TAB M-1-1

Overview

A. Landowner, Municipal and Community Consultation Plan

The Applicant is committed to open, transparent and meaningful consultations with affected landowners, municipalities and communities throughout the Project. To achieve this, the Applicant has assembled an experienced and highly skilled team to help carry out its community consultation plan in a way that fosters trust, communication and respect. The Applicant will reach out to all stakeholders to solicit their meaningful input before any decisions are made. Likewise, the Applicant will respond to all stakeholder questions and provide flexible and convenient opportunities to discuss the Project. To build respect among all concerned, the Applicant will document the consultation process, support the communities in the long-term and develop a strategy for resolving issues and evaluating the effectiveness of the consultation process. This strategy will include an issues and resolution tracking database throughout the lifecycle of the Project. The Applicant's Landowner, Municipality and Community Consultation Plan is included in Exhibit M-2-1. The Applicant will draw upon its experience in creating successful public engagement and consultation programs described previously in Exhibit E in finalizing the plan for the Project.

Proposed Consultation Process

After carefully reviewing and analyzing the circumstances, the Applicant intends to consult with everyone who owns or occupies property within the proposed construction zone, as well as residents within approximately 50 metres of the proposed ROW. The Applicant will also consult not only landowners, special interest groups, non-governmental organizations and agencies with an interest in the project, but also others who declare an interest in the project as the ToR and EA are developed. All affected townships and municipalities will also be consulted. Before construction on the project begins, all residents who might be affected and other interested stakeholders will be given the construction schedule and contact information for the Applicant's designated community liaison representative, who will take responsibility for maintaining positive relationships with the community and addressing all stakeholder concerns quickly and courteously. Every attempt will be made to encourage local or regional employment on the Project.

Along with the above, the Applicant plans to consult with the public throughout the Project by publishing notices of the Project's key stages, releasing notices to the media and sending letters and newsletters to landowners along the proposed route, relevant agencies, First Nation and Métis peoples and other interested parties. Issues workshops, interest group meetings and similar meetings at public information centres and other locations will be held to engage stakeholders in face-to-face dialogue on specific Project decisions. The Applicant intends to maintain round-the-clock access to information through a Project website, publicly posted and distributed project documents and a project telephone hotline. In addition, the Applicant will continuously monitor various social media throughout to determine whether and to what extent to augment delivery of accurate information and to receive stakeholder feedback.

The Applicant intends to be equally vigilant in consulting with interested agencies, starting with an Agency Consultation Package sent to all federal, provincial and municipal government stakeholder agencies and conservation authorities; the package will both inform and solicit comment. Throughout the Project development period, additional government and agency stakeholder communications are expected to request further involvement through meetings and other opportunities to provide feedback. Newsletters will be posted on the project website and sent to agency stakeholders and a Municipal Advisory Group ("**MAG**") will be formed if appropriate. Agencies, interest groups and municipal staff will be invited to a series of workshops to address topics such as route refinement, environmental assessment and mitigation of any effects.

For accountability, the Applicant will record and collate all consultation activities in the Record of Consultation database that will be included in the Consultation Appendix to the EA submitted to the Ontario Ministry of the Environment (the "**MOE**"). Through this database, the Applicant's team will be able to enter and track consultation events, such as phone calls, emails and face-to-face discussions with all parties. The database will also allow responses to be tracked, critical stakeholder issues to be identified and resolved and reports to be easily generated.

While consultations with different individuals and groups will flow freely throughout the Project, the Applicant also commits to the following key communications:

- Terms of Reference and Environmental Assessment under the *Environmental Assessment Act* in Q3 2013 – Q1 2016 and
- Permits/Approvals in Q3 2015 – Q2 2016.

Proposed Issue Identification and Resolution Process

The following chart briefly summarizes the Applicant's proposed strategy for resolving potential major issues that might arise during the Project.

ISSUE	DESCRIPTION	RESOLUTION STRATEGY
Recreation – fishing/hunting/trapping	A new line from Wawa to Thunder Bay will affect land currently used for recreation; a new line could also increase access to the relatively remote area.	The Applicant will keep communication channels with stakeholders open to ensure all recreational activities are identified and identify groups (such as snowmobile associations and outfitters) who use the area and can provide input; the project will be designed and implemented to minimize impact on recreation.
Natural Environment – terrestrial and aquatic habitat	Project may affect terrestrial and aquatic sites or species.	The Applicant will work closely with all stakeholders, particularly agencies, to design field programs that adequately determine baseline conditions. The predominant mitigation

ISSUE	DESCRIPTION	RESOLUTION STRATEGY
		strategy will be avoidance through, for example, alternative alignment that does not pass through the National Park. If potential impact is identified, mitigation strategies will be developed, with federal and provincial advice where appropriate.
Archaeological – heritage resources	Project might affect cultural resources.	The Applicant will work closely with all stakeholders, particularly relevant agencies and First Nation and Métis communities, to design field programs that adequately determine baseline conditions and use avoidance as the predominant mitigation strategy. First Nation and Métis employment during field surveys will be encouraged. Relevant authorities and appropriate First Nation and Métis communities will be contacted if archaeological artifacts or human remains are encountered.
Land Requirements	Land acquisition or easements might affect the Project schedule.	The Applicant has identified all land acquisition requirements; potential issues/resolution are separately identified.
Health Impact	Communities may fear that high-voltage transmission lines might negatively affect their health.	The Applicant will work with communities to site the project appropriately and provide plain language documentation addressing health risk misconceptions or concerns.

ISSUE	DESCRIPTION	RESOLUTION STRATEGY
Visual Impact	Additional infrastructure will change the viewshed.	The Applicant will work with communities to ensure that the project is sited appropriately and consider, for example, alternative alignments or placing towers parallel to existing towers.

B. First Nation and Métis Consultation Plan

To help the government meet its legal responsibility to consult with First Nation and Métis communities on proposed resource development projects, the Applicant has compiled a comprehensive First Nation and Métis Consultation Plan regarding the East-West Transmission Reinforcement Project. The First Nation and Métis Consultation Plan outlines how the Applicant proposes to build positive and long-lasting relationships with First Nation and Métis communities that the Project may affect and to effectively engage, consult and accommodate those communities. The Applicant’s First Nation and Métis Consultation Plan is included at Exhibit M-3-1.

The Applicant (which successfully completed similar consultations on two major electricity infrastructure projects in Ontario, the Greenwich Wind Farm and the Talbot Wind Farm) has assembled an experienced and skilled First Nation and Métis consultation team, including former Grand Council Chief John Beaucage as First Nation and Métis Special Advisor. The biography and resume of John Beaucage are included in Exhibit D-2-2. Guided by the Plan’s principles and core objectives, the consultation team will work closely with identified communities, organizations, companies and government representatives throughout the Project’s lifecycle.

Proposed Consultation Process

The Applicant's consultation strategy contemplates two-tiers for engaging with affected First Nation and Métis communities: pre-consultation and proactive relationship-building, beginning at the earliest possible planning stage, followed by meaningful consultation with all identified communities. The Applicant has already initiated efforts in the last year to build relationships with First Nation and Métis communities in connection with the Project, having contacted identified communities to inform them of the Applicant's intent to participate in the designation process and to seek their input in the First Nation and Métis Consultation Plan.

If selected, the Applicant will carry out meaningful consultation with affected communities applying the Consultation Plan's detailed approach. Recognizing that consultation is a flexible, evolving and collaborative process, the Applicant anticipates a range of consultation efforts with a wide array of opportunities to develop and modify the approach. Any corresponding and necessary accommodation identified through the consultation process will vary depending on the type of impact and the rights affected.

The list of First Nation and Métis Communities that have been identified as being potentially affected by the Project is included in Exhibit M-3-2.

The Applicant anticipates that communities that are signatories or adherents to the Robinson Superior and Robinson Huron Treaties of 1850 and Métis communities with historic connections to Lake Superior's north shore may also be interested in the Project. Throughout the consultation and environmental assessment processes, all affected communities will be engaged and any additional First Nation or Métis communities that might have an interest will be identified.

Proposed Issue Identification and Resolution Process

The following chart briefly summarizes the Applicant's proposed strategy for resolving potential major issues that might arise during the Project.

ISSUE	DESCRIPTION	MITIGATION STRATEGY
First Nation and Métis and Treaty Rights	A new line from Wawa to Thunder Bay will take up land used to exercise First Nation and Métis and Treaty Rights	The Applicant will consider numerous planning, construction and monitoring accommodation measures, such as Project employment. This will include reviewing the proposed route and seasonal construction activity and enhancing environmental monitoring
Exercise of Rights	A new transmission line may adversely affect a community's ability to exercise its rights	The Application will consider numerous measures to mitigate impact on the exercise of rights. Examples include avoiding activity on the land that affects key seasonal activity (hunting, gathering, trapping), working with communities to understand the effect on key sites of interest and working with communities to avoid or re-locate traditional activities
Health Impact	Communities may fear that high-voltage transmission lines might negatively affect their health (for example, increased cancer risk)	The Applicant will work with communities to provide plain language documentation that addresses health risk misconceptions or concerns and consider reviewing health monitoring, research and documentation
Moratoriums	Communities may be developing moratoriums on future development until outstanding land claims, treaty or other government-to-government issues are resolved	The Applicant will work closely with those communities to understand their concerns and actions' root causes and develop a range of accommodation or participation measures to address outstanding issues
Social Impact	Communities may fear that additional infrastructure will further erode their traditional	The Applicant will work with communities that concern and develop capacity-building

	way of life and negatively affect the communities' social or spiritual well-being or ultimately open opportunities for other development projects	initiatives to address the concerns, including creating elder documentation programs, sponsoring cultural and sporting events and supporting youth and education programming in the community

MOU with the Minister of Energy

Regarding the OEB's letter of December 11, 2012 (based on the Ministry of Energy's letter of November 26, 2012 to the Board), the Applicant is willing to enter into a MOU with the Ministry of Energy for the purpose of setting out respective roles and responsibilities of the Crown and the transmitter with respect to the Crown's Duty to Consult with First Nation and Métis Communities.

RES Transmission is familiar with this approach and has experience working with the Ministry of Energy where the Crown delegates certain procedural aspects of its consultation duty to a project proponent. Indeed, RES Transmission has already entered into MOUs for a similar purpose for what the Ministry of Energy refers to in its November 26 letter as "other significant electricity infrastructure projects". These MOUs entered into by RES Transmission are not dissimilar to the MOU on the public record in the application for LTC the Bruce to Milton transmission reinforcement project referenced in the Ministry of Energy's letter.

However, some aspects of the Bruce-Milton MOU signed between the Minister of Energy and Hydro One would not necessarily be applicable to RES Transmission. Unlike Hydro One, the Applicant is a private sector proponent and the MOU would need to be adjusted accordingly through negotiations between the Ministry of Energy and the designated transmitter. For instance, the Applicant suggests that the Consultation Plan forming part of this Application could form part of the MOU. Further, the Applicant suggests that it could be appropriate to list in the MOU the First Nation and Métis communities to be consulted as identified by the Ministry of Energy, with a proviso that others may be identified as the Project progresses

Conclusion

The Applicant is determined to implement the Project responsibly and respectfully so that the surrounding First Nation and Métis peoples, landowners, agencies and communities will embrace the Project. The ongoing and free-flowing communication the Applicant's community consultation plan proposes will achieve this by ensuring that the Applicant receives and responds to any community issues promptly and effectively.

TAB M-2-1

Landowner, Municipality and Community Consultation Plan

Renewable Energy Systems Americas Inc.

East West Transmission Reinforcement Project
Landowner, Municipal and Community Consultation Plan

Prepared by:

Stantec Consulting Ltd.
70 Southgate Drive, Unit 1
Guelph, ON N1G 3M5
Tel: (519) 836-6050

December 14, 2012

File No. 160960725

Record of Revisions

Revision	Date	Description
0	November 2012	Draft Provided to RES for Comment (electronic copy)
1	December 2012	Final Provided to RES

Table of Contents

1 CONTEXT FOR CONSULTATION

The Ontario Energy Board (OEB) has initiated a proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie line. The Board assigned File No. EB-2011-0140 to the designation proceeding.

The Board's primary objective in this proceeding is to select the most qualified transmission company to develop, and to bring a leave to construct application for, the East-West Tie line.

This Landowner, Municipal and Community Consultation Plan (Plan) was developed as part of the planning process for the East-West Tie, from Lakehead TS to Wawa TS (the Project). This Plan has been produced for The Applicant in support of their application for designation, consistent with the Ontario Energy Board requirements outlined in the Phase 1 Decision and Order (July 12, 2012).

The Applicant approaches the design and implementation of this Plan as a living document that will provide flexibility to parties to ensure the approach taken to develop positive relationships and fulfillment meets the latest direction set by Ontario and industry best practices. The Applicant has designed the Plan with the understanding that, as the possible designate, they are responsible for negotiating and implementing a wide array of consultation opportunities.

1.1 Consultation Team

The Applicant, in coordination with Stantec, has assembled an experienced and skilled Consultation team. Our team is prepared to work closely with landowners, municipalities and communities throughout the life of the Project.

2 CONSULTATION PLAN

2.1 Guiding Principles

Integrity and Good Faith – We will approach consultations with an open mind, conduct ourselves with integrity during the consultation process, and deal in good faith with all Project stakeholders. We will listen to and respond to concerns respecting potential impact and consider them when making decisions.

- **Respect** – Consultation will be undertaken in a spirit of mutual respect and trust. In addition, timelines will be reasonable and sensitive, while and recognizing the capacity needs of communities.
- **Flexibility, Transparency and Accountability** – The consultation processes will be flexible, transparent, accountable, timely, and results based. The Applicant will maintain detailed notes and records of all Consultation activities.
- **Communication** – Successful consultation depends on clear, open and honest communication. For example, technical information will be in plain language.

2.2 Objectives

The following core objectives are the basis of relationship building and consultation:

Ensuring outreach to interested Project stakeholders is accomplished by:

- Engaging with all potentially interested stakeholders in a user-friendly way;
- Providing opportunities for input throughout the Project stages and before decisions are made;

Ensuring trust is established and maintained through proactive relationship building during the lifecycle of the Project by:

- Providing appropriate, flexible and convenient opportunities for consultation that meets the needs of both The Applicant and communities;
- Being responsive;

Providing support, resources and advice that builds respect between the parties and adds value by:

- Documenting and tracking the consultation process;
- Providing long term support to communities;
- Providing an issues resolution strategy; and
- Evaluating the effectiveness of the program on an ongoing basis and making changes for improvement

3 IDENTIFICATION OF PARTIES TO BE CONSULTED

The EA Act s. 5.1 requires consultation to be undertaken during the preparation of an EA. There are a wide range of project interests and stakeholders. The following stakeholders will be consulted:

- Owners and occupants (tenants) of property within the proposed ROW;
- Residents within approximately 500 m of the proposed ROW;
- Non-government organizations and groups with an interest in the project;
- Agencies with an interest in the project including a Government Review Team;
- Townships/Municipalities affected by the project; and
- Others who declare an interest in the proposed undertaking during the ToR stage.

For information on First Nations and Métis consultation please refer to the separate Plan.

4 PLAN FOR CONSULTATION WITH EACH PARTY

4.1 Public Consultation

The following key consultation activities will be undertaken with the public:

Notices – Key Notices that will be published during the ToR/EA include:

- Notice of Commencement - letters to all landowners along the proposed route, agency and First Nations/Metis letters, contact lists, media releases (published twice in local newspapers).
- Five rounds of Notice of Public Information Centre (two during ToR and three during EA) - letters to all landowners along the proposed route, agency and First Nations/Metis letters, contact lists, media releases (each notice to be published twice in local newspapers).
- Notice of draft EA release for review - letters to all landowners along the proposed route, agency and First Nations/Metis letters, contact lists, media releases (published twice in local newspapers).
- Public Notice of Submission of EA to MOE – The Applicant will notify affected property owners and others on the mailing list that the EA document has been submitted to the Minister of the Environment for approval. The Notice will be published in local newspapers along the proposed route.

Newsletter – Newsletters will be produced at key decision points during the EA and construction stages of the project. Newsletters will be made available on the project web site (detailed below) and will be mailed to directly affected property owners. Four newsletters have been assumed.

Issues Workshops/Meetings – Workshops or meetings may be held as appropriate with property owners where environmental effects have been identified to provide updated information on the project, identify issues and discuss the property acquisition process.

Public Information Centers (PICs) – The purpose of the PICs will be to provide an opportunity for face-to-face discussion among affected property owners, interested individuals and the project team. Two sets of PICs will be held during the preparation of the ToR and three sets of PICs are anticipated during the EA process in each of the four locations (Thunder Bay, Nipigon, Marathon and Wawa). Key activities will include:

- Preparation and printing of materials (panels, questionnaire, sign-in sheets);
- Logistics coordination;
- Advertising/mailing;
- Attendance documentation; and
- Summary of all comments and questions received, issues tracking and draft responses.

Interest Group Meetings – If required, meetings will be held with key interest groups to identify issues and discuss options for resolution of issues at EA initiation and as issues arise during the EA process. Key activities include:

- Identifying relevant interest groups;
- Logistics coordination; and
- Meeting minutes and follow-up, if necessary.

Web Site – A project specific web site will be developed and used to continuously be updated throughout the project and will offer visitors the opportunity to comment.

Telephone Hot-Line – A project hot-line will be established to provide 24 hour voice mail access throughout the life of the project.

Documents Distributed and Posted in Public Places – Draft and final EA documents will be distributed to agencies, key interest groups, municipal officials and staff of affected communities. The Applicant will make documents available at local libraries and at municipal offices for review by members of the public. Documents will also be available for download from the project web site.

We will also monitor the Social Media throughout the EA process/construction/operation to determine if this avenue for communications is appropriate for the East-West Tie Project. If a social media strategy is undertaken, it will be developed in conjunction with the Applicant for maximum exposure with minimal effort.

4.2 Agency Consultation

The purpose of the agency consultation is to:

- Identify concerns and collect information related to the project;
- Discuss appropriate fieldwork methodologies;
- Identify issues related to the project, and where appropriate, propose mitigation;
- Facilitate the development of a list of all required approvals, licences or permits (and time lines);
- Identify relevant guidelines, policies and standards; and
- List all the commitments/obligations and responsibilities of the proponent.

Direct Mailing - Following the Notice of Commencement of the EA, an agency consultation package will be sent to all agency stakeholders from the federal, provincial and municipal governments and conservation authorities soliciting their input and feedback. Follow-up communications will occur with those agencies that request further meetings/involvement to discuss their input. Regular meetings are anticipated to discuss issues that arise. Agencies will also be notified when the draft EA is available for review.

Newsletter – Newsletters (as discussed above) will be made available on the project web site and will be mailed to all agency stakeholders.

Issues Workshops – Workshops may be held as appropriate with agencies, interest groups and municipal staff. These could address issues such as:

- Route Refinement; and
- EA Update, effects and mitigation.

Municipal Advisory Group (MAG) – A Municipal Advisory Group may be formed as necessary or if requested.

Notice of Submission of EA to MOE – The Applicant will notify agencies by mail that it has submitted the EA to the Minister of Environment for approval. Agency consultations will also dovetail with PIC events as avenues for further input to the process. Engagement with the various stakeholders is expected to be ongoing throughout the EA and into the project implementation process. All agency submissions and meetings will be documented and included in the Record of Consultation.

4.3 Record Tracking

All consultation activities and contacts will be detailed and collated in the Record of Consultation (ROC) database to be included in the consultation appendix for the EA submission to the MOE. Activities under this task will include:

- Maintaining contact lists;
- Preparation and maintenance of Consultation Manager™ database;
- Managing all correspondence received; and,
- Preparation of Consultation materials appendix.

