company's board of directors, the Company may make matching contributions to the 401(k) Plan, which may vest ratably over periods ranging from one to three years. From inception of the 401(k) Plan through December 31, 2011, the Company had not made any matching contributions to the 401(k) Plan. For the year ended December 31, 2012, the Company approved a single discretionary contribution totaling $327. In addition, commencing in fiscal 2013, the Company will match 50% of an employee's contribution to the 401(k) Plan up to 6% and a maximum annual contribution by the Company of $2.5 per employee.

12. Commitments and Contingencies

In June 2012, the Company exercised its termination option under the current lease for its principal executive offices at 75-101 Federal Street, Boston, Massachusetts (the Current Lease) and provided notice of its election to terminate the Current Lease effective as of June 30, 2013. As a result of its election to terminate the Current Lease, the Company is required to make a lease termination payment of $1,146 of which $573 was paid upon exercise of the election to terminate and the remaining $573 is due and payable on or before July 1, 2013. In accordance with ASC 420, *Exit or Disposal Cost Obligations,* the Company recorded the fair value of this lease termination expense of $1,146 within general and administrative expenses during 2012. The Company determined the fair value of the lease termination obligation based on the $573 paid upon the election to terminate the lease plus the $573 that will be paid on or before July 1, 2013.

Pursuant to the terms of the Current Lease, in addition to the lease termination payment, the Company is required to continue to pay its contractual lease payments through the lease termination date of June 30, 2013. The Company is recording the remaining contractual lease payments ratably through the lease termination date since the Company intends to utilize the leased space through the lease termination date. As a result of its election to terminate the Current Lease, the Company re-evaluated the estimated useful life of the leasehold improvements and furniture and fixtures related to this leased space and concluded that a change in the estimated useful life is required. As a result, commencing in June 2012, the Company revised the estimated useful life of these associated assets totaling $937 to fully depreciate the remaining net book value of these assets over the shorter of their remaining useful life or the revised lease termination date.

In July 2012, the Company entered into a lease for its new principal executive offices in Boston, MA (the New Lease). Under the terms of the New Lease, the Company was required to provide a security deposit in the form of an unconditional and irrevocable letter of credit of approximately $1,845, subject to reduction commencing August 1, 2012. The New Lease term is through July 2020 and contains both a rent holiday period and escalating rental payments over the New Lease term. The New Lease requires payments for additional expenses such as taxes, maintenance, and utilities and contains a fair value renewal option. The Company is currently making certain improvements to the leased space and intends to occupy the space during the first half of the fiscal year ending December 31, 2013. In accordance with the New Lease, the landlord is providing certain lease incentives with respect to the leasehold improvements. In accordance with ASC 840, *Leases,* the Company will record the incentives as deferred rent and expense these amounts as reductions of lease expense over the lease term. Although lease payments under the New Lease do not commence until August 2013, as the Company has the right to use and controls physical access to the space, the Company has determined that the lease term commenced in July 2012 and, as a result, is recording rent expense on the New Lease on a straight-line basis. The New Lease also contains certain provisions requiring the Company to restore certain aspects of the leased space to its initial condition. The Company has determined that these provisions represent asset retirement obligations and will record the estimated fair value of these obligations as the related leasehold improvements are incurred. There have been no leasehold improvements which would result in asset retirement obligations as of December 31, 2012. The Company will accrete the liability to fair value over the life of the New Lease as a component of operating expenses.

As of December 31, 2012 and 2011, the Company had a deferred rent liability representing rent expense recorded on a straight-line basis in excess of contractual lease payments of $1,641and $432, respectively, which is included in other liabilities in the accompanying consolidated balance sheets.

At December 31, 2012, future minimum lease payments for operating leases with non-cancelable terms of more than one year were as follows:

	Operating Leases
2013	$ 5,379
2014	4,972
2015	3,967
2016	3,851
2017	3,852
Thereafter	10,378
Total minimum lease payments (not reduced by sublease rentals of $265)	$32,399

Rent expense under operating leases amounted to $6,893, $5,144 and $4,311 for the years ended December 31, 2012, 2011 and 2010, respectively.