The Consultation Manager™ database will allow all members of the team, regardless of geography, to enter and track consultation events, such as phone calls, emails, or face-to-face discussions. The software will also allow for real-time identification of critical stakeholder issues, so we can prioritize consultation initiatives, and minimize any potential surprises during the EA and permitting process.

5 SCHEDULE FOR CONSULTATION

Consultations are expected to move forward independently with each party and will be undertaken throughout key phases of Project planning, such as the ToR, EA and permitting/approvals. Key Milestones, in line with the overall Project schedule, are as follows:

Key Project Phase	Consultation Schedule
ToR/EA	Q3 2013 – Q1 2016
Permitting/Approvals	Q3 2015 – Q2 2016

The Applicant will continue its contact with project stakeholders during construction and operation of the Project for as long as this seems an effective two-way channel for communications. The Applicant will have a designated representative to maintain good community relations throughout the Project. The Project representative will address concerns expressed by stakeholders during construction in an expeditious and courteous manner. If required, an Issues Resolution Process will be developed. Prior to construction, all potentially affected residents will be provided with a contact telephone number for the community liaison representative and the general construction schedule. As a long-term presence in the community, The Applicant will continue to develop contacts and other local relationships and channels of communication, which could benefit the local area.

Ongoing stakeholder communication will allow The Applicant to receive and respond to community issues on an ongoing basis. The goal of the program is to be good corporate citizens, respect the natural and socio-economic environment, and enhance the quality of life in the communities in which The Applicant operates.

6 POTENTIALLY SIGNIFICANT ISSUES AND RESOLUTIONS

The following table presents an overview of anticipated issues landowners, municipalities, communities or agencies may raise during consultation including an overview of planned mitigation efforts.

ISSUE	DESCRIPTION	RESOLUTION STRATEGY
Recreation – fishing/hunting/trapping	A new line from Wawa to Thunder Bay will take up additional land that is currently being used for recreational purposes. A new line could also result in increased access to this relatively remote area.	The Applicant will maintain open channels of communication with stakeholders to ensure that all recreational activities are identified. The Applicant will also work with known stakeholders to identify those that use the area and can provide input, such as snowmobile associations and outfitters. The project will be designed, constructed and maintained in ways to minimize impacts to recreation.
Natural Environment – Terrestrial Habitat Aquatic Habitat	Particular issues may include impacts to terrestrial and aquatic designated sites or species.	The Applicant will work closely with all stakeholders, particularly relevant agencies, to ensure that field programs are designed to adequately determine baseline conditions. The predominant mitigation strategy will be avoidance, for example The Applicant has evaluated an alternative alignment which does not pass through the Pukaskwa National Park. Where potential impacts are identified appropriate mitigation strategies will be developed in line with federal and provincial recommendations, where appropriate.
Archaeology/Heritage Resources	Potential to impact cultural resources.	The Applicant will work closely with all stakeholders, particularly relevant agencies and First Nation and Metis communities, to ensure that field programs are designed to adequately determine baseline conditions. The predominant mitigation strategy will be avoidance. Should archaeological finds or human remains be encountered at any point in the process, The Applicant commits to contacting relevant authorities and appropriate Aboriginal communities.
Land Requirements	Potential impacts associated with land acquisition or easements.	The Applicant has identified all land acquisition requirements, any potential issues/resolutions will be fully identified and disclosed in the EA process.

ISSUE	DESCRIPTION	RESOLUTION STRATEGY
Health Impacts	Communities may be apprehensive that more high-voltage transmission lines could potentially have a negative impact on their health.	The Applicant will work with communities to site the project appropriately and provide them with all the necessary documentation, in plain language, that addresses facts about any potential impacts to health.
Visual Impacts	Additional infrastructure will change the viewshed	The Applicant will work with communities to ensure that the project is sited appropriately. For example, alternative alignments (route refinements) may be considered, or, where appropriate towers would be placed parallel to the existing towers of the Reference Route.

7 CLOSING

This Plan for the East-West Tie Project has been prepared by Stantec Consulting Ltd. for the sole benefit of The Applicant, and may not be used by any third party without the express written consent of the Applicant. The data presented in this report are in accordance with Stantec's understanding of the Project as it was presented at the time of reporting.

Respectfully submitted,
STANTEC CONSULTING LTD.

Written by:	Reviewed/Approved by:
	Peter Prier
Fiona Christiansen, M.Sc	**Peter Prier**
Senior Project Manager	Senior Principal, Energy & Environment, Environmental Services

rpt_60725_landowner-muni-and-comm-consult_20121214_fin.docx

TAB M-3-1

First Nation and Métis Consultation Plan

Renewable Energy Systems Americas Inc.

East-West Transmission Reinforcement Project
First Nation and Métis Consultation Plan

Prepared for:

Renewable Energy Systems Americas Inc.
11101 West 120th Avenue,
Suite 400 | Broomfield, CO 80021

Prepared by:

Stantec Consulting Ltd.
70 Southgate Drive, Unit 1
Guelph, ON N1G 3M5
Tel: (519) 836-6050

January 2, 2013
File No. 160960725

Record of Revisions

Revision	Date	Description
0	August 29 2012	Working Draft submitted to RES for discussion (electronic version)
1	September 28 2012	Draft submitted to RES for review and comments (electronic version)
2	January 02 2013	Final submitted to RES

Table of Contents

List of Appendices

1.0 INTRODUCTION

The Ontario Energy Board has initiated a proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie line. The Board assigned File No. EB-2011-0140 to the designation proceeding. The Board's primary objective in this proceeding is to select the most qualified transmission company to develop, and to bring a leave to construct application for, the East-West Tie line.

This First Nation and Métis Consultation Plan (Plan) was conducted as part of the planning process for the East-West Tie, from Lakehead TS to Wawa TS (the Project). This Plan has been produced for The Applicant in support of their application for designation. This Plan is consistent with the Ontario Energy Board requirements outlined in the Phase 1 Decision and Order (July 12, 2012).

2.0 CONTEXT OF DUTY TO CONSULT

Aboriginal rights, including Treaty rights, are recognized and protected under Section 35(1) of the *Constitution Act, 1982*. While Treaty rights are enshrined in agreements between the Crown and First Nations, Aboriginal rights reflect the fact that Aboriginal communities existed in North America prior to the arrival of Europeans. Aboriginal rights encompass the customs, practices and traditions that were an integral part of the distinctive cultures of these communities prior to their first contact with Europeans and which continue to have this significance in their cultures today. The most common Aboriginal rights are the rights to hunt, fish, trap and gather plants (for food, medicinal or cultural purposes).

The Courts have indicated that the exercise of rights is an evolving process and how the Crown fulfills their duty to consult and accommodate is also not static but a continual process of reconciliation. Common Aboriginal rights evolve with every court case and self-government agreement. The Applicant understands that the context of the duty to consult is evolutionary in nature and is not frozen in time. Flexibility is of upmost importance.

Provincial and federal governments have a duty to consult with Aboriginal communities whenever those governments propose a decision or activity that has the potential to adversely affect the ability of Aboriginal communities to exercise Treaty and Aboriginal rights and conduct traditional uses of lands and resources.

The Courts have determined that provincial or federal governments may delegate the procedural aspects of their legal duty to consult with Aboriginal communities to third parties. It is because of this power of delegation, that provincial and federal governments can require the proponents of resource development projects, including power transmission, to carry out the procedural aspects of the Crowns duty to Consult with Aboriginal Communities as part of a wide array of regulatory triggers prior to project approval, construction and operation.

The Ontario Power Authority (OPA) received a letter from the Ministry of Energy on May 31, 2011 delegating certain procedural aspects of consultation to the OPA with respect to the East-West Tie project.

The OPA's work in this regard involved:

- Discussing the East-West Tie project during Integrated Power System Plan (IPSP) regional sessions with First Nations
- Holding a teleconference session with Métis organizations
- Providing East-West Tie information to the relevant Aboriginal communities
- Taking feedback from Aboriginal communities into consideration in developing the East-West Tie Expansion report provided to the Ontario Energy Board (OEB).

The OPA confirmed that their role in discussions with Aboriginal Communities around project planning does not replace consultation requirements that may be required as transmitters proceed.

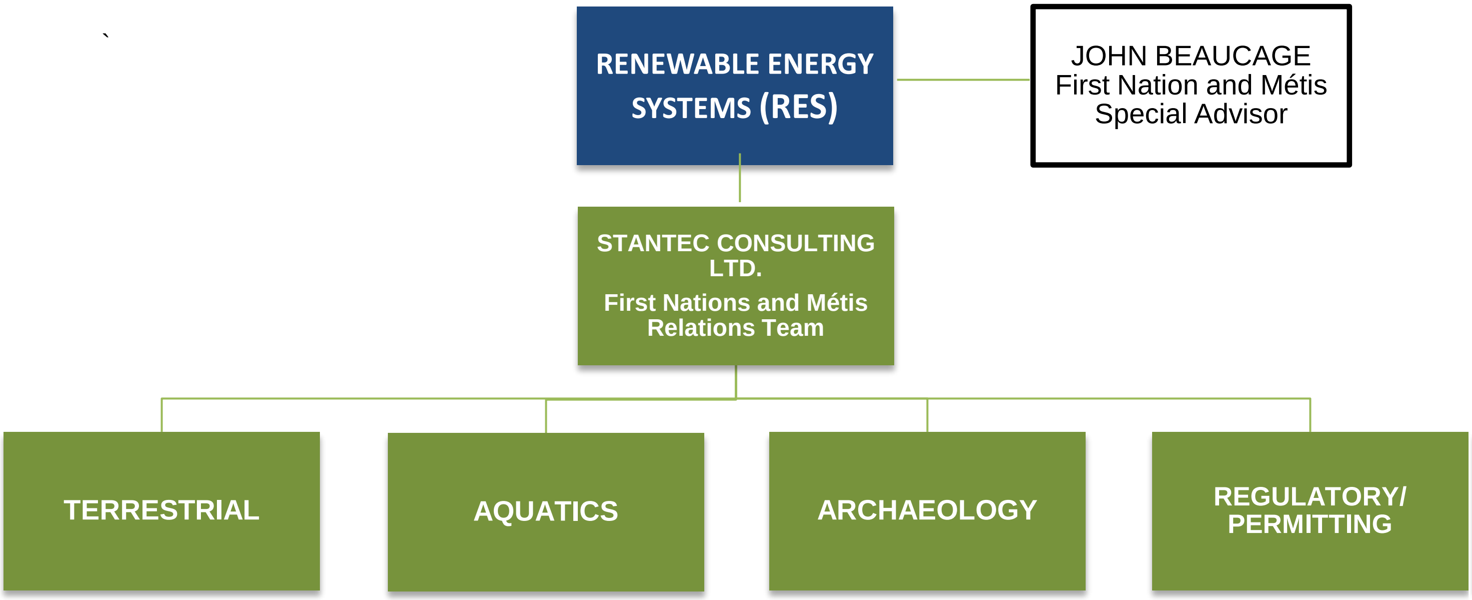
In a letter dated November 26th 2012 the Ministry of Energy and Infrastructure ("MEI") indicating that the procedural aspects of consultation are expected to be delegated to the designate though a memorandum of understanding ("MOU") to be executed between the MEI and the designate. The Applicant has compiled the following First Nations and Métis Consultation Plan ("the Plan") in order to outline how it proposes to carry out the procedural aspects of the Crown's Duty. Ultimately, the Crown must fulfill its legal obligations and The Applicant will work with Crown officials to ensure they have sufficient knowledge of the potential impacts and information on how The Applicant plans to accommodate the impact on traditional rights. The Plan outlines how The Applicant will build positive and long-lasting relationships, effectively engage, consult and potentially accommodate identified First Nations and Métis communities for the Project.

The Applicant approaches the design and implementation of the Plan as a living document that will provide flexibility to parties to ensure the approach taken to develop positive relationships and fulfillment of consultation obligations meets the latest requirements and industry best practices.

A stand-alone First Nation and Métis Participation Plan has also been prepared by The Applicant for the East-West Tie proposal.

3.0 PROJECT TEAM

The Applicant, in coordination with Stantec Consulting Ltd., and former Grand Council Chief John Beaucage, has assembled an experienced and skilled First Nations and Métis Consultation Team (see organizational chart below). Our team is prepared to work closely with First Nations and Métis communities, organizations, companies and Crown representatives throughout the lifecycle of the Project. Background information (CV's) for key team members are included elsewhere in the application.



4.0 OVERVIEW OF RELATIONSHIP BUILDING/PRE-CONSULTATION AND CONSULTATION

Relationship Building and Pre-Consultation

The Applicant is seeking positive, long-lasting and personal relationships with First Nations and Métis communities well before the Crown's regulatory requirements to Consult and Accommodate are triggered. Relationship Building and Pre-Consultation sets the overall framework in which we learn about the history and culture of specific communities, their relationship with the land and how they envision their participation in the Project and any potential impact the Project will have on traditional rights. We understand the value of building relationships with local communities and maintaining those relationships.

Relationship Building may not be tied to any specific component of the Project. The Applicant may visit communities and proactively request informational presentations about local culture or seek targeted discussions with Aboriginally-owned company representatives, in order to get a better understanding of the possible business opportunities if The Applicant is designated as the transmitter. Relationship Building is an ongoing dialogue opportunity throughout the life of the Project.

The Applicant is currently maintaining a Pre-Consultation Engagement Log. This Log lists the names, contact information and dates of correspondence with communities to date. As of the date of compiling this report the Log included correspondence with 18 communities from July to November 2012. Follow-up meetings have been offered to all communities. In some instances, due to the pre-existing arrangements in place between Bumkashwada and EWT LP, a meeting was refused on grounds of non-disclosure requirements. In other cases communities indicated they preferred discussing with the ultimate designate but appreciated the outreach. A copy of the consultation log is included in **Appendix A**.

Consultation

The Applicant is willing to enter into a memorandum of understanding (MOU) with the Ministry of Energy for the purpose of setting out respective roles and responsibilities of the Crown and the transmitter with respect to the Crown's Duty to Consult with Aboriginal Communities. Our First Nation and Métis team will work closely with the Crown in order to ensure consultation and accommodation efforts are sufficient. We look forward to sharing our Pre-Consultation engagement with the Crown in order to confirm roles and responsibilities, scope, timelines and finalizing an accurate list of First Nations and Métis communities to be consulted.

Through information gathered in our Pre-Consultation engagements and The Applicants experience with First Nation Consultation and Accommodation in Ontario, we anticipate and plan that the Project will require a range of consultation efforts, with several First Nation and Métis communities, including funding arrangements for capacity building within identified communities.

For consultation to be meaningful, efforts will be made to incorporate the community's knowledge, referred to as Traditional Ecological Knowledge, and advice into the Project Plan. First Nation and Métis communities expect that the designated transmitter brings meaningful consultation to the table. In order to implement the effective and meaningful Consultation, The Applicant is willing to share ideas with communities; and to understand what they consider meaningful. In many cases, it is expected meaningful consultation to begin at the project planning stage (i.e., mapping transmission routes, determining project location). Communities are often not satisfied with simply providing the Consultation Team with an opinion on the Project Plan; they are looking to help develop the Plan, particularly on projects within their traditional territory, and expect the designated transmitter will utilize their traditional knowledge in meaningful ways.

We anticipate consultation and accommodation will be an evolving process. First Nations and Métis communities expect consultation to begin at the earliest possible planning stage and continue throughout the Project's lifecycle.

5.0 CONSULTATION PLAN FOR FIRST NATIONS AND MÉTIS

In order to ensure that consultation and accommodation with First Nations and Métis communities are met, and the Honour of the Crown is upheld, our Plan will be guided by the following Consultation Principles:

5.1 Guiding Principles of First Nations and Métis Consultation Plan

- **Integrity and Good Faith** – the duty to consult is the ultimate responsibility of the Crown. We will approach delegated procedural aspects of consultations with an open mind, conduct ourselves with integrity during consultation and accommodation processes and deal in good faith with First Nations and Métis communities. We will listen to and respond to concerns respecting potential impact on constitutionally protected rights.
- **Respect** – The process to meet the delegated procedural aspects of consultation will be undertaken in a spirit of mutual respect and trust. For example, cultural practices will be respected and traditional knowledge will be taken into consideration that demonstrates respect to their lawful owners. In addition, timelines will be reasonable, sensitive and will recognize the capacity needs of the communities.
- **Flexibility, Transparency and Accountability** – First Nations and Métis communities will require a tailored and flexible approach to consultation. The consultation processes will be flexible, transparent, accountable, timely and results based. The Applicant will maintain detailed notes and records of Pre-Consultation, Consultation and Accommodation activities and implementation plans for the Crown to review.
- **Communication** – Successful consultation depends on clear, open and honest communication between the Crown, The Applicant, First Nations and Métis communities with potentially impacted rights. For example, technical information will be in plain language and translated if applicable.

5.2 Objectives of the Plan

The following core objectives are the basis of relationship building/pre-consultation and consultation:

Ensuring regulatory requirements are met;

- Consult with all potentially affected and interested First Nation and Métis communities;
- Provide various opportunities for input throughout the planning stages and before decisions are made; and
- Ensure The Applicant’s actions are cognizant of the fact that First Nation and Métis consultation is unique in being a constitutional obligation on the Crown, certain aspects of which may be delegated to the designated transmitter.

Ensuring trust is established and maintained through proactive Relationship Building during the lifecycle of the Project;

- Provide appropriate, flexible and convenient opportunities for engagement that meets the needs of both The Applicant, the communities and if needed the Crown;
- Be responsive;
- Anticipate that capacity building will be required to provide feedback and advice from First Nations and Métis and additional time and resources may be required; and
- Demonstrate to the Crown that The Applicant's actions meet the requirements to conduct consultations with First Nation and Métis communities on behalf of the Crown.

Providing support, resources and advice that builds respect between the parties and adds value;

- Document the consultation process;
- Provide long term support to First Nation and Métis communities;
- Provide concrete solutions to resolve any issues; and
- Evaluate the effectiveness of the program on an ongoing basis and make changes for improvement when required

5.3 Identification of First Nation and Métis Communities

As part of Pre-Consultation efforts, The Applicant has notified the following communities that have been identified by the Minister of Energy of The Applicant's intention to participate in the Boards Designation process.

First Nation Communities

1. Animbiigoo Zaagi'igan Anishinaabek First Nation (Lake Nipigon Ojibway)
2. Biinjitiwaabik Zaaging Anishinaabek First Nation (Rocky Bay)
3. Bingwi Neyaashi Anishinaabek (Sand Point First Nation)
4. Fort William First Nation
5. Ginoogaming First Nation
6. Long Lake No.58 First Nation
7. Michipicoten First Nation
8. Missanabie Cree First Nation
9. Ojibways of Batchewana
10. Ojibways of Garden River
11. Ojibways of Pic River (Heron Bay First Nation)
12. Pays Plat First Nation
13. Pic Mobert First Nation
14. Red Rock Indian Band

Métis Communities

1. Greenstone Métis Council
2. Superior North Shore Métis
3. Thunder Bay Métis
4. Red Sky Independent Métis Nation

Through The Applicant's previous consultation experience in the region, it has also identified the Kiashke Zaaging Anishinaabek (Gull Bay First Nation) as a community with possible interest in the project. This identified possible interest is based on the community's geographic location and status as signatory to the Robinson-Superior Treaty.

The Applicant anticipates interest in the Project coming from First Nation communities that are signatories or adherent to the Robinson Superior Treaty of 1850 and the Robinson Huron Treaty of 1850. The Applicant also anticipates interest coming from Métis communities with historic connections to the north shore of Lake Superior where they continue to exercise their rights.