As of December 31, 2012, the Company was contingently liable under outstanding letters of credit for $42,622. As of December 31, 2012 and December 31, 2011, the Company had restricted cash balances of $9 and $158, respectively, all of which related to collateral to secure certain insurance commitments.

The Company is subject to performance guarantee requirements under certain utility and electric power grid operator customer contracts and open market bidding program participation rules. Such guarantees may be secured by cash or letters of credit. Performance guarantees as of December 31, 2012 and 2011, were $44,510 and $34,152, respectively. These performance guarantees included deposits held by certain customers of $1,888 and 14,281, respectively, at December 31, 2012 and December 31, 2011. These amounts primarily represent up-front payments required by utility and electric power grid operator customers as a condition of participation in certain demand response programs and to ensure that the Company will deliver its committed capacity amounts in those programs. If the Company fails to meet its minimum committed capacity requirements, a portion or all of the deposit may be forfeited. The Company assessed the probability of default under these customer contracts and open market bidding programs and has determined the likelihood of default and loss of deposits to be remote. In addition, under certain utility and electric power grid operator customer contracts, if the Company does not achieve the required performance guarantee requirements, the customer can terminate the arrangement and the Company would potentially be subject to termination penalties. Under these arrangements, the Company defers all fees received up to the amount of the potential termination penalty until the Company has concluded that it can reliably determine that the potential termination penalty will not be incurred or the termination penalty lapses. As of December 31, 2012, the Company had no remaining deferred fees that were included in deferred revenues. As of December 31, 2012, the maximum termination penalty that the Company is subject to under these arrangements, which the Company has not deemed probable of incurring, is approximately $7,434.

As of December 31, 2012 and 2011, the Company has accrued in the accompanying consolidated balance sheets $685 and $6,045, respectively, of performance adjustments related to fees received for its participation in a demand response program. The decrease in the accrual from December 31, 2011 was a result of the Company repaying $6,293 to the electric power grid operator during the three month period ended September 30, 2012 since the Company did not deliver all of its MW obligations under this demand response program offset by an increase in additional performance adjustments. The Company believes that it is probable that the remaining balance will also need to be re-paid to the electric power grid operator within the next twelve months.

The Company had been involved in an ongoing regulatory matter related to a review of certain fees received under a contractual arrangement. The Company had previously determined it was probable that a loss had been incurred and had accrued the low end of the range as required under ASC 450, Contingencies, which was not material to the Company's consolidated results of operations for the year ended December 31, 2012. The Company resolved this regulatory matter for an amount that did not differ materially from the amount that the Company had accrued.

In addition to the $1,070 impairment charge discussed in Note 1, in connection with the decision that the Company made in the fourth quarter of 2012, under which it expects to net settle a portion of its future delivery obligations in a certain open market bidding program, the Company may incur additional charges and liabilities. The Company does not expect that any additional charges or liabilities would be material to the Company's consolidated results of operations and anticipates additional charges or liabilities, if any, would be substantially incurred and recorded within the Company's consolidated results of operations in fiscal 2013.

The Company has also concluded that there was no impact to its accounting for similar arrangements as the Company believes it is probable that it will physically deliver its obligations under similar arrangements. The Company also determined that the net settlement of its obligations under this program will not meet the definition of a component of an entity in accordance with ASC 205-20, *Presentation of Financial Statements—Discontinued Operations* and therefore, discontinued operations presentation is not applicable.

In connection with the Company's participation in an open market bidding program, the Company entered into an arrangement with a third party during the second quarter of 2009 to bid capacity into the program and provide the corresponding financial assurance required in connection with the bid. The arrangement included an up-front payment by the Company equal to $2,000, of which $1,100 was expensed as interest expense during the second quarter of 2009 and $900 was deferred and would be recognized ratably as a charge to cost of revenues as revenue is recognized over the 2012/2013 delivery year. In addition, the Company would be required to pay the third party an additional contingent fee, up to a maximum of $3,000, based on the revenue that the Company would earn in 2012 in connection with the bid. In December 2011, the Company and the third party entered into a termination agreement under which the Company paid a termination fee of $4,186, of which $1,000 had been previously paid. As a result of this termination agreement, the Company recorded a contract termination fee of $4,068 during the year ended December 31, 2011, which represents the $3,186 paid upon the termination and $882 that had been previously capitalized, as a component of general and administrative expenses in the accompanying consolidated statements of operations.

The Company typically grants customers a limited warranty that guarantees that its hardware will substantially conform to current specifications for one year from the delivery date. Based on the Company's operating history, the liability associated with product warranties has been determined to be nominal.

Indemnification Provisions

The Company includes indemnification provisions in certain of its contracts. These indemnification provisions include provisions indemnifying the customer against losses, expenses, and liabilities from damages that could be awarded against the customer in the event that the Company's services and related enterprise software platforms are found to infringe upon a patent or copyright of a third party. The Company believes that its internal business practices and policies and the ownership of information limits the Company's risk in paying out any claims under these indemnification provisions.

Exhibit Index

Number	Exhibit Title
2.1	Stock Purchase Agreement, dated as of December 2, 2010, by and among EnerNOC Inc., Global Energy Partners, Inc., The Global Energy Partners, Inc., Employee Stock Ownership Trust and certain individuals named herein, filed as Exhibit 2.1 to the Registrant's Form 10-K for the year ended December 31, 2010 (File No. 001-33471), is hereby incorporated by reference as Exhibit 2.1.
2.2	Agreement and Plan of Merger, dated as of January 21, 2011, by and among EnerNOC, Inc., M2M Communications Corporation, M2M Merger Sub, Inc., Steven L. Hodges, in his capacity as stockholder representative, and certain individuals named therein, filed as Exhibit 2.1 to the Registrant's Form 10-Q filed May 5, 2011 (File No. 001-33471), is hereby incorporated by reference as Exhibit 2.2.
2.3	Stock Purchase Agreement, dated as of July 1, 2011, by and among EnerNOC, Inc., EnerNOC Australia Pty Ltd, Energy Response Holdings Pty Ltd, Semibreve Pty Ltd, in its capacity as a security holder representative, and certain individuals named therein, filed as Exhibit 2.1 to the Registrant's Form 10-Q filed November 7, 2011 (File No. 001-33471), is hereby incorporated by reference as Exhibit 2.3.
3.1	Amended and Restated Certificate of Incorporation of EnerNOC, Inc., filed as Exhibit 3.2 to the Registrant's Form S-1/A filed May 3, 2007 (File No. 333-140632), is hereby incorporated by reference as Exhibit 3.1.
3.2	Amended and Restated Bylaws of EnerNOC, Inc., filed as Exhibit 3.4 to the Registrant's Form S-1/A filed May 3, 2007 (File No. 333-140632), is hereby incorporated by reference as Exhibit 3.2.
4.1	Form of Specimen Common Stock Certificate, filed as Exhibit 4.1 to the Registrant's Form S-1/A filed May 3, 2007 (File No. 333-140632), is hereby incorporated by reference as Exhibit 4.1.
4.2	Fifth Amended and Restated Investor Rights Agreement, filed as Exhibit 4.1 to the Registrant's Form 10-Q filed November 5, 2007 (File No. 001-33471), is hereby incorporated by reference as Exhibit 4.2.
10.1	Amended and Restated Credit Agreement among EnerNOC, Inc., ENOC Securities Corporation and Silicon Valley Bank, dated as of March 14. 2012, filed as Exhibit 10.1 to the Registrant's Form 10-Q filed May 8, 2012 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.1.
10.2	First Amendment to Amended and Restated Credit Agreement by and among EnerNOC, Inc., ENOC Securities Corporation and Silicon Valley Bank, dated as of June 29, 2012, filed as Exhibit 10.1 to the Registrant's Form 10-Q filed August 8, 2012 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.2.
10.3	Guarantee and Collateral Agreement made by EnerNOC, Inc. and ENOC Securities Corporation in favor of Silicon Valley Bank, dated as of April 15, 2011, filed as Exhibit 10.2 to the Registrant's Form 10-Q filed August 9, 2011 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.3.
10.4@	Second Amended and Restated Employment Agreement, dated as of March 1, 2010, by and between Timothy G. Healy and EnerNOC, Inc., as amended by the First Amendment to the Second Amended and Restated Employment Agreement, dated as of March 1, 2012, filed as Exhibit 10.3 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2011 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.4.
10.5@	Second Amended and Restated Employment Agreement, dated as of March 1, 2010, by and between David B. Brewster and EnerNOC, Inc., filed as Exhibit 10.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2009 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.5.