The Applicant anticipates developing Consultation and Participation relationships with a number of the First Nation and Métis communities along the proposed line and identified by the MEI.

A complete profile of each First Nation and Métis community, including contact information, is provided in **Appendix B**.

6.0 APPROACH TO ENGAGING FIRST NATIONS AND MÉTIS

The Applicant is proposing the following two-tiered approach for engaging with affected First Nations and Métis communities, along with rationale or other justification for such an approach.

Relationship Building/Pre-Consultation

The Applicant recognizes that building relationships is an ongoing dialogue opportunity that can identify issues addressed through consultation and accommodation or participation priorities well before formal proceedings are triggered.

For these reasons, The Applicant has been and will be proactively seeking positive, long-lasting and personal relationships with First Nations and Métis communities at a very early stage in Project planning.

The Applicant believes conducting Pre-Consultation efforts, through relationship-building initiatives is the most effective way of accomplishing the key goals of the Plan.

- Strong relationships will aid in addressing key challenges such as input into consultation activities (data sharing).
- The relationship-building undertaken in Pre-Consultation can lessen these challenges by ensuring the parties have appropriate contacts within the project team and knowledge of the Project.
- Pre-Consultation will also directly inform how The Applicant will develop and implement a more focused Consultation and Accommodation strategy.

Consultation

The Applicant will undertake the delegated aspects of consultation with First Nation and Métis communities which may be adversely affected by the Project as will be defined in the MOU executed with the MEI. Meaningful consultation will not be static but will be an evolving, reconciliation process, in which regulatory requirements are met; sufficient accommodation measures will be implemented to avoid, mitigate or compensate for adverse effects on the exercise of rights; and the Honour of the Crown is upheld.

The Applicant anticipates the level of consultation, and corresponding accommodation, will vary depending on the type of impact and the nature of the rights being affected. The Applicant will gather information of key community issues through its Pre-Consultation work.

We believe this approach to conducting consultation and accommodation efforts is the best course of action.

The proposed consultation is an effective, flexible, scalable, responsive and efficient way to accomplish the key goals of the Plan:

- The consultation plan ensures regulatory requirements are met;
- It ensures trust is established and maintained throughout the lifecycle of the Project; and
- It provides support, resources and advice that build respect between the parties.

Participation

The participation of First Nations or Métis in business opportunities is expected to have a significant positive impact on the overall relationship between The Applicant and First Nations and Métis communities and are closely related to treaty issues, land use issues, and permitting.

The Applicant has developed a separate document that addresses potential First Nation and Métis economic participation in the Project.

7.0 SIGNIFICANT FIRST NATION AND MÉTIS ISSUES

We have developed an overview of anticipated issues First Nations or Métis communities may raise in pre-consultation or consultation including an overview of planned mitigation efforts.

ISSUE	DESCRIPTION	MITIGATION STRATEGY
Taking up of Lands	A new line from Wawa to Thunder Bay (approximately 400 km) Will take up additional land that is currently being used to exercise Aboriginal and Treaty Rights	The Applicant will consider a wide array of planning, construction and monitoring accommodation measures. Accommodation includes review of proposed route, review of seasonal construction activity; review of enhanced environmental monitoring.
Exercise of Rights Impacted	A new transmission line will adversely affect a community's ability to exercise their rights.	The Applicant will consider a wide array of accommodation to mitigate impacts on the exercise of rights. Examples include activity on the land will avoid key seasonal activity (hunting, gathering, trapping); working with communities to understand the impacts and avoid key sites of interest; work with communities to re-establish or re-locate traditional activities away from the proposed transmission route.
Health Impacts	Communities may be apprehensive that more high-voltage transmission lines would have a negative impact on their health (e.g. greater risk of cancers, impacts on fish, wildlife ect…).	The Applicant will work with communities to provide them with all the necessary documentation, in plain language, that addresses misconceptions or concerns about impacts to health; review of health monitoring, research and documentation.
Moratoriums	Communities may be developing moratoriums on future development until outstanding land claim, treaty or other government-to-government issues are resolved.	The Applicant will work closely with those communities advancing moratoriums to understand their concerns, the root causes of their actions and develop a wide array of accommodation or participation measures that may address outstanding issues.
Social Impacts	Communities may have concerns that additional infrastructure may lead to a further erosion of a traditional way of life and negative impacts on community members social or spiritual well-being. and A new transmission line may ultimately open up opportunities for other projects to be developed in the area	The Applicant will work with communities that express a concern about impacts on culture and develop capacity building initiatives that address this concern including: elder documentation programs, sponsorship of cultural events, sponsorship of sporting events, and support for youth and education programming in the community.

8.0 METHOD AND SCHEDULE FOR RELATIONSHIP BUILDING/PRE-CONSULTATION AND CONSULTATION

8.1 Methods of Relationship Building/Pre-Consultation

We propose to initiate Relationship Building and Pre-Consultation through a series of:

- Letters
- telephone call follow-ups
- faxes
- emails
- meetings at key local, regional and national gatherings
- workshops and
- other multi-media.

Investing time at the beginning of a relationship helps to establish a good foundation for the entire relationship-building process. We know that this “front heavy” approach takes time and effort at the beginning, but once a good relationship is established, the work required for maintaining relationships is greatly reduced. Established relationships increase the efficacy of consultation, resulting in time efficiencies for The Applicant and the communities

We will reach out to the identified First Nations and Métis leaders and elders and learn about the history and culture of specific communities, their relationship with the land and how they envision their involvement in the Project. Pre-Consultation and Consultation will require coordination with the Crown and communities

Pre-Consultation will likely require some capacity building for First Nations and Métis communities to engage in a meaningful way. In addition to Pre-Consultation capacity building (e.g. travel, accommodation, meals, elders’ honorariums etc…), The Applicant will consider supporting community sport and cultural events such as hockey tournaments, powwows, documenting and archiving elders.

If invited, The Applicant will attend social gatherings and community functions to aid in the relationship-building process, particularly with those First Nation and Métis communities that require the highest levels of consultation or which capabilities and interest would lead to participation opportunities.

8.2 Methods of Consultation

Providing Notice

Consultation and engagement with First Nation and Métis communities will provide project related information in an easily accessible and understandable format. Notification will be provided in writing to the leadership in the First Nations and Métis communities that may potentially be affected by the Project. Notification will be as early as possible and in advance of decisions.

Notification will provide clear, complete and understandable information and will include the following:

- Description of the decision or action that The Applicant is contemplating
- The extent and likely duration of the impact
- Specific questions about the information being requested (such as traditional ecological knowledge, archaeological sites, sacred sites and burial grounds and comments on fieldwork methodologies)
- Identification of timeline for response
- Assessment of likely impact on the environment
- Identification of any mechanisms that will be applied to mitigate

The team will utilize the following methods of communication:

- Mail/E-mail
- Newspaper Advertisement **–** If applicable within the community
- Web Site – The web site will continue to be updated throughout the project and will offer visitors the opportunity to comment.
- Telephone Hot-Line – The project hot-line will provide 24 hour voice mail access throughout the life of the project.
- Meetings – Staff, Community Members and Chief/Council
- Workshops
- Documents Distributed and Posted in Public Places – documents will be distributed to communities. The Applicant will make documents available at local libraries/heritage centers/economic development offices. Documents will also be available for download from the project web site.

Funding/Capacity Building

The Applicant anticipates the capacity to engage in a meaningful way will vary among communities. The Applicant will consider capacity building options for consultation including the incorporation of First Nation and Métis traditional and ecological knowledge and advice into the Project plan. Capacity building may also be used to build skills within First Nation and Métis communities that can be transferred to other projects in the future. As an example, we could offer sponsorship to videotape elders in order to record history of the traditional territory and traditional values in their native language. These video tapes can then be owned and used by the communities.

We are prepared to share ideas with First Nations and Métis communities; and to incorporate feedback and knowledge in a meaningful way into the Project plans on an ongoing basis. The Applicant anticipates requests for capacity building to focus on:

- independent review of environmental impact assessments/technical studies,
- travel, hospitality and accommodation to attend meetings,
- honorariums for Elders to open/close formal meetings,
- capacity to research and design alternative mitigation models.

Information Exchange/Considering the Response

The content of the responses from First Nation and Métis communities may affect the timelines for decision making. Consultation may result in new information being identified and may elevate the level of consultation required or time needed to incorporate the information into modified plans and proposals.

Where applicable, The Applicant will engage with relevant consultation protocol agreements. The aim of this engagement will be to determine the context of what will be expected in terms of consultation requirements for each community. The Applicant will work closely with the Crown to confirm the level of consultation and potential accommodation required. Flexible, scalable consultation agreement that fits the unique circumstances of individual First Nations and Métis communities will be crucial for the overall success of the consultation process. Likewise, accommodation will need to be tailored to meet the specific requirements of the community.

Assessing Affects

We will work with First Nation and Métis representatives to understand how the Project might affect rights, culture and way of life. We will work with communities throughout the entire life of the project (preparation of EA Terms of Reference, EA Process, Permitting/Approvals, Detailed Design, Construction, Operation and Maintenance). Specific questions will be raised such as:

- Identify the Treaty or Aboriginal Right that is being exercised in the area;
- Identify the type of Treaty or Aboriginal Right that would be impacted by the project;
- Identify in what way the identified Right would be impacted (e.g. permanently removed opportunity, temporary removal during a phase of the project, seasonal disruption etc…);
- Identify the importance placed on the Right that may be impacted (e.g. integral part of the community, peripheral use etc…)
- Identify impacts on traditional life and map out interests where applicable.

- Identify interests that may not be rights, and how the Project would impact them.

Once a comprehensive and clear understanding of the potential effects on rights is established, we will develop a matrix model that analyses the rights being impacted, how deeply the impacts would be and recommend an appropriate accommodation strategy.

Accommodating

Accommodation means we will use what was learned about affects to rights during the consultation process to minimize or avert the adverse effects by avoiding, changing or amending the Plan. Accommodation, like consultation, occurs on a spectrum. Individual communities will require a tailored accommodation approach that meets their unique circumstances.

Examples include:

- alternate transmission line routes (route refinement areas),
- removal or safeguarding of archaeological artifacts,
- avoiding sacred sites, burial grounds or zones of high sensitivity to the community,
- funding for cultural or linguistic programming,
- upgrades or construction of water facilities,
- upgrades or construction of community and transmission access roads
- funding for community training and apprenticeship programs

The Applicant also understands that the use of Impact Benefits Agreements may be required by First Nation and Métis communities. The Applicant anticipates these requests and opportunities and has developed a separate First Nation and Métis Participation Plan document that outlines this strategy.

Ongoing Presence

We are committed to continuing contact with First Nation and Métis communities during operation of the Project for as long as this seems an effective two-way channel for communication. We will be responsible for addressing concerns expressed by First Nations and Métis communities in an expeditious and courteous manner. Prior to construction, all potentially affected communities will be provided with contact information and the general schedule of the Project. The Applicant anticipates a long-term presence in the communities; The Applicant will continue to develop contacts and other local relationships and channels of communication, which could benefit the local area.

8.3 Schedule

Pre-Consultation and Consultation are expected to move forward independently with each First Nation and Métis community and will be undertaken throughout the key project phases: Terms of Reference (TOR) preparation, Environmental Assessment/Permitting, Design, Construction and Maintenance/Operation.

Pre-Consultation (early planning stages + pre-TOR planning)

Investing time at the beginning of a relationship helps to establish a good foundation for the entire Project. We acknowledge this component is “front heavy” and takes times and effort at the beginning, but once a good relationship is established, the work required for maintaining relationships is greatly reduced.

We are committed to initiating relationship building exercises early, prior to drafting ToR for the Project and continue in relationship building opportunities throughout each stage of the Project.

Consultation (all phases of the project that trigger Decisions – TOR preparation, EA/Permitting, Design, Construction Permitting and Maintenance/Operation Permitting)

The regulatory requirements to consult and accommodate will be triggered as the Project moves through different phases. Within this process, there will be independent engagement opportunities for gathering information, analyzing environmental and technical data and providing the information required to inform the overall consultation process and develop an appropriate Accommodation Strategy for each affected First Nation and Métis community.

9.0 CLOSING

This First Nations and Métis Consultation Plan for the East-West Tie Project has been prepared by Stantec Consulting Ltd. for the sole benefit of The Applicant, and may not be used by any third party without the express written consent of The Applicant. The data presented in this report are in accordance with Stantec's understanding of the Project as it was presented at the time of reporting.

Respectfully submitted,
STANTEC CONSULTING LTD.

Written by:	Reviewed/Approved by:
Herb Shields, MA	Fiona Christiansen, M.Sc
Aboriginal Relations Specialist	Senior Project Manager

w:\active\60960725\reports\aboriginal consultation and participation\pro_60725_res_aboriginal_consult_plan_20130102_fin.docx

Appendix A

First Nations and Métis Engagement Log

First Nation and Métis Engagement Log – East West Tie Line designation process

Last Updated:
November 9th 2012

Item #	Date	Organization/ Department	Contact Name(s)	Title	Contact Information	Note
1.	May 2nd 2012	Fort Williams First Nation	Ian Bannon Edmond Colins	n/a	90 Anemki Dr., Suite 200, Thunder Bay, ON, P7C 4Z2	• RES Transmission met with Fort Williams First Nation contacts to explain RES Transmission potential involvement in upcoming EWTL designation process. • RES Transmission presented company and brief overview of planned activities for the designation and development of the EWTL.
2.	May 3rd 2012	Odjibways of Pic River	Chief Roy Michano	Chief	PO Box 193 Heron Bay ON P0T 1R0	• RES Transmission met with Pic River Chief to explain RES Transmission potential involvement in upcoming EWTL designation process. • RES Transmission presented company and brief overview of planned activities for the designation and development of the EWTL.
3.	May 3rd 2012	Michipicoten First Nation	n/a	n/a	RR1, PO Box 1, Site 8, Wawa, ON, P0S 1K0	• RES Transmission dropped in Michipicoten First Nation to provide RES Transmission company brochures and basic company information, no meeting was held with representatives as none were available.
4.	May 3rd 2012	Red Rock	n/a	n/a	PO Box 1030, 2 Main St. Lake, Helen Reserve Nipigon ON P0T 2J0	• RES Transmission dropped in Red Rock First Nation to provide RES Transmission company brochures and basic company information, no meeting was held with representatives as none were available.
5.	July 18th, 2012	Fort Williams First Nation	Chief Peter Collins	Chief	90 Anemki Dr., Suite 200, Thunder Bay, ON, P7C 4Z2	• RES Transmission invited Chief Collins to discuss potential First Nations engagement for the

						development plan for the EWTL designation process. • Due to the non-disclosure agreement in place between Bumkashwada and EWT LP the meeting was refused on grounds of non-disclosure requirements.
6.	July 18th, 2012	Michipicoten First Nation	Chief Joe Buckell	Chief	RR1, PO Box 1, Site 8, Wawa, ON, P0S 1K0	• RES Transmission invited Chief Buckell to discuss potential First Nations engagement for the development plan for the EWTL designation process. • Due to the non-disclosure agreement in place between Bumkashwada and EWT LP the meeting was refused on grounds of non-disclosure requirements.
7.	July 18th, 2012	Pays Plat First Nations	Chief Xavier Thompson	Chief	10 Central Place Pays Plat ON P0T 3C0	• RES Transmission invited Chief Thompson to discuss potential First Nations engagement for the development plan for the EWTL designation process. • Due to the non-disclosure agreement in place between Bumkashwada and EWT LP the meeting was refused on grounds of non-disclosure requirements.
8.	August 9th 2012	Fort Williams First Nation	Chief Peter Collins	Chief	90 Anemki Dr., Suite 200 Thunder Bay ON P7C 4Z2	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
9.	August 9th 2012	Michipicoten First Nation	Chief Joe Buckell	Chief	RR1, PO Box 1, Site 8 Wawa ON P0S 1K0	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the

						OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
10.	August 9th 2012	Odjibways of Pic River	Chief Roy Michano	Chief	PO Box 193 Heron Bay ON P0T 1R0	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
11.	August 9th 2012	Pays Plat First Nations	Chief Xavier Thompson	Chief	10 Central Place Pays Plat ON P0T 3C0	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
12.	August 9th 2012	Pic Mobert First Nation	Chief Johanna Desmoulin	Chief	PO Box 717 Mobert ON P0M 2J0	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies

						• Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
13.	August 9th 2012	Red Rock Indian Band	Chief Arlene Wawia	Chief	PO Box 1030, 2 Main St. Lake, Helen Reserve Nipigon ON P0T 2J0	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
14.	September 10th 2012	Métis Nation of Ontario (MNO)	Jason Taylor Maden (legal) and Cameron Burgess	Legal and Chair of Consultation Committee		• Meeting was held at Jason Taylor Maden Law office in Toronto between MNO representatives and RES Transmission • Lunch followed
15.	September 13th 2012	Métis Nation of Ontario (MNO)	Jason Taylor Madden (legal) and Cameron Burgess	Legal and Chair of Consultation Committee		• Follow up e-mail was sent requesting one-pager to initiate consultation framework discussions
16.	September 27th 2012	Animbiigoo Zaagi'igan Anishinaabek First Nation (Lake Nipigon Ojibway)	Chief Yvette Metansinine	Chief	PO Box 120, Beardmore, ON, P0T 1G0	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
17.	September 27th 2012	Biinjitiwabik Zaaging Anishnabek First Nation (Rocky Bay)	Chief Velda Lesperance	Chief	General Delivery, Macdiarmid, ON, P0T 2B0	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns

						including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
18.	September 27th 2012	Bingwi Neyaashi Anishinaabek (Sand Point) First Nation	Chief Paul Gladu	Chief	146 Court Street South, Thunder Bay, ON, P7B 2X6	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
19.	September 27th 2012	Ginoogaming First Nation	Chief Ceila Echum	Chief	PO Box 89, Long Lac, ON, P0T 2A0	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
20.	September 27th 2012	Long Lake No. 58 First nation	Chief Allen Towegishig	Chief	PO Box 609, Long Lac, ON, P0T 2A0	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
21.	September	Missanabie Cree First	Chief Kim Rainville	Chief	174B highway 17 East, Bells	• RES Transmission sent out letter, by

	27th 2012	Nation			Point, Garden River, ON, P6A6Z1	e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
22.	September 27th 2012	Ojibways of Batchewana	Chief Dean Sayers	Chief	236 Frontenac Street, Sault Ste Marie, ON, P6A 5K9	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
23.	September 27th 2012	Ojibways of Garden River	Chief Lyle Sayers	Chief	RR4, 7 Shingwauk Street, Graden River, ON, P6A 6Z8	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
24.	September 27th 2012	Kiashke Zaaging Anishinaabek (Gull Bay First Nation)	Chief Miles Nowegejick	Chief	188 General Delivery, Gull Bay, ON, P0T 1P0	• RES Transmission sent out letter, by e-mail and regular mail, informing First Nations of participation in the OEB designation process for the EWTL. • Request was made to meet in order to discuss potential concerns

						including treaty rights, potential impacts and mitigation strategies • Follow up meetings were offered in forum deemed most appropriate to First Nations peoples.
25.	October 3rd 2012	Bingwi Neyaashi Anishinaabek (Sand Point) First Nation	Jordan Hatton	Director of Lands and Resources	jhatton@shawbiz.ca Phone: 807-623-2724 Fax: 807-623-2764 Cell: 807-472-9619	• Received e-mail from the Bingwi Neyaashi Anishinaabek (Sand Point) First Nation indicating support for the Project. • E-mail indicated that verbal agreements between the Bingwi Neyaashi Anishinaabek (Sand Point) First Nation and Red Rock Indian Band and Pays Plat First Nation indicate that Red Rock Indian Band and Pays Plat First Nation should be approached.
26.	October 11th 2012	Métis Nation of Ontario (MNO)	Jason Taylor Madden (legal) and Cameron Burgess	Legal and Chair of Consultation Committee	Jason@jtmlaw.ca cameronb@metisnation.org	• Follow up e-mail requesting follow up call or meeting from September meeting.
27.	October 22nd 2012	Ojibways of Garden River	Chief Lyle Sayers	Chief	RR4, 7 Shingwauk Street, Graden River, ON, P6A 6Z8	• Received letter from Ojibways of Garden River in response to September introduction letter • Ojibways of Garden River expressed support for the project and appreciates RES Transmission outreach. • Indicated interest in partnering in the economic development in the area.