10.6@	Form of Severance Agreement by and between EnerNOC, Inc. and each of Gregg Dixon and David Samuels, filed as Exhibit 10.6 to the Registrant's Form S-1 filed February 12, 2007 (File No. 333-140632), is hereby incorporated by reference as Exhibit 10.6.
10.7@	Form of Amendment No. 1 to Form of Severance Agreement by and between EnerNOC, Inc, and each of Gregg Dixon and David Samuels, filed as Exhibit 10.3 to the Registrant's Form 10-Q filed August 10, 2007 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.7.
10.8#	Lease Agreement, dated as of July 5 2012, between EnerNOC, Inc. and Fallon Cornerstone ONEMPDLLC, filed as Exhibit 10.1 to the Registrant's Form 10-Q filed November 6, 2012 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.8.
10.9	Amended and Restated Office Lease, dated as of August 15, 2008, between Transwestern Federal, L.L.C. and EnerNOC, Inc., filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed August 20, 2008 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.9.
10.10	First Amendment to Amended and Restated Lease, dated as of September 16, 2011, between Aslan III Federal, L.L.C. (formerly known as Transwestern Federal, L.L.C.) and EnerNOC, Inc., filed as Exhibit 10.1 to the Registrant's Form 10-Q filed November 7, 2011 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.10.
10.11	Sub-Sublease Agreement by and between Prosodie Interactive California and EnerNOC, Inc., dated May 30, 2008, filed as Exhibit 10.1 to the Registrant's Form 10-Q filed August 13, 2008 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.11.
10.12	Agreement of Lease, dated as of September 9, 2008, between CRP/Capstone 14W Property Owner, L.L.C. and EnerNOC, Inc., filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed September 12, 2008 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.12.
10.13@	EnerNOC, Inc. Amended and Restated 2007 Employee, Director and Consultant Stock Plan and HMRC Sub-Plan for UK Employees and Australian Sub-Plan, and forms of agreement thereunder, filed as Exhibit 10.11 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2011 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.13.
10.14@*	EnerNOC, Inc. Third Amended and Restated Non-Employee Director Compensation Policy.
10.15@	Summary of 2012 and 2013 Executive Officer Bonus Plan, filed as Exhibit 10.13 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2011 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.15.
10.16@*	Summary of Revised 2013 Executive Officer Bonus Plan.
10.17@	Form of Indemnification Agreement between EnerNOC, Inc. and each of the directors and executive officers thereof, filed as Exhibit 10.21 to the Registrant's Registration Statement on Form S-1, as amended, filed May 3, 2007 (File No. 333-140632), is hereby incorporated by reference as Exhibit 10.17.
10.18@	Separation agreement with Darren Brady, filed as Exhibit 10.1 to the Registrant's Form 10-Q filed May 5, 2011 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.18.
10.19@	Severance Agreement, dated as of January 22, 2008, by and between EnerNOC, Inc. and Darren P. Brady filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K/A filed January 24, 2008 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.19.
10.20@	Offer Letter, dated as of July 27, 2009, between EnerNOC, Inc. and Timothy Weller, filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed July 31, 2009 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.20.

10.21@	Severance Agreement, dated as of July 27, 2009, by and between EnerNOC, Inc. and Timothy Weller, filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed July 31, 2009 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.21.
10.22@	Offer Letter, dated as of November 4, 2009, by and between EnerNOC, Inc. and Kevin Bligh, filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed November 10, 2009 (File No. 001-33471), is hereby incorporated by reference as Exhibit 10.22.
21.1*	Subsidiaries of EnerNOC, Inc.
23.1*	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
31.1*	Certification of Chief Executive Officer of EnerNOC, Inc. pursuant to Rule 13a-14(a) or Rule 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Accounting Officer of EnerNOC, Inc. pursuant to Rule 13a-14(a) or Rule 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of the Chief Executive Officer and Chief Accounting Officer of EnerNOC, Inc. pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101**	The following materials from EnerNOC, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012, formatted in XBRL (eXtensible Business Reporting Language); (i) Consolidated Balance Sheets as of December 31, 2012 and 2011, (ii) Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010, (iii) Consolidated Statements of Comprehensive (Loss) Income for the years ended December 31, 2012, 2011 and 2010, (iv) Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2012, 2011 and 2010, (v) Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010, and (vi) Notes to Consolidated Financial Statements.**

@ Management contract, compensatory plan or arrangement.

* Filed herewith

Portions of this Exhibit have been omitted and filed separately with the Securities and Exchange Commission as part of an application for confidential treatment pursuant to the Securities Act of 1933, as amended.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in Registration Statements on Form S-8 (Nos. 333-157980, 333-149939, 333-143906, 333-172533, and 333-180124) pertaining to the Amended and Restated 2003 Stock Option and Incentive Plan and the Amended and Restated 2007 Employee, Director and Consultant Stock Plan of EnerNOC, Inc., of our reports dated February 27, 2013, with respect to the consolidated financial statements of EnerNOC, Inc., and the effectiveness of internal control over financial reporting of EnerNOC, Inc. included in this Annual Report (Form 10-K) for the year ended December 31, 2012.

/s/ Ernst & Young LLP

Boston, Massachusetts
February 27, 2013

Exhibit 31.1

CERTIFICATIONS UNDER SECTION 302

I, Timothy G. Healy, certify that:

1. I have reviewed this annual report on Form 10-K of EnerNOC, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2013

/s/ TIMOTHY G. HEALY

Timothy G. Healy
Chairman of the Board and Chief Executive Officer

Exhibit 31.2

CERTIFICATIONS UNDER SECTION 302

I, Kevin J. Bligh, certify that:

1. I have reviewed this annual report on Form 10-K of EnerNOC, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2013

/s/ KEVIN J. BLIGH

Kevin J. Bligh
Chief Accounting Officer

Exhibit 32.1

CERTIFICATIONS UNDER SECTION 906

Pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code), each of the undersigned officers of EnerNOC, Inc., a Delaware corporation (the "Company"), does hereby certify, to such officer's knowledge, that:

The Annual Report for the year ended December 31, 2012 (the "Form 10-K") of the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 27, 2013