Appendix B

First Nation and Métis Community Profiles

Official Name	Fort William
Number	187
Address	90 ANEMKI DRIVE, SUITE 200, THUNDER BAY, ON
Postal code	P7J 1L3
Phone	(807) 623-9543
Fax	(807) 623-5190
Website	http://www.fwfn.com/
Chief	Chief Peter Collins
Total Registered Population	2,077
Note	Fort William First Nation has identified RES Wind and the East-West Tie Transmission Project as Economic Development opportunities. Member of the Bamkushwada limited partnership. Significant potential impacts on how to develop a positive relationship given existing expectations and commitments with other parties. Anticipate deep consultation and accommodation process.

Official Name	Red Rock
Number	193
Address	PO BOX 1030, NIPIGON, ON
Postal code	P0T 2J0
Phone	(807) 887-2510
Fax	(807) 887-3446
Website	http://www.redrockband.ca/
Chief	Chief Arlene Wawia
Total Registered Population	1,680
Note	Red Rock has been consulted on an adjacent Transmission Project (Little Jackfish). RES should consider Red Rock as educated on transmission issues and organized for effective consultation. Their main concerns centre on mercury levels in the watershed and impacts on fisheries. Member of the Bamkushwada limited partnership. Significant potential impacts on how to develop a positive relationship given existing expectations and commitments with other parties. Anticipate deep consultation and accommodation process.

Official Name	Pays Plat
Number	191
Address	10 CENTRAL PLACE, PAYS PLAT, ON
Postal code	P0T 3C0
Phone	(807) 824-2541
Fax	(807) 824-2206
Website	http://paysplat.com/
Chief	Chief Xavier Thompson
Total Registered Population	174
Note:	2007-2009 RES provided notice to Pays Plat First Nation regarding another project (Greenwich). Member of the Bamkushwada limited partnership. Significant potential impacts on how to develop a positive relationship given existing expectations and commitments with other parties. Anticipate deep consultation and accommodation process.

Official Name	Ojibways of the Pic River First Nation
Number	192
Address	PO BOX 193, HERON BAY, ON
Postal code	P0T 1R0
Phone	(807) 229-1749
Fax	(807) 229-1944
Website	http://www.picriver.com
Chief	Chief Roy Michano
Total Registered Population	1,106
Note:	Pic River is an experienced Energy Producer with three hydroelectric generating stations. Pic River has dedicated and experienced Consultation and Accommodation staff that will work with proponents. Member of the Bamkushwada limited partnership. Significant potential impacts on how to develop a positive relationship given existing expectations and commitments with other parties. Anticipate deep consultation and accommodation process.

Official Name	Michipicoten
Number	225
Address	PO BOX 1, SITE 8, RR 1, WAWA, ON
Postal code	P0S 1K0
Phone	(705) 856-1993
Fax	(705) 856-1642
Website	http://www.michipicoten.com/
Chief	Chief Joseph Buchell
Total Registered Population	1,006
Note	Michipicoten First Nation has been in land claim negotiations for quite some time. Areas of sensitivity to the community include Dog Lake, the vicinity of Indian Reserves 69/69A on Lake Superior; two parcels of land on each side of Michipicoten Harbour, as well as lands which include the abandoned CN rail bed, an area which closes the gap between a portion of the CN rail bed and what will be reserve lands. Member of the Bamkushwada limited partnership. Significant potential impacts on how to develop a positive relationship given existing expectations and commitments with other parties. Anticipate deep consultation and accommodation process.

Official Name	Pic Mobert
Number	195
Address	PO BOX 717, MOBERT, ON
Postal code	P0M 2J0
Phone	(807) 822-2134
Fax	(807) 822-2850
Website	http://www.picmobert.ca/
Chief	Chief Johanna Desmoulin
Total Registered Population	903
Note	Pic Mobert's Economic Development Strategy identifies power generation as a priority area for the community. Goals are for greater employment opportunities, training and skills apprenticeships for members of the community; and enhanced community infrastructure like upgrades to the Community Hall, Fire Trucks and Fire Hall. Member of the Bamkushwada limited partnership. Significant potential impacts on how to develop a positive relationship given existing expectations and commitments with other parties. Anticipate deep consultation and accommodation process.

Official Name	Missanabie Cree
Number	223
Address	174B, Hwy. 17 EAST, Bell's Point, GARDEN RIVER, ON
Postal code	P6A 6Z1
Phone	(705) 254-2702
Fax	(705) 254-3292
Website	http://www.missanabiecree.com/
Chief	Chief Kim Rainville
Note	Missanabie Cree Development Corporation is mandated to oversee the management and practices of economic development ventures. Priorities of the MCDC include: entrepreneurial opportunities for members of the community; Providing members with employment and training opportunities; Providing other complementary purposes consistent with these objectives. Missanabie Cree have verbal assertions of the exercise of their rights as far as the outskirts of Wawa. Furthermore, Missanabie Cree are in land claim negotiations with Ontario and Canada. The land claim area may intersect with the proposed study area of the project. Further information is required before consultation can be assessed. Presently anticipate light consultation with limited accommodation.

Official Name	Animbiigoo Zaagi’igan Anishinaabek (Lake Nipigon Ojibway)
Number	194
Address	PO BOX 120, BEARDMORE, ON
Postal code	P0T 1G0
Phone	(807) 875-2785
Fax	(807) 875-2786
Website	http://www.aza.ca/
Chief	Chief Yvette Metansinine
Note	The Resource Development Advisor offers a technical advisory service to members and companies/contractors who work within Animbiigoo Zaagi'igan Anishinaabek's Traditional Territory. Further information is required before consultation can be assessed. Presently anticipate moderate consultation with moderate accommodation.

Official Name	Biinjitiwaabik Zaaging Anishinaabek (Rocky Bay)
Number	197
Address	GENERAL DELIVERY, MACDIARMID, ON
Postal code	P0T 2B0
Phone	(807) 885-3401
Fax	(807) 885-1218
Website	http://www.rockybayfn.ca/
Chief	Chief Valda Lesperance
Note	The Rocky Bay Lands and Resource Program is focused on building and supporting consultation capacity as it relates to Lands and Resources at the community level as well as with Government and Industry. The community is experienced with Little Jackfish transmission issues and is actively seeking Wind Energy opportunities. Further information is required before consultation can be assessed. Presently anticipate moderate consultation with moderate accommodation.

Official Name	Bingwi Neyaashi Anishinaabek (Sand Point)
Number	196
Address	146 COURT STREET SOUTH, THUNDER BAY, ON
Postal code	P7B 2X6
Phone	(807) 623-2724
Fax	(807) 623-2764
Website	None
Chief	Chief Emile Gladu
Note	Further information is required before consultation can be assessed. Presently anticipate moderate consultation with moderate accommodation.

Official Name	Ginoogaming First Nation
Number	185
Address	PO BOX 89, LONGLAC, ON
Postal code	P0T 2A0
Phone	(807) 876-2242
Fax	(807) 876-2495
Website	None
Chief	Chief Celia Echum
Note	Further information is required before consultation can be assessed. Presently anticipate moderate consultation with moderate accommodation.

Official Name	Long Lake No. 58 First Nation
Number	184
Address	PO BOX 609, LONGLAC, ON
Postal code	P0T 2A0
Phone	(807) 876-2292
Fax	(807) 876-2757
Website	http://www.longlake58fn.ca/
Chief	Chief Allan Towegishig
Note	Further information is required before consultation can be assessed. Presently anticipate moderate consultation with moderate accommodation.

Official Name	Ojibways of Batchewana
Number	198
Address	236 FRONTENAC STREET, SAULT STE MARIE, ON
Postal code	P6A 5K9
Phone	(705) 759-0914
Fax	(705) 759-9171
Website	
Chief	Chief Dean Sayers
Note	Further information is required before consultation can be assessed. Presently anticipate light consultation with limited accommodation.

Official Name	Ojibways of Garden River
Number	199
Address	7 SHINGWAUK STREET, RR 4, GARDEN RIVER, ON
Postal code	P6A 6Z8
Phone	(705) 946-6300
Fax	(705) 945-1415
Website	
Chief	Chief Lyle Sayers
Note	Further information is required before consultation can be assessed. Presently anticipate light consultation with limited accommodation.

Official Name	Kiashke Zaaging Anishinaabek (Gull Bay)
Number	188
Address	GENERAL DELIVERY, GULL BAY, ON
Postal code	P0T 1P0
Phone	(807) 982-0006
Fax	(807) 982-0009
Website	
Chief	Chief Miles Nowegijick
Note	Further information is required before consultation can be assessed. Presently anticipate moderate consultation with limited accommodation.

Official Name	Métis Nation of Ontario
Address	Attn: Mark Bowler, Director Métis Nation of Ontario 500 Old St. Patrick St, Unit 3 Ottawa, Ontario
Postal code	K1N 9G4
Phone	613-798-1488
Fax	613-722-4225
Website	www.metisnation.org
President	Gary Lipinski
Note	The Metis Nation of Ontario is well organized to meet Consultation obligations. MNO has established a Lands, Resources and Consultations Branch that provides hands-on capacity and support at the community level on lands, resources and consultation issues. The MNO have published detailed consultation and accommodation guidelines for proponents to follow. Anticipate significant relationship building exercises to be undertaken. MNO represents Greenstone Metis Council; Superior North Shore Metis Council; and Thunder Bay Metis Council.

Official Name	Red Sky Métis Independent Nation
Address	406 East Victoria Avenue Thunder Bay, Ontario
Postal code	P7C 1A5
Phone	807-623-4635
Fax	807-623-9331
Website	http://rsmin.ca
Executive Director	Donelda DeLaRonde
Note	Volunteer-run organization with limited resources. Many of the assertions to Aboriginal rights made by Red Sky are yet to be proven. Past consultations regarding mineral exploration proved to be positive experiences. Anticipate Red Sky to be pleased to be invited to provide comment and advice on the project as it develops.

TAB M-3-2

List of Potentially Affected First Nation and Métis Communities

The OPA has identified 14 First Nation communities that might have interest in the EWTL as well as four Métis Nations. The identified First Nations and Métis are:

First Nation communities	
• Animbiigoo Zaagi'igan Anishinaabek First Nation (Lake Nipigon Ojibway)	• Kiashke Zaaging Anishinaabek (Gull Bay) First Nation
• Biinjitiwaabik Zaaging Anishinaabek First Nation (Rocky Bay)	• Ojibways of Batchewana
• Bingwi Neyaashi Anishinaabek (Sand Point First Nation)	• Ojibways of Garden River
• Fort William First Nation	• Ojibways of Pic River (Heron Bay First Nation)
• Ginoogaming First Nation	• Pays Plat First Nation
• Long Lake No.58 First Nation	• Pic Mobert First Nation
• Michipicoten First Nation	• Red Rock Indian Band
• Missanabie Cree First Nation	
Métis communities	
• The Métis Nation of Ontario (MNO) – this includes the following MNO local Councils: the Greenstone Métis Council; the Superior North Shore Métis and the Thunder Bay Métis	• Red Sky Independent Métis Nation (Red Sky)

TAB N-1-1

Project Schedule Overview

Since 2010, the following in-service dates have been projected for the Project: (i) in May 2010, Hydro One projected a 2015 in-service date[1]; (ii) in June 2010, Hydro One projected a November 2016 in-service date, on the assumption that development activities would commence in 2009 and more than three years would be required for construction[2]; (iii) in March 2011, the Ministry of Energy projected a 2016-2017 in-service date[3]; and (iv) in June 2011, the OPA targeted an in-service date of 2017[4]. The OEB's December 2011 announcement of the designation process reflected the OPA's 2017 in-service date.

The Project's in-service date has slipped with each projection, presumably in recognition of the time required to complete development, regulatory and construction activities. In its June 2010 study, Hydro One estimated that more than seven years would be required to complete all of these steps. It is unlikely that designation will occur and development activities begin until well into 2013 and, perhaps, even later. Assuming Hydro One's seven year development and construction schedule, this would result in an in-service date of 2020 or later.

Over the course of this proceeding, the OPA has acknowledged that there is some uncertainty around a 2017 in-service date for the Project. In its May 7, 2012, submission, the OPA stated as follows:

> "The OPA had suggested that transmitters provide input as to whether the 2017 in-service date remains appropriate because nearly a year-and-a-half has passed

---

[1] Hydro One's Transmission Green Energy Plan, May 19, 2010: EB-2010-0002, Exhibit A, Tab 11, Schedule 4.

[2] Hydro One's Project Definition Report, June 4, 2010: AR18379 Project Definition Report, Study Estimates for Options, East-West Tie Expansion.

[3] Ministry of Energy, March 2011: Ontario's Long-Term Energy Plan.

[4] Ontario Power Authority, June 30, 2011: Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion.

> since the project was originally identified in the government's Long-Term Energy Plan, and the OPA thought that it was important to understand the implications of this date from the transmitter's perspective."[5]

The Board's own Filing Requirements contemplate that applicants might propose a different in-service date:

> "The applicant must file as part of its plan…for the construction phase of the project [a] proposed in-service date for the line (<u>can be 2017 or another date</u>)."[6]

<u>Project Schedule</u>

On the basis of its preliminary development activities, the Applicant has concluded that achieving a 2017 in-service date, as stipulated in the OEB's definition of the EWTL[7], is highly unlikely, if not impossible. To achieve a 2017 in-service date would require that the key development tasks be undertaken simultaneously rather than sequentially, thereby imposing significant inefficiency on the development and construction process, as well as creating the potential of problems resulting from rushed and incomplete consultation, route refinement and mitigation processes. Moreover, a 2017 in-service date would require all regulatory and permitting approvals to be obtained on an expedited basis.

In light of the foregoing, the Applicant proposes a development and construction schedule designed to achieve a year-end 2018 in-service date. This milestone is conditional upon the receipt of timely regulatory (i.e., LTC) and permitting approvals.

Figure N-1, below, sets out the principal project development and construction milestones.

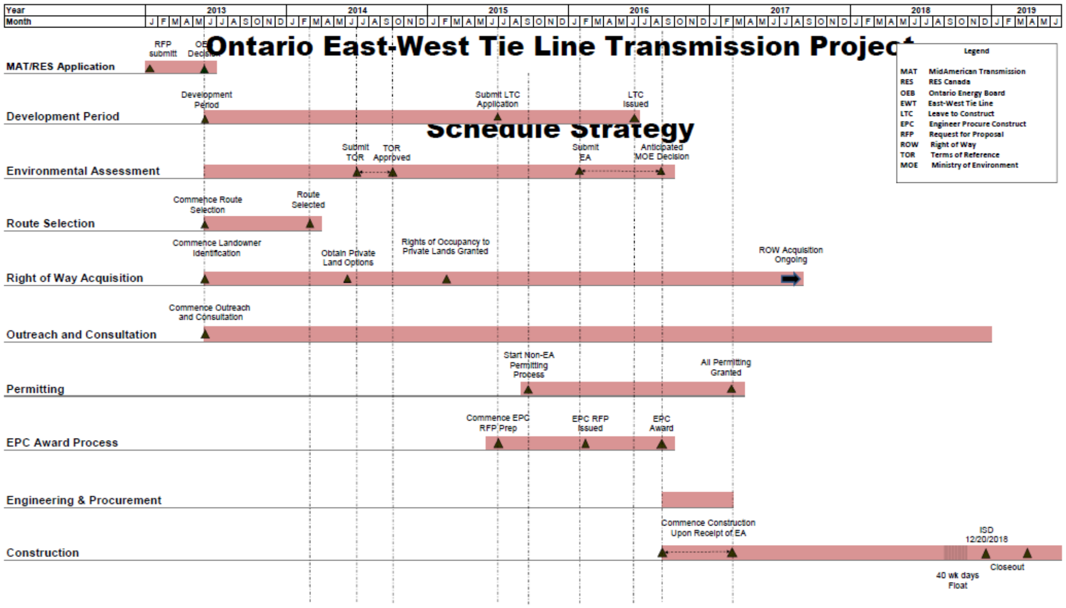
---

[5] Ontario Power Authority, May 7, 2012: EB-2011-0140, Proceedings to Designate a Transmitter to Carry Out Development Work for the East-West Tie Line – Phase 1

[6] OED, July 12, 2012: EB-2011-0140, Phase 1 Decision and Order, Appendix A, Filing Requirements, S. 7.3 East-West Tie Designation Applications [emphasis added].

[7] OEB letter to All Electricity Transmitters Registered for the East-West Tie Line (December 20, 2011), Attachment 1, p. 2.

Figure N-1: Project Schedule



The Project schedule set out above assumes that the designation process will be completed by mid-2013 and that the LTC process commences in mid-2015 and is completed by mid-2016. It also assumes that permit approvals are secured shortly after the conclusion of the LTC process. The Project schedule further assumes that the OPA, in concert with the designated transmitter, would complete the required Project cost-benefit study by mid-2015. Finally, the Project schedule assumes that development activities, including the commencement of the competitive bidding process to select an EPC contractor, would continue throughout the LTC process.

In order to achieve a year-end 2018 in-service date, the Applicant proposes an aggressive but realistic five and one-half year development and construction process commencing mid-2013. The process comprises the following three phases:

(i) a two-year Development Phase;

(ii) a one-year LTC phase; and

(iii) a two-and-one-half-year Construction Phase.

Activities during these three phases will overlap to some extent, in order to achieve the 2018 in-service date. For instance, many pre-construction activities will occur in the LTC phase (during the LTC process) and up to the commencement of the Construction Phase, in late 2016 or early 2017. The Applicant will, to the extent possible, attempt to bring sections of the Project into service, ahead of 2018.

The Development Phase Schedule

The Applicant's development schedule is aggressive, but realistic assuming timely (but not expedited) receipt of regulatory and permitting approvals. It comprises the following components:

(i) **Route Evaluation and Selection**: The Project schedule assumes nine months to evaluate and select a route based on the Preliminary Preferred Route.

(ii) **Environmental Terms of Reference ("ToR")**: This process will occur at the same time as the route evaluation and selection process; assuming three months is required to secure MOE approvals, the ToR process should conclude at the end of 2014.

(iii) **Environmental Assessment ("EA")**: EA activities will overlap with the latter part of the ToR process and an EA will be submitted to the MOE, in early 2016, mid-way through the LTC process. Assuming that nine months are required for MOE approval, the EA will be completed roughly three months after the completion of the LTC process.

(iv) **Land Control**: Applicant will negotiate option agreements before the LTC application is submitted in mid-2015. The options will be exercised immediately after an LTC order is issued. With respect to Crown lands, the Applicant will file the formal request for the MNR Land Use Permit that is required for construction, immediately after the issuance of the LTC order. Crown land easements will be finalized with MNR after construction based on "as built surveys".

(v) **Outreach, Consultation and First Nation and Métis Participation**: As soon as it is designated, the Applicant will begin communicating with and reaching out to landowners, local communities, First Nation and Métis communities, governmental entities and other stakeholders. It will continue these efforts throughout the Project's Development and Construction Phases. These efforts will be integral to finalizing a route and mitigating impacts. First Nation and Métis participation agreements will be negotiated during the Development Phase but will not be effective until an LTC order is issued.

(vi) **Permitting**: Permitting activities will commence during the LTC process and will end in early 2017, at the commencement of the Construction Phase.

(vii) **EPC Selection and Contracting**: Conducting a competitive bidding process for selecting an EPC contractor will require considerable effort and cost. Accordingly, the process will commence when the LTC application is filed and will end shortly after the LTC process ends.

The Construction Phase Schedule

The Construction Phase will commence after the receipt of an LTC order, an EA approval and the award of EPC and related contracts. The Construction Phase comprises the following activities: construction of transmission lines, structures and foundations; construction of access roads; installation of grounding facilities; testing and commissioning; environmental management and vegetation management activities; localized permitting; and permit compliance efforts.

During the Construction Phase, the transmission line will be constructed up to and including the dead-end transmission line structures within 250 metres of Wawa TS, Marathon TS and Lakehead TS.[8] The Applicant will coordinate with Hydro One who will be responsible for installing the physical interconnections into the stations. This substation connection work will need to be completed on or before November 2, 2018, in order to allow for testing of the transmission line. Final testing of the transmission line is scheduled to occur between November 2, 2018 and December 19, 2018, subject to Hydro One and IESO approval.

Meeting Milestones

The Applicant and its development team approach the Project understanding the importance of meeting all milestones to achieve the in-service date. However, the Applicant also recognizes that construction projects are fraught with risk, unknowns and unexpected decisions that can affect the Project's milestones.

The Applicant will first identify aspects within the Project team's control and aspects subject to outside control. Next, the Applicant will plan effectively to reduce all opportunities for failure and accurately monitor progress (using earned value methods where appropriate) to identify trends and problems that would mitigate impact. Finally, the Applicant will develop alternative "what-if" scenarios should a milestone date not be met.

In the event of a missed milestone date, the Applicant would either implement a contingency plan or evaluate options to revise the approach in order to keep the Project's other milestones on schedule. The Applicant will include, in its contracts with consultants and contractors, terms that require the parties to identify when critical path schedules fall behind pre-determined variance points and implement recovery plans; a

---

[8] This is a criterion of the Board's minimum technical requirements in attachment 1 of the Board's letter to Registered Electricity Transmitters, dated December 20, 2011.

term would also give the Applicant the right to terminate contracts for cause and retain replacement services, where appropriate.

Under its Development and Construction Cost Proposal (described in Exhibit B-1-1), the Applicant would bear much of the financial consequences of failing to meet milestones regardless of whether the failure was related to reasons within or outside the control of the Applicant. The only exception to this is in the case of the pass-through of the difference between the actual costs incurred in the following four categories and the estimates of such costs that are embedded in the Bid Amounts as follows: land acquisition (up to $15.5 million); First Nation and Métis participation costs and accommodation (up to $1.0 million); environmental and permitting costs (up to $2.5 million); and line costs in respect of a total line length that exceeds 410 km ($1 million for each additional km).

TAB N-1-2

Project Execution Chart

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

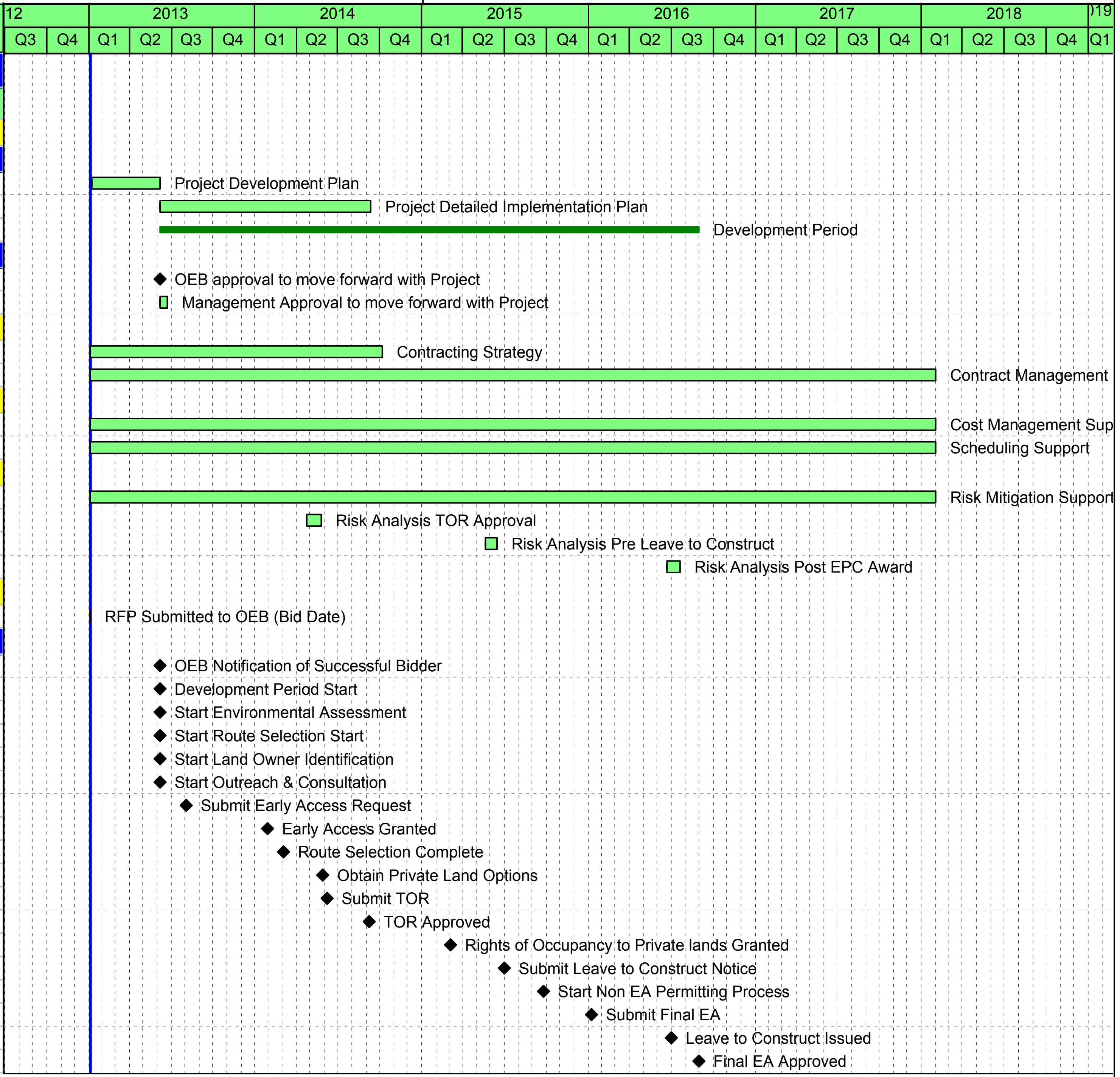
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
E-W Tie - 12-05-12 OEB Post Bid		1528d	04-Jan-13	21-Feb-19
Project Management		1527d	04-Jan-13	20-Feb-19
Project Management		910d	07-Jan-13	31-Aug-16
Project Planning		910d	07-Jan-13	31-Aug-16
A1000	Project Development Plan	104d	07-Jan-13	06-Jun-13
A1010	Project Detailed Implementation Plan	314d	06-Jun-13	10-Sep-14
A2360	Development Period	806d	06-Jun-13	31-Aug-16
Project Approvals		11d	06-Jun-13	21-Jun-13
A1030	OEB approval to move forward with Project	0d	06-Jun-13	
A1020	Management Approval to move forward with Project	10d	07-Jun-13	21-Jun-13
Contract Management		1264d	04-Jan-13	01-Feb-18
A1080	Contracting Strategy	438d	04-Jan-13	07-Oct-14
A1090	Contract Management Support	1264d	04-Jan-13	01-Feb-18
Project Controls		1264d	04-Jan-13	01-Feb-18
A1060	Cost Management Support	1264d	04-Jan-13	01-Feb-18
A1070	Scheduling Support	1264d	04-Jan-13	01-Feb-18
Risk Management		1264d	04-Jan-13	01-Feb-18
A1110	Risk Mitigation Support	1264d	04-Jan-13	01-Feb-18
A1100	Risk Analysis TOR Approval	20d	25-Apr-14	26-May-14
A2560	Risk Analysis Pre Leave to Construct	20d	19-May-15	16-Jun-15
A63000	Risk Analysis Post EPC Award	20d	20-Jun-16	19-Jul-16
Project Milestones		1527d	04-Jan-13	20-Feb-19
A2300	RFP Submitted to OEB (Bid Date)	1d	04-Jan-13	04-Jan-13*
Project Milestones (Development)		926d	06-Jun-13	24-Feb-17
A2310	OEB Notification of Successful Bidder	0d		06-Jun-13
A64180	Development Period Start	0d	06-Jun-13	
A2370	Start Environmental Assessment	0d	07-Jun-13	
A2380	Start Route Selection Start	0d	07-Jun-13	
A2420	Start Land Owner Identification	0d	07-Jun-13	
A2450	Start Outreach & Consultation	0d	07-Jun-13	
A64160	Submit Early Access Request	0d	02-Aug-13	
A64170	Early Access Granted	0d		28-Jan-14
A2410	Route Selection Complete	0d		04-Mar-14
A2431	Obtain Private Land Options	0d		30-May-14
A2340	Submit TOR	0d	09-Jun-14	
A2350	TOR Approved	0d	09-Sep-14	
A2441	Rights of Occupancy to Private lands Granted	0d		05-Mar-15
A2320	Submit Leave to Construct Notice	0d	30-Jun-15	
A2460	Start Non EA Permitting Process	0d	24-Sep-15	
A2390	Submit Final EA	0d	07-Jan-16	
A2330	Leave to Construct Issued	0d		30-Jun-16
A2400	Final EA Approved	0d		31-Aug-16



🟩 Remaining Level of Effort ▬ % Complete

🟦 Actual Level of Effort

🟦 Actual Work

🟩 Remaining Work

🟥 Critical Remaining Work

◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

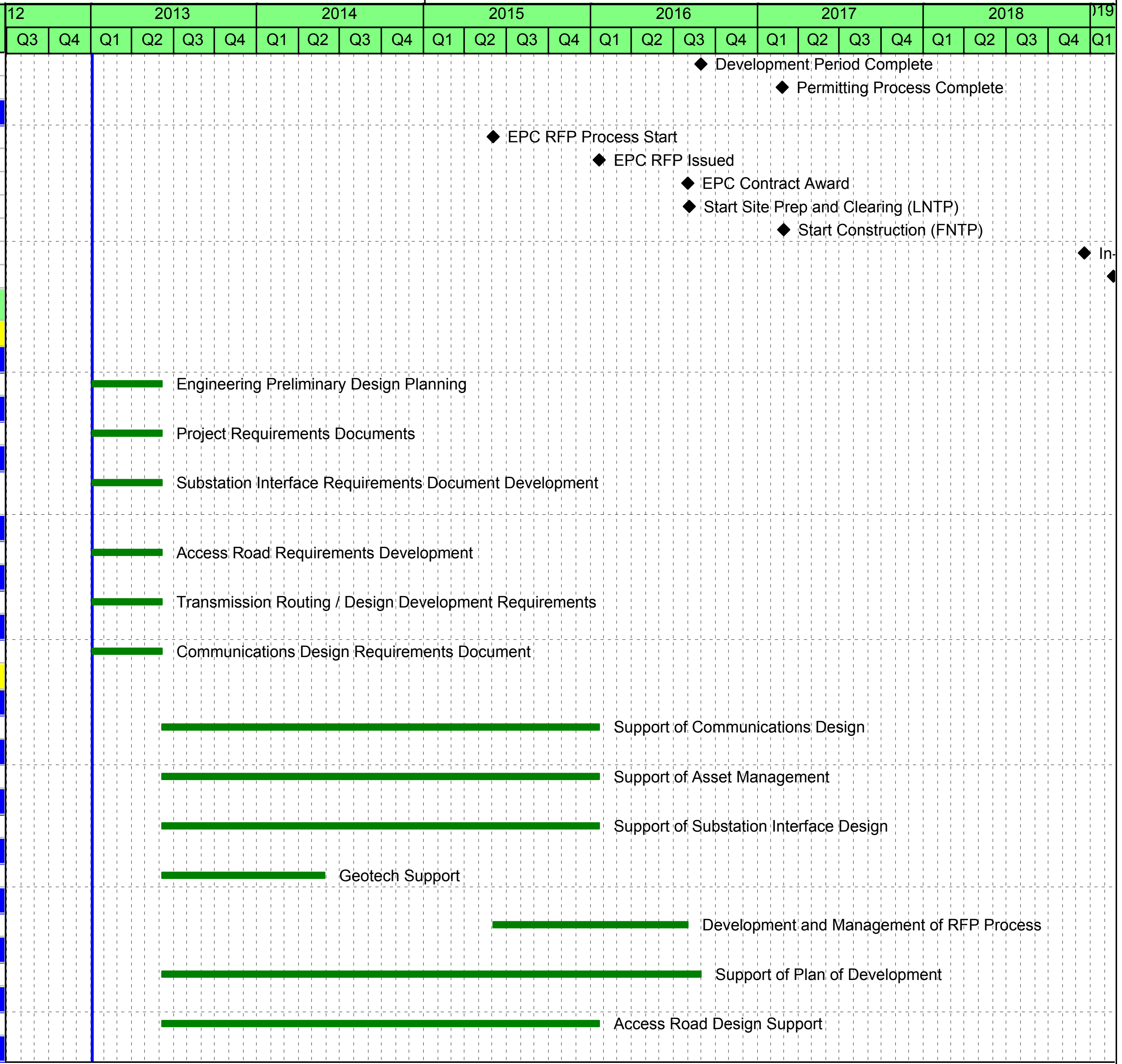
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
A64190	Development Period Complete	0d		31-Aug-16
A2470	Permitting Process Complete	0d		24-Feb-17
Project Milestones (Construction)		928d	01-Jun-15	20-Feb-19
A2480	EPC RFP Process Start	0d	01-Jun-15	
A2490	EPC RFP Issued	0d	21-Jan-16	
A2500	EPC Contract Award	0d		03-Aug-16
A2510	Start Site Prep and Clearing (LNTP)	0d	04-Aug-16	
A2520	Start Construction (FNTP)	0d	27-Feb-17	
A2530	In-Service Date	0d		19-Dec-18
A2540	Project Completion	0d		20-Feb-19
Engineering		1527d	04-Jan-13	20-Feb-19
Preliminary Design & Engineering PMO		106d	04-Jan-13	06-Jun-13
Project Development Planning		106d	04-Jan-13	06-Jun-13
A1120	Engineering Preliminary Design Planning	106d	04-Jan-13	06-Jun-13
Project Requirements Document		106d	04-Jan-13	06-Jun-13
A1130	Project Requirements Documents	106d	04-Jan-13	06-Jun-13
Substation Interface Pre-Engineering		106d	04-Jan-13	06-Jun-13
A1190	Substation Interface Requirements Document Development	106d	04-Jan-13	06-Jun-13
Access Roads Pre-Engineering		106d	04-Jan-13	06-Jun-13
A1180	Access Road Requirements Development	106d	04-Jan-13	06-Jun-13
Transmission Pre-Engineering		106d	04-Jan-13	06-Jun-13
A1170	Transmission Routing / Design Development Require...	106d	04-Jan-13	06-Jun-13
Communications Pre-Engineering		106d	04-Jan-13	06-Jun-13
A1150	Communications Design Requirements Document	106d	04-Jan-13	06-Jun-13
Design & Engineering PMO		1421d	06-Jun-13	20-Feb-19
Communications Design Support		653d	06-Jun-13	21-Jan-16
A1250	Support of Communications Design	653d	06-Jun-13	21-Jan-16
Asset Management Support		653d	06-Jun-13	21-Jan-16
A1380	Support of Asset Management	653d	06-Jun-13	21-Jan-16
Substation Engineering Support		653d	06-Jun-13	21-Jan-16
A1390	Support of Substation Interface Design	653d	06-Jun-13	21-Jan-16
Geotech Support		244d	06-Jun-13	30-May-14
A1400	Geotech Support	244d	06-Jun-13	30-May-14
RFP Development Support		293d	01-Jun-15	03-Aug-16
A1410	Development and Management of RFP Process	293d	01-Jun-15	03-Aug-16
Plan of Development Support (POD)		806d	06-Jun-13	31-Aug-16
A1420	Support of Plan of Development	806d	06-Jun-13	31-Aug-16
Access Roads Design Support		653d	06-Jun-13	21-Jan-16
A1430	Access Road Design Support	653d	06-Jun-13	21-Jan-16
Transmission Engineering Design Support		653d	06-Jun-13	21-Jan-16



- 🟩 Remaining Level of Effort ▬ % Complete
- ▬ Actual Level of Effort
- 🟦 Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