/s/ TIMOTHY G. HEALY

Timothy G. Healy
Chairman of the Board and
Chief Executive Officer

Dated: February 27, 2013

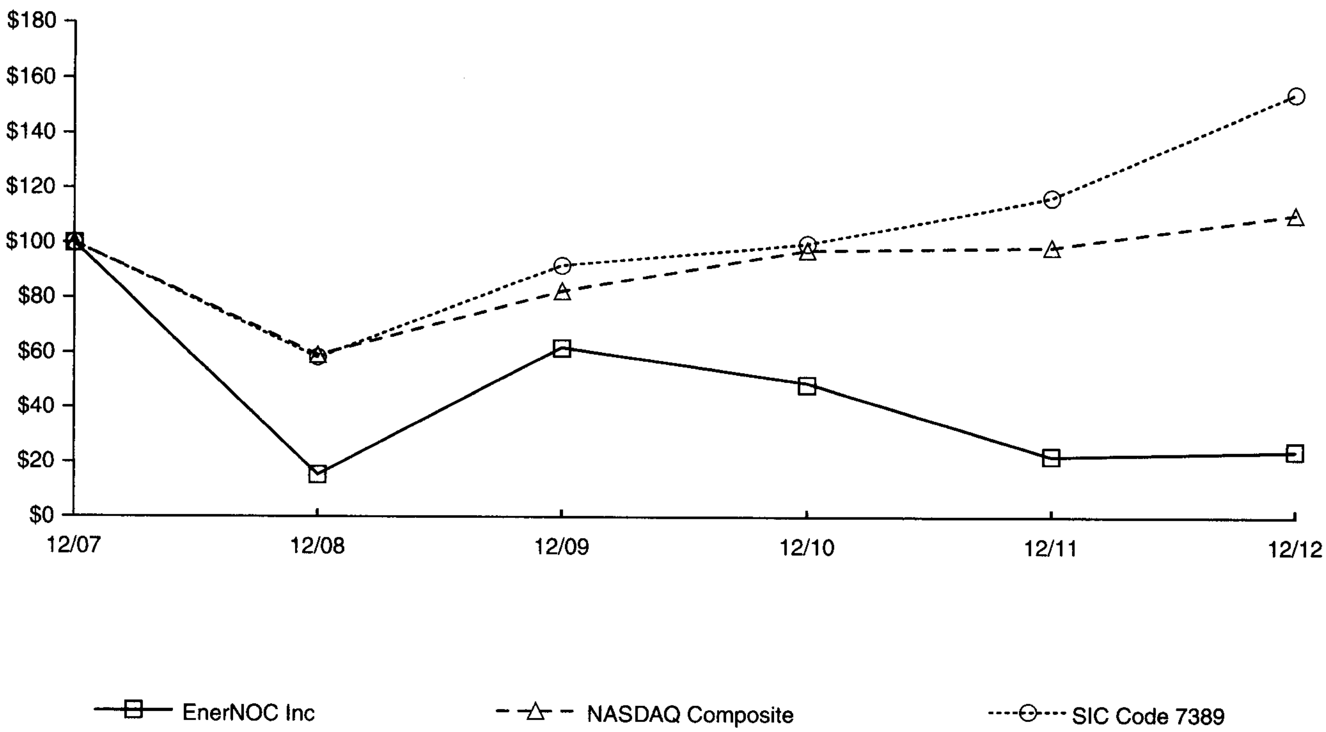
/s/ KEVIN J. BLIGH

Kevin J. Bligh
Chief Accounting Officer

The stock performance graph set forth below compares the cumulative total stockholder return on our common stock from December 31, 2007 through December 31, 2012 with cumulative total return of the NASDAQ Composite Index and the SIC Code 7389 Index over the same period.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among EnerNOC Inc, the NASDAQ Composite Index, and SIC Code 7389



* $100 invested on 12/31/07 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

1. This graph is not "soliciting material," is not deemed filed with the Securities and Exchange Commission and is not to be incorporated by reference in any filing of the Company under the Securities Act or the Exchange Act, whether made before or after the date hereof, except to the extent that the Company specifically incorporates this graph or a portion of it by reference.
2. The stock price performance of the Company shown on the graph is not necessarily indicative of future price performance.
3. Information used on the graph was obtained from Research Data Group, Inc., a source believed to be reliable, but the Company is not responsible for any errors or omissions in such information.
4. Our market capitalization as of December 31, 2012 was approximately $341.0 million.

EnerNOC, Inc. Headquarters
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Suite 1100
Boston, MA 02110
Office: 617.224.9900
Fax: 617.224.9910

www.enernoc.com

EnerNOC, Inc. is headquartered in Boston, MA, United States, with wholly-owned subsidiaries in Canada (EnerNOC Ltd.), the United Kingdom (EnerNOC UK Limited), New Zealand (EnerNOC New Zealand Limited), and Australia (EnerNOC Australia Pty Ltd, ACN 143 762 350). EnerNOC UK Limited is a company incorporated in England and Wales with company number 06937931, VAT number GB980145422 and whose registered office is located at Alder Castle, 4th Floor, 10 Noble Street, London EC2V 7JX. A list of directors is available for inspection at our offices.