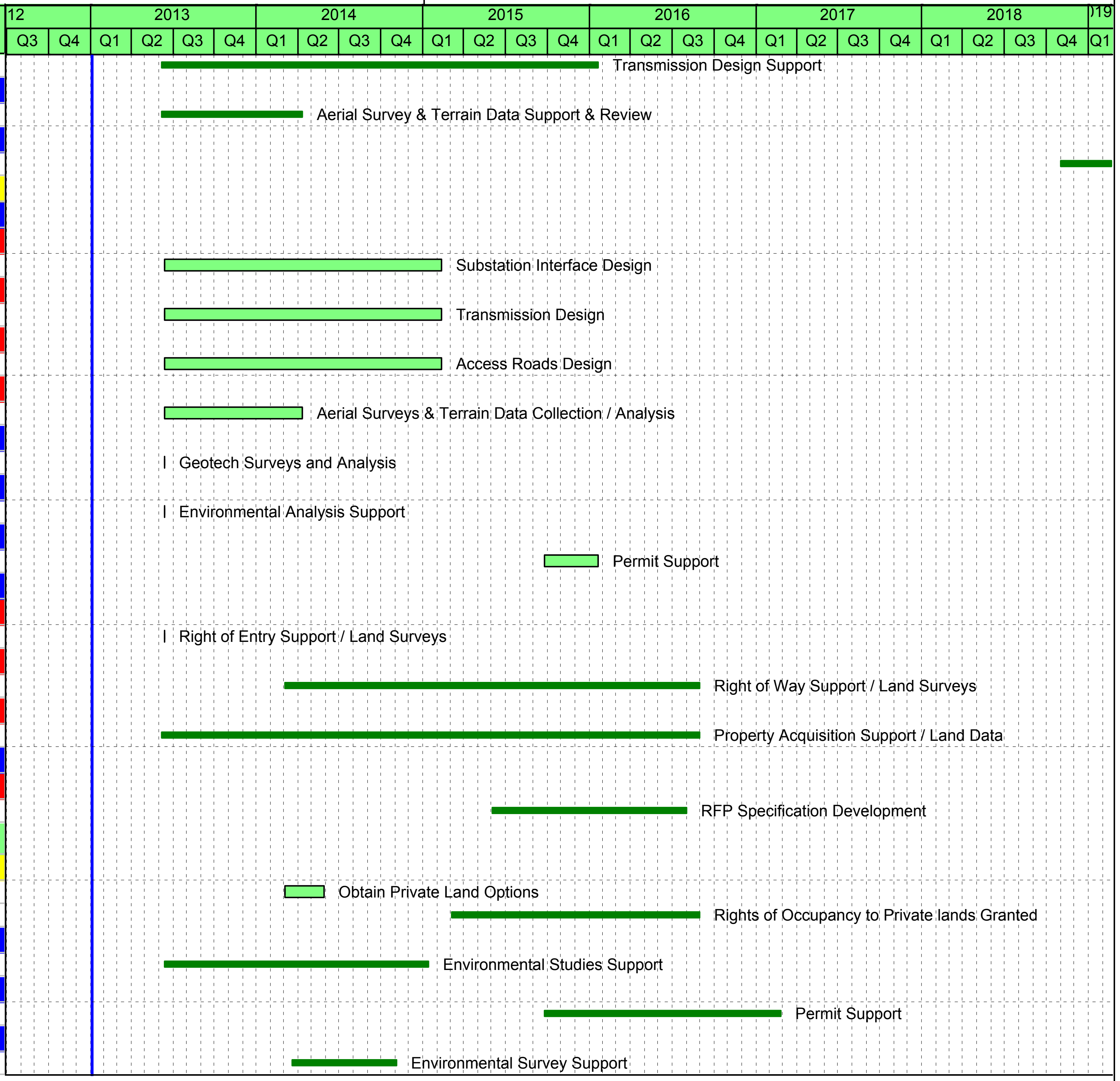
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
A1440	Transmission Design Support	653d	06-Jun-13	21-Jan-16
Preliminary Aerial Surveys & Terrain Data		209d	06-Jun-13	10-Apr-14
A1140	Aerial Survey & Terrain Data Support & Review	209d	06-Jun-13	10-Apr-14
Close Out Support		75d	02-Nov-18	20-Feb-19
A1450	Project Close Out Support	75d	02-Nov-18	20-Feb-19
OE Engineering-Development		805d	07-Jun-13	31-Aug-16
Preliminary Design & Engineering		415d	13-Jun-13	12-Feb-15
Substation Interface		415d	13-Jun-13	12-Feb-15
A1210	Substation Interface Design	415d	13-Jun-13	12-Feb-15
Transmission Line		415d	13-Jun-13	12-Feb-15
A1220	Transmission Design	415d	13-Jun-13	12-Feb-15
Access Roads		415d	13-Jun-13	12-Feb-15
A1230	Access Roads Design	415d	13-Jun-13	12-Feb-15
Aerial Surveys & Terrain Data		204d	13-Jun-13	10-Apr-14
A1240	Aerial Surveys & Terrain Data Collection / Analysis	204d	13-Jun-13	10-Apr-14
Geotechnical Surveys		1d	13-Jun-13	14-Jun-13
A1260	Geotech Surveys and Analysis	1d	13-Jun-13	14-Jun-13
Environmental Support		1d	13-Jun-13	14-Jun-13
A1280	Environmental Analysis Support	1d	13-Jun-13	14-Jun-13
Permit Support		80d	24-Sep-15	21-Jan-16
A1270	Permit Support	80d	24-Sep-15	21-Jan-16
Property Support		805d	07-Jun-13	31-Aug-16
Right of Entry Support		1d	13-Jun-13	14-Jun-13
A1310	Right of Entry Support / Land Surveys	1d	13-Jun-13	14-Jun-13
Right of Way Support		622d	05-Mar-14	31-Aug-16
A1300	Right of Way Support / Land Surveys	622d	05-Mar-14	31-Aug-16
Property Acquisition Support		805d	07-Jun-13	31-Aug-16
A1290	Property Acquisition Support / Land Data	805d	07-Jun-13	31-Aug-16
RFP Support		293d	01-Jun-15	03-Aug-16
Transmission RFP Development		293d	01-Jun-15	03-Aug-16
A2550	RFP Specification Development	293d	01-Jun-15	03-Aug-16
Environmental		925d	07-Jun-13	24-Feb-17
Environmental PMO		925d	07-Jun-13	24-Feb-17
A2430	Obtain Private Land Options	60d	05-Mar-14	30-May-14
A2440	Rights of Occupancy to Private lands Granted	372d	06-Mar-15	31-Aug-16
Environmental Study Support		393d	13-Jun-13	12-Jan-15
A1370	Environmental Studies Support	393d	13-Jun-13	12-Jan-15
Permit Support		354d	24-Sep-15	24-Feb-17
A1360	Permit Support	354d	24-Sep-15	24-Feb-17
Environmental Survey Support		157d	19-Mar-14	03-Nov-14
A1350	Environmental Survey Support	157d	19-Mar-14	03-Nov-14



🟩	Remaining Level of Effort
▬	% Complete
🟦	Actual Level of Effort
🟦	Actual Work
🟩	Remaining Work
🟥	Critical Remaining Work
◆ ◆	Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

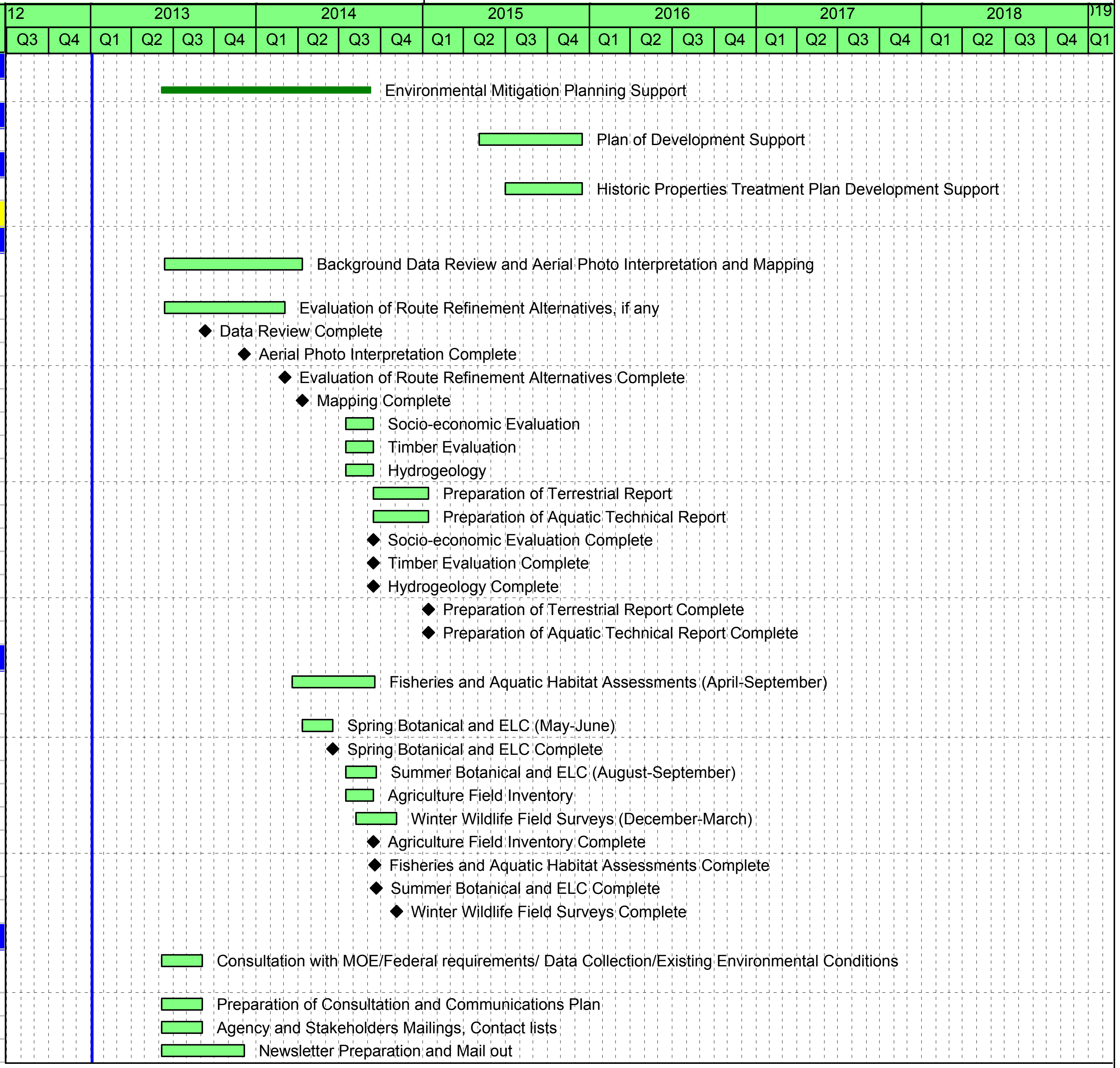
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
Environmental Mitigation Plan Support		312d	07-Jun-13	09-Sep-14
A1340	Environmental Mitigation Planning Support	312d	07-Jun-13	09-Sep-14
POD Support		157d	04-May-15	17-Dec-15
A1330	Plan of Development Support	157d	04-May-15	17-Dec-15
Historic Properties Treatment Plan		117d	30-Jun-15	17-Dec-15
A1320	Historic Properties Treatment Plan Development Sup...	117d	30-Jun-15	17-Dec-15
Environmental Consultant		925d	07-Jun-13	24-Feb-17
Environmental Studies		393d	13-Jun-13	12-Jan-15
T2.01	Background Data Review and Aerial Photo Interpretation and Mapping	205d	13-Jun-13	10-Apr-14
T2.02	Evaluation of Route Refinement Alternatives, if any	180d	13-Jun-13	04-Mar-14
T2.01a	Data Review Complete	0d		09-Sep-13
T2.01b	Aerial Photo Interpretation Complete	0d		04-Dec-13
T2.02a	Evaluation of Route Refinement Alternatives Complete	0d		04-Mar-14
T2.01c	Mapping Complete	0d		10-Apr-14
T2.09	Socio-economic Evaluation	40d	17-Jul-14	15-Sep-14
T2.10	Timber Evaluation	40d	17-Jul-14	15-Sep-14
T2.11	Hydrogeology	40d	17-Jul-14	15-Sep-14
T2.12	Preparation of Terrestrial Report	80d	15-Sep-14	12-Jan-15
T2.13	Preparation of Aquatic Technical Report	80d	15-Sep-14	12-Jan-15
T2.09a	Socio-economic Evaluation Complete	0d		15-Sep-14
T2.10a	Timber Evaluation Complete	0d		15-Sep-14
T2.11a	Hydrogeology Complete	0d		15-Sep-14
T2.12a	Preparation of Terrestrial Report Complete	0d		12-Jan-15
T2.13a	Preparation of Aquatic Technical Report Complete	0d		12-Jan-15
Environmental Surveys		157d	19-Mar-14	03-Nov-14
T2.06	Fisheries and Aquatic Habitat Assessments (April-September)	125d	19-Mar-14	17-Sep-14
T2.04	Spring Botanical and ELC (May-June)	48d	11-Apr-14	18-Jun-14
T2.04a	Spring Botanical and ELC Complete	0d		18-Jun-14
T2.05	Summer Botanical and ELC (August-September)	44d	17-Jul-14	19-Sep-14
T2.08	Agriculture Field Inventory	40d	17-Jul-14	15-Sep-14
T2.03	Winter Wildlife Field Surveys (December-March)	62d	06-Aug-14	03-Nov-14
T2.08a	Agriculture Field Inventory Complete	0d		15-Sep-14
T2.06a	Fisheries and Aquatic Habitat Assessments Complete	0d		17-Sep-14
T2.05a	Summer Botanical and ELC Complete	0d		19-Sep-14
T2.03a	Winter Wildlife Field Surveys Complete	0d		03-Nov-14
Environmental Impact Statement		802d	07-Jun-13	26-Aug-16
T1.01	Consultation with MOE/Federal requirements/ Data Collection/Existing Environmental Conditions	60d	07-Jun-13	04-Sep-13
T1.02	Preparation of Consultation and Communications Plan	60d	07-Jun-13*	04-Sep-13
T1.03	Agency and Stakeholders Mailings, Contact lists	60d	07-Jun-13*	04-Sep-13
T1.04	Newsletter Preparation and Mail out	124d	07-Jun-13*	05-Dec-13



🟩	Remaining Level of Effort
▬	% Complete
▬	Actual Level of Effort
🟦	Actual Work
🟩	Remaining Work
🟥	Critical Remaining Work
◆ ◆	Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

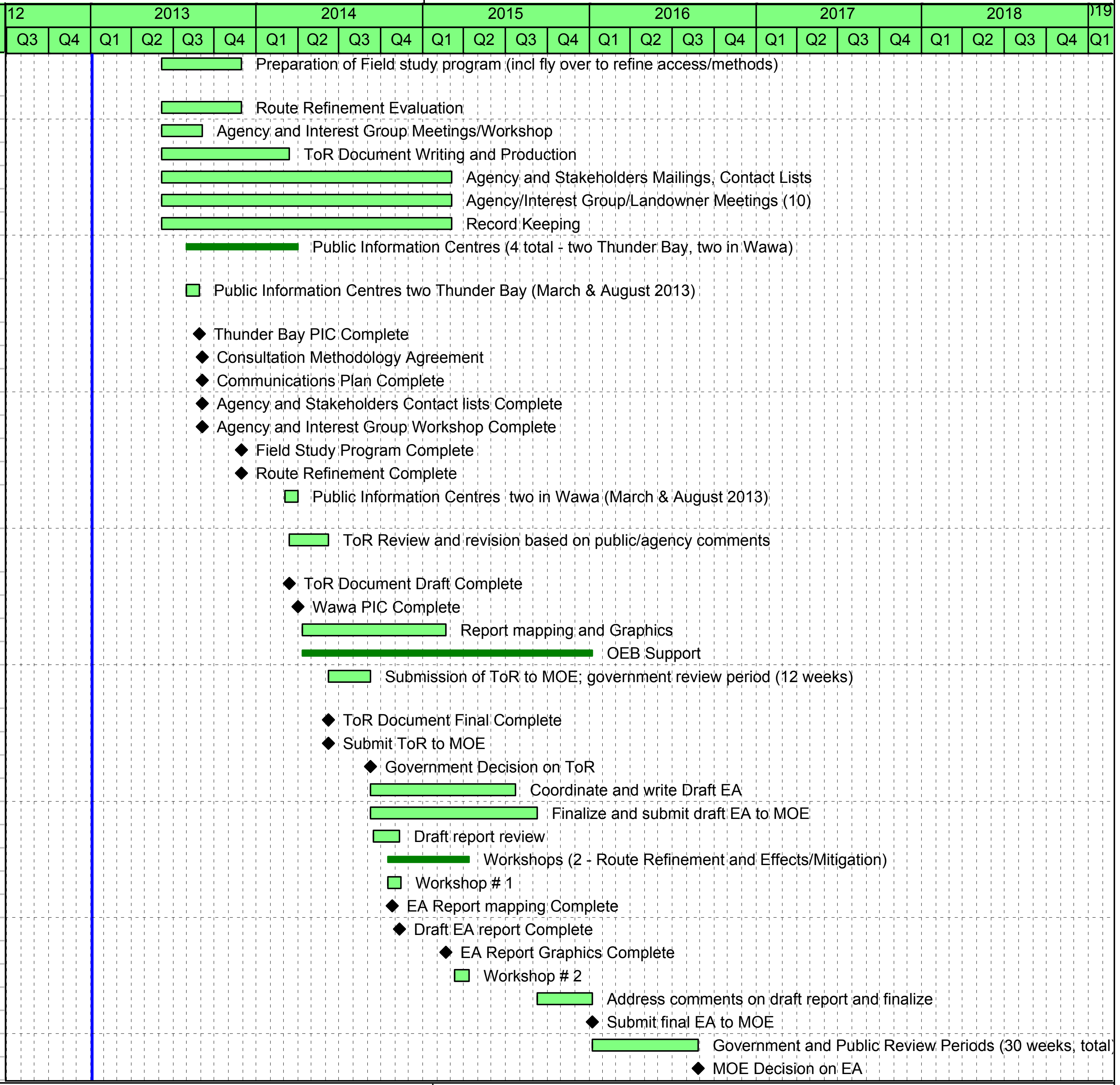
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
T1.06	Preparation of Field study program (incl fly over to refine access/methods)	120d	07-Jun-13	29-Nov-13
T1.07	Route Refinement Evaluation	120d	07-Jun-13	29-Nov-13
T1.08	Agency and Interest Group Meetings/Workshop	60d	07-Jun-13	04-Sep-13
T1.09	ToR Document Writing and Production	189d	07-Jun-13	12-Mar-14
T3.01	Agency and Stakeholders Mailings, Contact Lists	433d	07-Jun-13	05-Mar-15
T3.04	Agency/Interest Group/Landowner Meetings (10)	432d	07-Jun-13	04-Mar-15
T3.05	Record Keeping	432d	07-Jun-13	04-Mar-15
T1.05	Public Information Centres (4 total - two Thunder Bay, two in Wawa)	164d	01-Aug-13	31-Mar-14
T1.05a	Public Information Centres two Thunder Bay (March & August 2013)	20d	01-Aug-13*	29-Aug-13
T1.05a1	Thunder Bay PIC Complete	0d		29-Aug-13
T1.01a	Consultation Methodology Agreement	0d		04-Sep-13
T1.02a	Communications Plan Complete	0d		04-Sep-13
T1.03a	Agency and Stakeholders Contact lists Complete	0d		04-Sep-13
T1.08a	Agency and Interest Group Workshop Complete	0d		04-Sep-13
T1.06a	Field Study Program Complete	0d		29-Nov-13
T1.07a	Route Refinement Complete	0d		29-Nov-13
T1.05b	Public Information Centres two in Wawa (March & August 2013)	20d	03-Mar-14*	31-Mar-14
T1.10	ToR Review and revision based on public/agency comments	60d	12-Mar-14	09-Jun-14
T1.09a	ToR Document Draft Complete	0d		12-Mar-14
T1.05b1	Wawa PIC Complete	0d		31-Mar-14
T2.15	Report mapping and Graphics	216d	11-Apr-14	20-Feb-15
T4.01	OEB Support	434d	11-Apr-14	07-Jan-16
T1.11	Submission of ToR to MOE; government review period (12 weeks)	63d	09-Jun-14	09-Sep-14
T1.10b	ToR Document Final Complete	0d		09-Jun-14
T1.11a	Submit ToR to MOE	0d		09-Jun-14
T1.12	Government Decision on ToR	0d	09-Sep-14	
T2.14	Coordinate and write Draft EA	216d	09-Sep-14	22-Jul-15
T2.17	Finalize and submit draft EA to MOE	250d	09-Sep-14	10-Sep-15
T2.16	Draft report review	40d	15-Sep-14	12-Nov-14
T3.07	Workshops (2 - Route Refinement and Effects/Mitigati...	120d	17-Oct-14	13-Apr-15
T3.07a	Workshop # 1	20d	17-Oct-14	14-Nov-14
T2.15a	EA Report mapping Complete	0d		27-Oct-14
T2.16a	Draft EA report Complete	0d		12-Nov-14
T2.15b	EA Report Graphics Complete	0d		20-Feb-15
T3.07b	Workshop # 2	20d	13-Mar-15	13-Apr-15
T2.18	Address comments on draft report and finalize	80d	10-Sep-15	07-Jan-16
T2.19	Submit final EA to MOE	0d		07-Jan-16
T2.20	Government and Public Review Periods (30 weeks, to...	160d	07-Jan-16	26-Aug-16
T2.21	MOE Decision on EA	0d		26-Aug-16



- 🟩 Remaining Level of Effort
- ▬ % Complete
- 🟦 Actual Level of Effort
- 🟦 Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ ◆ Milestone

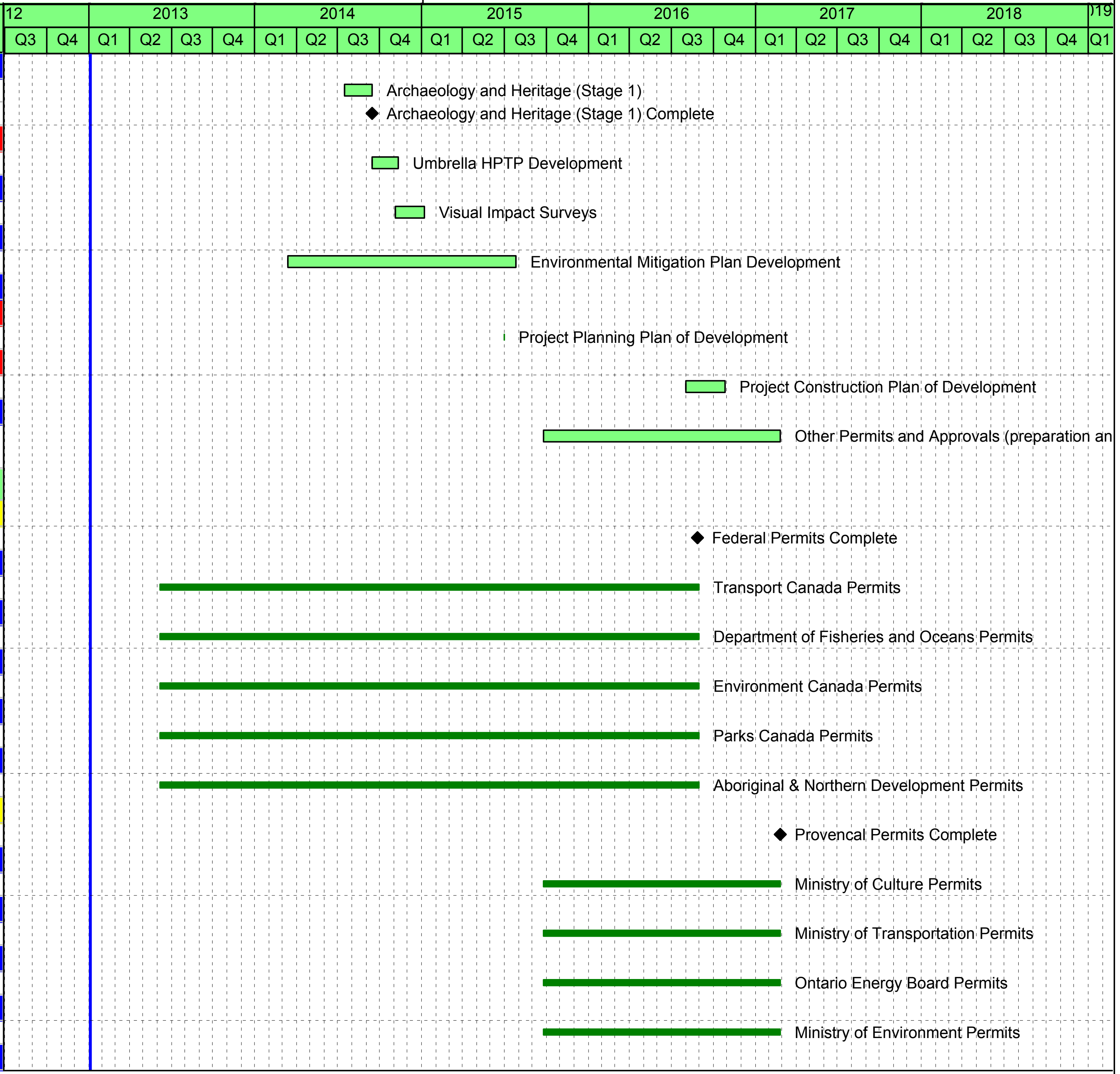
Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

Activity ID	Activity Name	Original Duration	Start	Finish
Historic Properties Treatment Plan		80d	17-Jul-14	12-Nov-14
T2.07	Archaeology and Heritage (Stage 1)	40d	17-Jul-14	15-Sep-14
T2.07a	Archaeology and Heritage (Stage 1) Complete	0d		15-Sep-14
Umbrella HPTP Support		40d	15-Sep-14	12-Nov-14
A1500	Umbrella HPTP Development	40d	15-Sep-14	12-Nov-14
Environmental Visual Impact Surveys		40d	05-Nov-14	06-Jan-15
A1510	Visual Impact Surveys	40d	05-Nov-14	06-Jan-15
Environmental Mitigation Plan		342d	12-Mar-14	27-Jul-15
A1520	Environmental Mitigation Plan Development	342d	12-Mar-14	27-Jul-15
Plan of Development (POD)		332d	30-Jun-15	28-Oct-16
Planning POD		0d	30-Jun-15	30-Jun-15
A1540	Project Planning Plan of Development	0d	30-Jun-15	30-Jun-15
Construction POD		60d	03-Aug-16	28-Oct-16
A1530	Project Construction Plan of Development	60d	03-Aug-16	28-Oct-16
Permit Support		354d	24-Sep-15	24-Feb-17
T5.01	Other Permits and Approvals (preparation and submission of applications)	354d	24-Sep-15	24-Feb-17
Permits		926d	06-Jun-13	24-Feb-17
Federal		806d	06-Jun-13	31-Aug-16
A63020	Federal Permits Complete	0d		26-Aug-16
Transport Canada (TC)		806d	06-Jun-13	31-Aug-16
A1560	Transport Canada Permits	806d	06-Jun-13	31-Aug-16
Department of Fisheries and Oceans (DFO)		806d	06-Jun-13	31-Aug-16
A1570	Department of Fisheries and Oceans Permits	806d	06-Jun-13	31-Aug-16
Environment Canada (EC)		806d	06-Jun-13	31-Aug-16
A1580	Environment Canada Permits	806d	06-Jun-13	31-Aug-16
Parks Canada (PC)		806d	06-Jun-13	31-Aug-16
A1590	Parks Canada Permits	806d	06-Jun-13	31-Aug-16
Aboriginal and Northern Development (AANDC		806d	06-Jun-13	31-Aug-16
A1600	Aboriginal & Northern Development Permits	806d	06-Jun-13	31-Aug-16
Provencal		354d	24-Sep-15	24-Feb-17
A63010	Provencal Permits Complete	0d		24-Feb-17
Ministry of Culture		354d	24-Sep-15	24-Feb-17
A1610	Ministry of Culture Permits	354d	24-Sep-15	24-Feb-17
Ministry of Transportation		354d	24-Sep-15	24-Feb-17
A1670	Ministry of Transportation Permits	354d	24-Sep-15	24-Feb-17
Ontario Energy Board		354d	24-Sep-15	24-Feb-17
A1660	Ontario Energy Board Permits	354d	24-Sep-15	24-Feb-17
Ministry of Environment		354d	24-Sep-15	24-Feb-17
A1650	Ministry of Environment Permits	354d	24-Sep-15	24-Feb-17
Lakehead Region Conservation Authority (LRCA)		354d	24-Sep-15	24-Feb-17



▬ Remaining Level of Effort ▬ % Complete
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
A1640	Lakehead Region Conservation Authority Permits	354d	24-Sep-15	24-Feb-17
Ministry of Natural Resources (MNR)		354d	24-Sep-15	24-Feb-17
A1630	Ministry of natural Resources Permits	354d	24-Sep-15	24-Feb-17
Natural Resources Canada		354d	24-Sep-15	24-Feb-17
A1620	Natural Resources Canada Permits	354d	24-Sep-15	24-Feb-17
Municipal		354d	24-Sep-15	24-Feb-17
A63030	Municipal Permits Complete	0d		24-Feb-17
Local Municipalities		354d	24-Sep-15	24-Feb-17
A1700	Local Municipalities Permits	354d	24-Sep-15	24-Feb-17
Local Townships		354d	24-Sep-15	24-Feb-17
A1690	Local Townships Permits	354d	24-Sep-15	24-Feb-17
Ministry of Environment		354d	24-Sep-15	24-Feb-17
A1680	Ministry of Environment Permits	354d	24-Sep-15	24-Feb-17
Other		354d	24-Sep-15	24-Feb-17
A63040	Other Permits Complete	0d		24-Feb-17
Pipelines (Oil and Gas)		354d	24-Sep-15	24-Feb-17
A1780	Pipelines (O&G) Permits	354d	24-Sep-15	24-Feb-17
Fiber Optic		354d	24-Sep-15	24-Feb-17
A1770	Fiber Optic Permit Permits	354d	24-Sep-15	24-Feb-17
CN Railroad		354d	24-Sep-15	24-Feb-17
A1760	CN Rail Permits	354d	24-Sep-15	24-Feb-17
CP Railroad		354d	24-Sep-15	24-Feb-17
A1750	CP Rail Permits	354d	24-Sep-15	24-Feb-17
Ministry of Northern Development and Mines (MNDM)		354d	24-Sep-15	24-Feb-17
A1740	MNDM Permits	354d	24-Sep-15	24-Feb-17
IESO		354d	24-Sep-15	24-Feb-17
A1730	IESO Coordination / Support	354d	24-Sep-15	24-Feb-17
OGCC		354d	24-Sep-15	24-Feb-17
A1720	OGCC Coordination / Support	354d	24-Sep-15	24-Feb-17
Community Relations		1378d	06-Jun-13	19-Dec-18
First Nations and Metis		432d	07-Jun-13	04-Mar-15
T3.06	First nation and Metis Meetings (8)	432d	07-Jun-13	04-Mar-15
Provincial Permit Support		427d	04-Sep-13	25-May-15
T3.02	Newsletter Preparation and Mail out (4)	373d	04-Sep-13	05-Mar-15
A1790	Provincial Permit Coordination / Support	427d	04-Sep-13	25-May-15
T3.03	Public Information Centres (3 rounds in 4 locations = 12 total)	175d	09-Sep-14	25-May-15
Municipal Permit Support		354d	24-Sep-15	24-Feb-17
A1830	Municipal Permit Coordination / Support	354d	24-Sep-15	24-Feb-17
Local Permit Support		354d	24-Sep-15	24-Feb-17
A1820	Local Permit Coordination / Support	354d	24-Sep-15	24-Feb-17

Remaining Level of Effort
% Complete
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

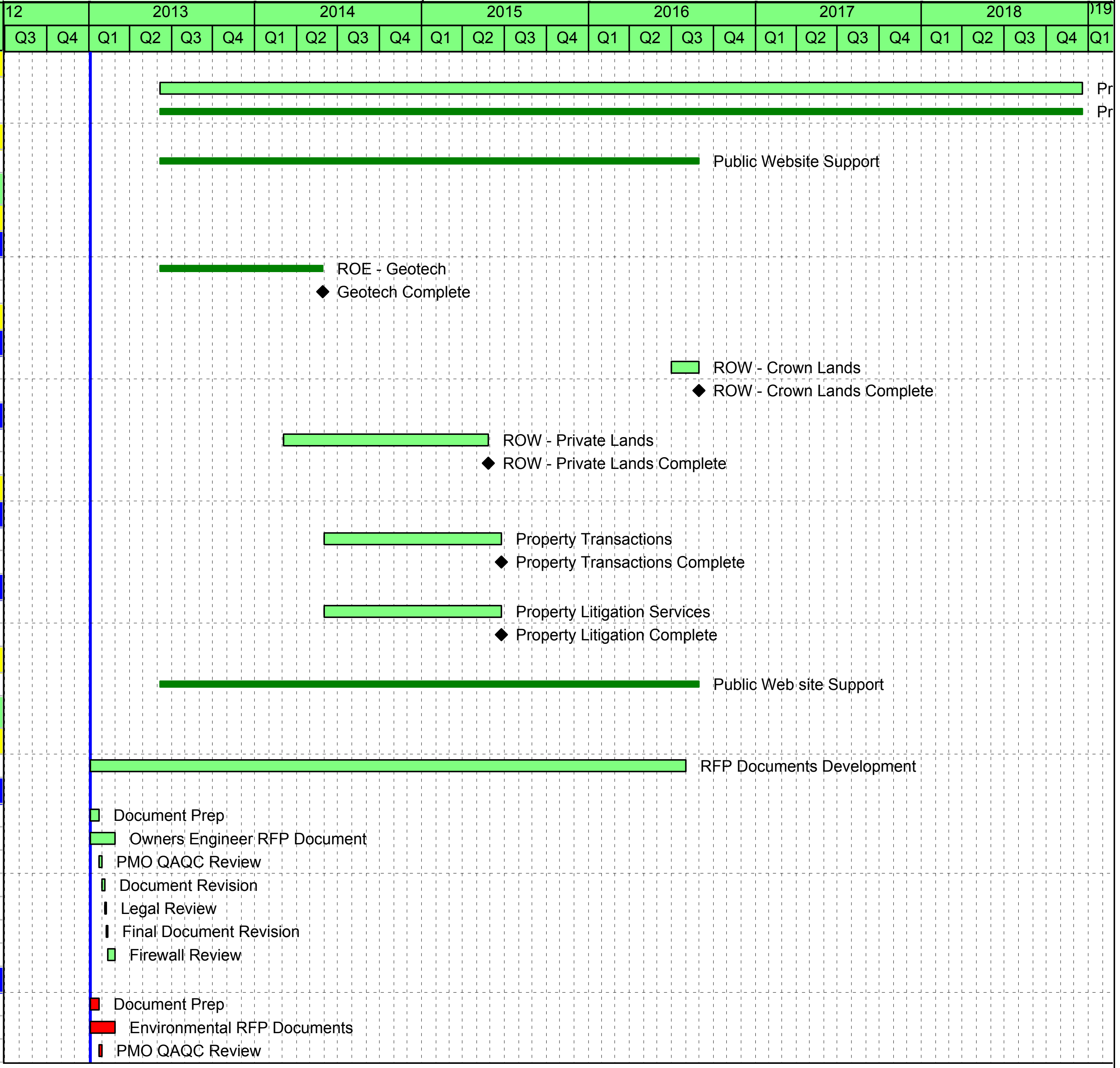
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
Property ROE ROW Support		1377d	07-Jun-13	19-Dec-18
A1810	Property - ROE / ROW Support	1377d	07-Jun-13	19-Dec-18
A64110	Property Support	1377d	07-Jun-13	19-Dec-18
Public Website Support		806d	06-Jun-13	31-Aug-16
A1800	Public Website Support	806d	06-Jun-13	31-Aug-16
Property		806d	06-Jun-13	31-Aug-16
Right of Entry		243d	07-Jun-13	30-May-14
Geotech		243d	07-Jun-13	30-May-14
A1900	ROE - Geotech	243d	07-Jun-13	30-May-14
A63050	Geotech Complete	0d		30-May-14
Right of Way		622d	05-Mar-14	31-Aug-16
Crown Lands		42d	30-Jun-16	31-Aug-16
A1880	ROW - Crown Lands	42d	30-Jun-16	31-Aug-16
A63060	ROW - Crown Lands Complete	0d		31-Aug-16
Private Lands		306d	05-Mar-14	28-May-15
A2090	ROW - Private Lands	306d	05-Mar-14	28-May-15
A63070	ROW - Private Lands Complete	0d		28-May-15
Property Acquisition Services		266d	02-Jun-14	25-Jun-15
Property Transaction Services		266d	02-Jun-14	25-Jun-15
A2160	Property Transactions	266d	02-Jun-14	25-Jun-15
A63080	Property Transactions Complete	0d		25-Jun-15
Property Litigation Services		266d	02-Jun-14	25-Jun-15
A2230	Property Litigation Services	266d	02-Jun-14	25-Jun-15
A63090	Property Litigation Complete	0d		25-Jun-15
Public Website Support		806d	06-Jun-13	31-Aug-16
A1840	Public Web site Support	806d	06-Jun-13	31-Aug-16
Procurement		1031d	04-Jan-13	24-Feb-17
RFP Documents		891d	04-Jan-13	03-Aug-16
A64120	RFP Documents Development	891d	04-Jan-13	03-Aug-16
Owners Engineer RFP Document Development		38d	04-Jan-13	28-Feb-13
A49260	Document Prep	15d	04-Jan-13	25-Jan-13
A64130	Owners Engineer RFP Document	38d	04-Jan-13	28-Feb-13
A49310	PMO QAQC Review	3d	25-Jan-13	30-Jan-13
A49300	Document Revision	3d	30-Jan-13	04-Feb-13
A49280	Legal Review	4d	04-Feb-13	08-Feb-13
A49270	Final Document Revision	3d	08-Feb-13	13-Feb-13
A49290	Firewall Review	10d	13-Feb-13	28-Feb-13
Environmental Consultant RFP Document Development		37d	04-Jan-13	27-Feb-13
A49320	Document Prep	15d	04-Jan-13	25-Jan-13
A64150	Environmental RFP Documents	37d	04-Jan-13	27-Feb-13
A49370	PMO QAQC Review	3d	25-Jan-13	30-Jan-13



🟩 Remaining Level of Effort ▬ % Complete

▬ Actual Level of Effort

🟦 Actual Work

🟩 Remaining Work

🟥 Critical Remaining Work

◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

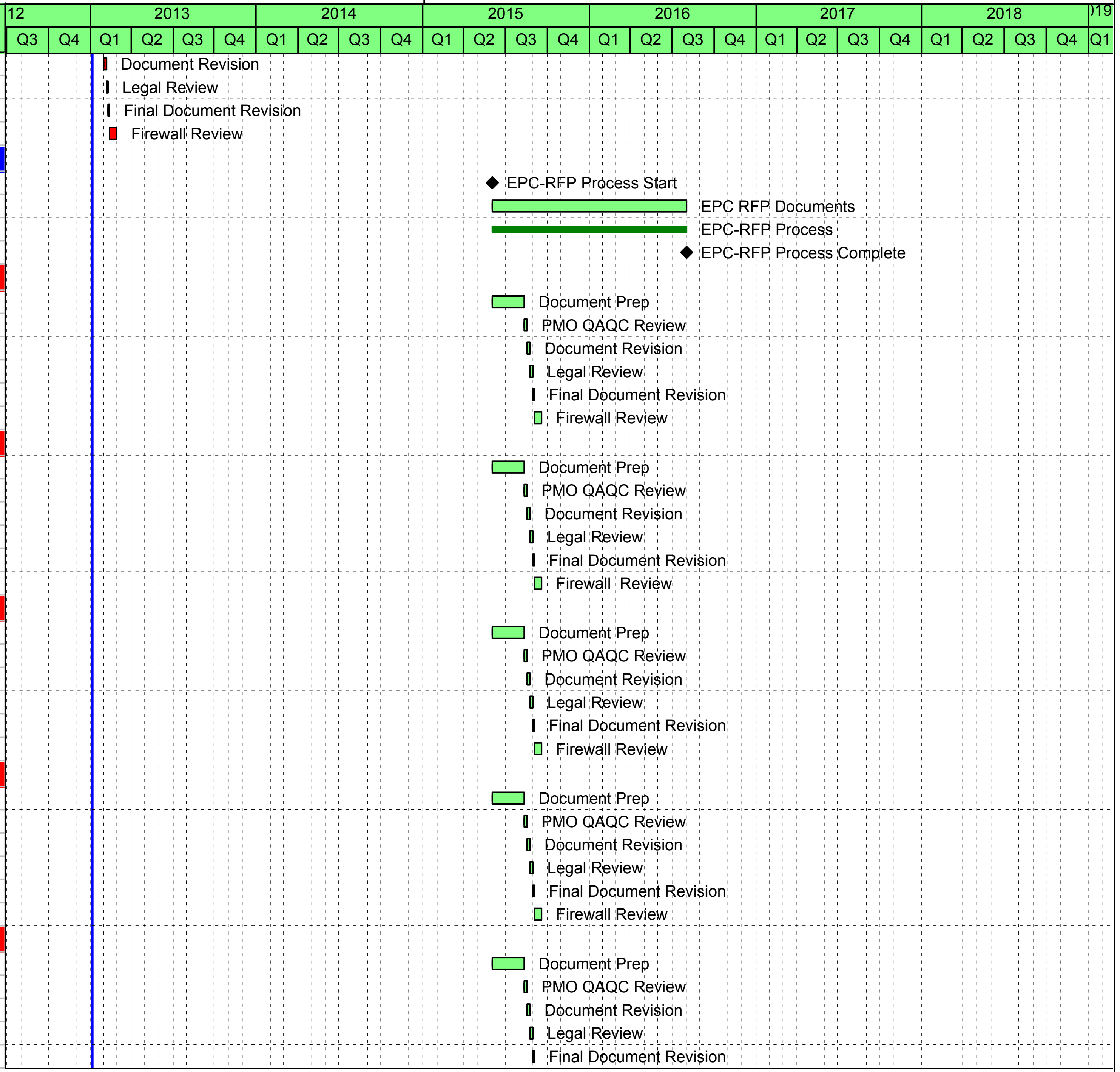
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
A49360	Document Revision	3d	30-Jan-13	04-Feb-13
A49340	Legal Review	3d	04-Feb-13	07-Feb-13
A49330	Final Document Revision	3d	07-Feb-13	12-Feb-13
A49350	Firewall Review	10d	12-Feb-13	27-Feb-13
EPC RFP Document Development		**293d**	**01-Jun-15**	**03-Aug-16**
EPC-RFP-0000	EPC-RFP Process Start	0d	01-Jun-15	
A64140	EPC RFP Documents	293d	01-Jun-15	03-Aug-16
EPC-RFP-1000	EPC-RFP Process	293d	01-Jun-15	03-Aug-16
EPC-RFP-2000	EPC-RFP Process Complete	0d		03-Aug-16
Group 1 (OE - Exhibit A, Sections 1, 2, 4, 13, 21, 23)		**75d**	**01-Jun-15**	**17-Sep-15**
G-1- 1000	Document Prep	50d	01-Jun-15	12-Aug-15
G-1- 1010	PMO QAQC Review	5d	12-Aug-15	19-Aug-15
G-1- 1020	Document Revision	3d	19-Aug-15	24-Aug-15
G-1- 1030	Legal Review	5d	24-Aug-15	31-Aug-15
G-1- 1040	Final Document Revision	2d	31-Aug-15	02-Sep-15
G-1- 1050	Firewall Review	10d	02-Sep-15	17-Sep-15
Group 2 (MAT - Exhibit D, G, H, R) (Contract T&C)		**75d**	**01-Jun-15**	**17-Sep-15**
G-2- 1000	Document Prep	50d	01-Jun-15	12-Aug-15
G-2- 1010	PMO QAQC Review	5d	12-Aug-15	19-Aug-15
G-2- 1020	Document Revision	3d	19-Aug-15	24-Aug-15
G-2- 1030	Legal Review	5d	24-Aug-15	31-Aug-15
G-2- 1040	Final Document Revision	2d	31-Aug-15	02-Sep-15
G-2- 1050	Firewall Review	10d	02-Sep-15	17-Sep-15
Group 3 (MAT - Exhibit E, F, I, J, W)		**75d**	**01-Jun-15**	**17-Sep-15**
G-3- 1000	Document Prep	50d	01-Jun-15	12-Aug-15
G-3- 1010	PMO QAQC Review	5d	12-Aug-15	19-Aug-15
G-3- 1020	Document Revision	3d	19-Aug-15	24-Aug-15
G-3- 1030	Legal Review	5d	24-Aug-15	31-Aug-15
G-3- 1040	Final Document Revision	2d	31-Aug-15	02-Sep-15
G-3- 1050	Firewall Review	10d	02-Sep-15	17-Sep-15
Group 4 (MAT - Exhibit M, N, O, P, Q, S, T, U, V, Z)		**75d**	**01-Jun-15**	**17-Sep-15**
G-4- 1000	Document Prep	50d	01-Jun-15	12-Aug-15
G-4- 1010	PMO QAQC Review	5d	12-Aug-15	19-Aug-15
G-4- 1020	Document Revision	3d	19-Aug-15	24-Aug-15
G-4- 1030	Legal Review	5d	24-Aug-15	31-Aug-15
G-4- 1040	Final Document Revision	2d	31-Aug-15	02-Sep-15
G-4- 1050	Firewall Review	10d	02-Sep-15	17-Sep-15
Group 5 (MAT - Sections 5, 8, 12, 14, 16, 17, 18, 19, 22)		**75d**	**01-Jun-15**	**17-Sep-15**
G-5- 1000	Document Prep	50d	01-Jun-15	12-Aug-15
G-5- 1010	PMO QAQC Review	5d	12-Aug-15	19-Aug-15
G-5- 1020	Document Revision	3d	19-Aug-15	24-Aug-15
G-5- 1030	Legal Review	5d	24-Aug-15	31-Aug-15
G-5- 1040	Final Document Revision	2d	31-Aug-15	02-Sep-15



🟩	Remaining Level of Effort
▬	% Complete
▬	Actual Level of Effort
🟦	Actual Work
🟩	Remaining Work
🟥	Critical Remaining Work
◆ ◆	Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN
TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

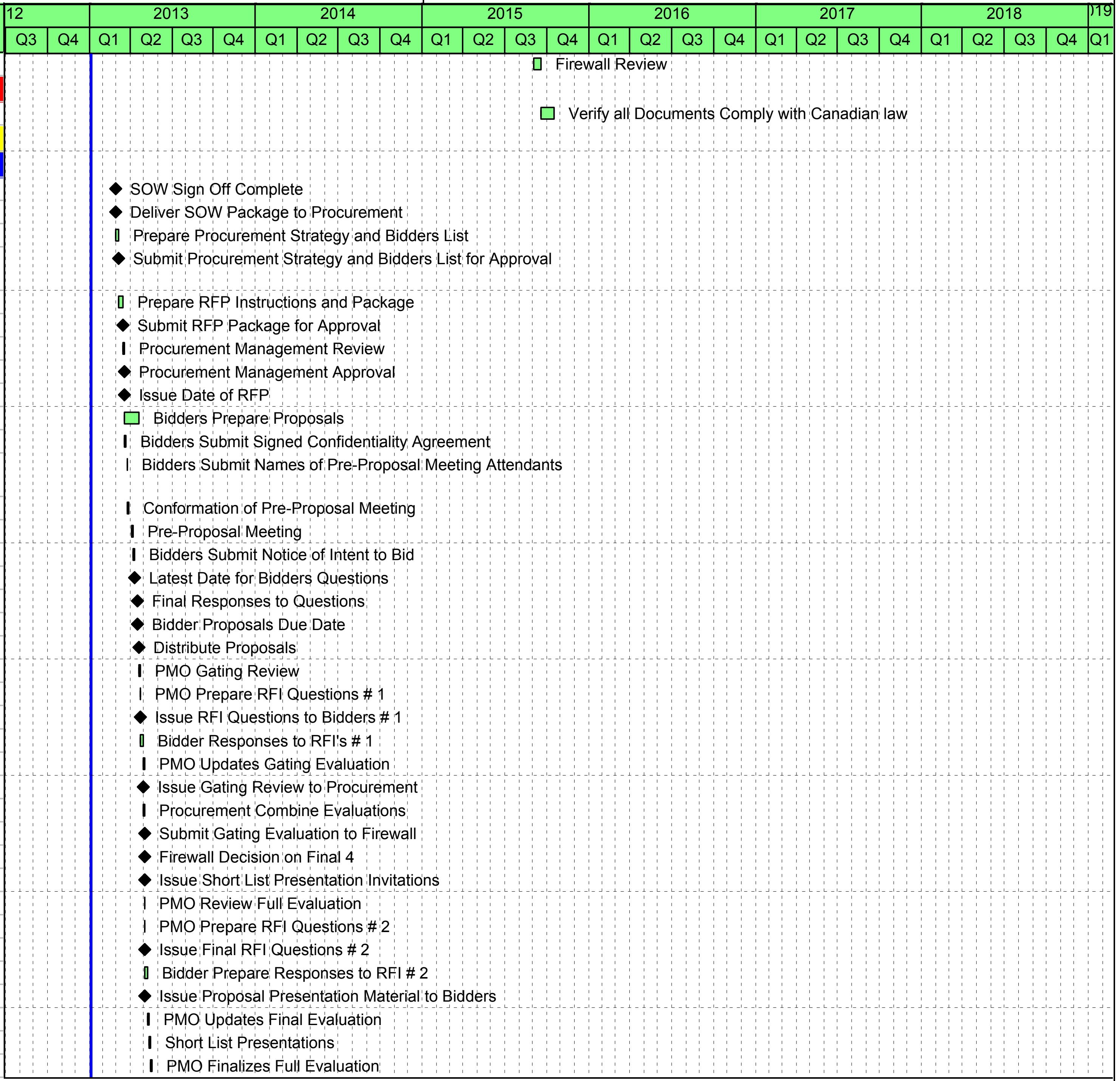
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
G-5- 1050	Firewall Review	10d	02-Sep-15	17-Sep-15
Verify/Modify RFP Documents to Conform to Canadian Law		20d	17-Sep-15	16-Oct-15
EPC-RFP-9000	Verify all Documents Comply with Canadian law	20d	17-Sep-15	16-Oct-15
Procurement Bid Process		994d	27-Feb-13	24-Feb-17
Owners Engineer Bid Process		72d	28-Feb-13	13-Jun-13
A63660	SOW Sign Off Complete	0d		28-Feb-13
A63670	Deliver SOW Package to Procurement	0d	28-Feb-13	
A63680	Prepare Procurement Strategy and Bidders List	5d	28-Feb-13	07-Mar-13
A63690	Submit Procurement Strategy and Bidders List for Approval	0d		07-Mar-13
A63700	Prepare RFP Instructions and Package	5d	07-Mar-13	14-Mar-13
A63710	Submit RFP Package for Approval	0d	14-Mar-13	
A63720	Procurement Management Review	2d	14-Mar-13	18-Mar-13
A63730	Procurement Management Approval	0d		18-Mar-13
A63740	Issue Date of RFP	0d	18-Mar-13	
A63750	Bidders Prepare Proposals	20d	19-Mar-13	18-Apr-13
A63760	Bidders Submit Signed Confidentiality Agreement	1d	20-Mar-13	21-Mar-13
A63770	Bidders Submit Names of Pre-Proposal Meeting Attendants	1d	25-Mar-13	26-Mar-13
A63780	Conformation of Pre-Proposal Meeting	1d	26-Mar-13	27-Mar-13
A63790	Pre-Proposal Meeting	1d	05-Apr-13	08-Apr-13
A63800	Bidders Submit Notice of Intent to Bid	1d	08-Apr-13	09-Apr-13
A63810	Latest Date for Bidders Questions	0d		09-Apr-13
A63820	Final Responses to Questions	0d		16-Apr-13
A63830	Bidder Proposals Due Date	0d	17-Apr-13	
A63840	Distribute Proposals	0d	18-Apr-13	
A63850	PMO Gating Review	2d	18-Apr-13	22-Apr-13
A63860	PMO Prepare RFI Questions # 1	1d	22-Apr-13	23-Apr-13
A63870	Issue RFI Questions to Bidders # 1	0d	23-Apr-13	
A63880	Bidder Responses to RFI's # 1	5d	23-Apr-13	30-Apr-13
A63890	PMO Updates Gating Evaluation	1d	30-Apr-13	01-May-13
A63900	Issue Gating Review to Procurement	0d		30-Apr-13
A63910	Procurement Combine Evaluations	1d	30-Apr-13	01-May-13
A63920	Submit Gating Evaluation to Firewall	0d		01-May-13
A63930	Firewall Decision on Final 4	0d		01-May-13
A63940	Issue Short List Presentation Invitations	0d	01-May-13	
A63950	PMO Review Full Evaluation	1d	01-May-13	02-May-13
A63960	PMO Prepare RFI Questions # 2	1d	02-May-13	03-May-13
A63970	Issue Final RFI Questions # 2	0d	03-May-13	
A63980	Bidder Prepare Responses to RFI # 2	5d	03-May-13	10-May-13
A63990	Issue Proposal Presentation Material to Bidders	0d	03-May-13	
A64000	PMO Updates Final Evaluation	1d	10-May-13	13-May-13
A64010	Short List Presentations	3d	13-May-13	16-May-13
A64020	PMO Finalizes Full Evaluation	1d	16-May-13	17-May-13



🟩	Remaining Level of Effort	▬	% Complete
▬	Actual Level of Effort		
🟦	Actual Work		
🟩	Remaining Work		
🟥	Critical Remaining Work		
◆ ◆	Milestone		

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

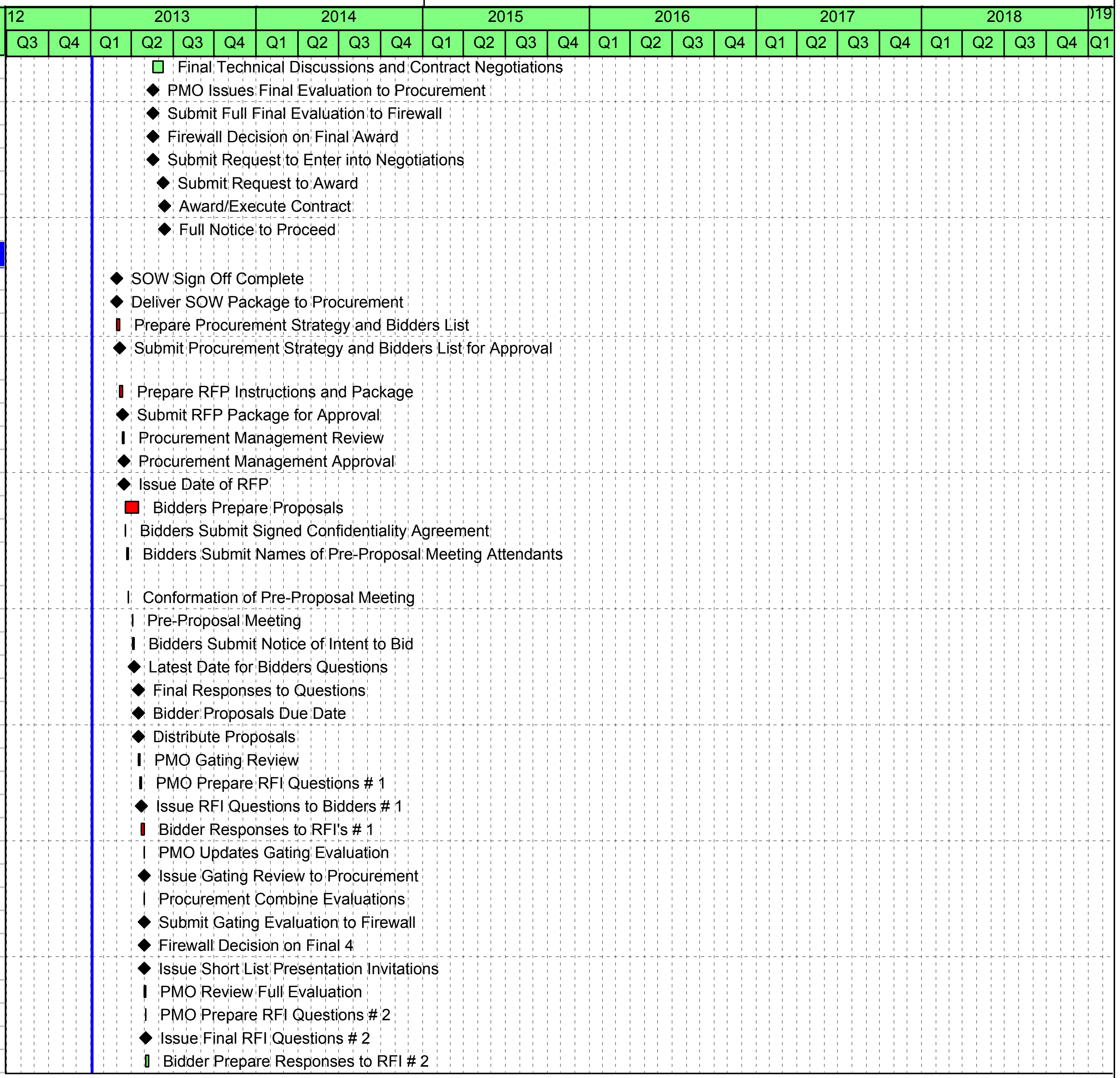
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
A64030	Final Technical Discussions and Contract Negotiations	15d	17-May-13	10-Jun-13
A64040	PMO Issues Final Evaluation to Procurement	0d		17-May-13
A64050	Submit Full Final Evaluation to Firewall	0d		17-May-13
A64060	Firewall Decision on Final Award	0d		17-May-13
A64070	Submit Request to Enter into Negotiations	0d	17-May-13	
A64080	Submit Request to Award	0d		10-Jun-13
A64090	Award/Execute Contract	0d		12-Jun-13
A64100	Full Notice to Proceed	0d		13-Jun-13
Environmental Consultant Bid Process		**69d**	**27-Feb-13**	**07-Jun-13**
A63100	SOW Sign Off Complete	0d		27-Feb-13
A63110	Deliver SOW Package to Procurement	0d	27-Feb-13	
A63120	Prepare Procurement Strategy and Bidders List	5d	27-Feb-13	06-Mar-13
A63130	Submit Procurement Strategy and Bidders List for Approval	0d		06-Mar-13
A63140	Prepare RFP Instructions and Package	5d	06-Mar-13	13-Mar-13
A63150	Submit RFP Package for Approval	0d	13-Mar-13	
A63160	Procurement Management Review	2d	13-Mar-13	15-Mar-13
A63170	Procurement Management Approval	0d		15-Mar-13
A63190	Issue Date of RFP	0d	15-Mar-13	
A63180	Bidders Prepare Proposals	20d	18-Mar-13	17-Apr-13
A63200	Bidders Submit Signed Confidentiality Agreement	1d	19-Mar-13	20-Mar-13
A63210	Bidders Submit Names of Pre-Proposal Meeting Attendants	1d	22-Mar-13	25-Mar-13
A63220	Conformation of Pre-Proposal Meeting	1d	25-Mar-13	26-Mar-13
A63230	Pre-Proposal Meeting	1d	04-Apr-13	05-Apr-13
A63240	Bidders Submit Notice of Intent to Bid	1d	05-Apr-13	08-Apr-13
A63260	Latest Date for Bidders Questions	0d		08-Apr-13
A63270	Final Responses to Questions	0d		15-Apr-13
A63280	Bidder Proposals Due Date	0d	16-Apr-13	
A63290	Distribute Proposals	0d	17-Apr-13	
A63310	PMO Gating Review	2d	17-Apr-13	19-Apr-13
A63330	PMO Prepare RFI Questions # 1	1d	19-Apr-13	22-Apr-13
A63340	Issue RFI Questions to Bidders # 1	0d	22-Apr-13	
A63350	Bidder Responses to RFI's # 1	5d	22-Apr-13	29-Apr-13
A63360	PMO Updates Gating Evaluation	1d	29-Apr-13	30-Apr-13
A63380	Issue Gating Review to Procurement	0d		29-Apr-13
A63390	Procurement Combine Evaluations	1d	29-Apr-13	30-Apr-13
A63400	Submit Gating Evaluation to Firewall	0d		30-Apr-13
A63410	Firewall Decision on Final 4	0d		30-Apr-13
A63420	Issue Short List Presentation Invitations	0d	30-Apr-13	
A63440	PMO Review Full Evaluation	1d	30-Apr-13	01-May-13
A63460	PMO Prepare RFI Questions # 2	1d	01-May-13	02-May-13
A63470	Issue Final RFI Questions # 2	0d	02-May-13	
A63480	Bidder Prepare Responses to RFI # 2	5d	02-May-13	09-May-13



🟩 Remaining Level of Effort — % Complete

🟦 Actual Level of Effort

🟦 Actual Work

🟩 Remaining Work

🟥 Critical Remaining Work

◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

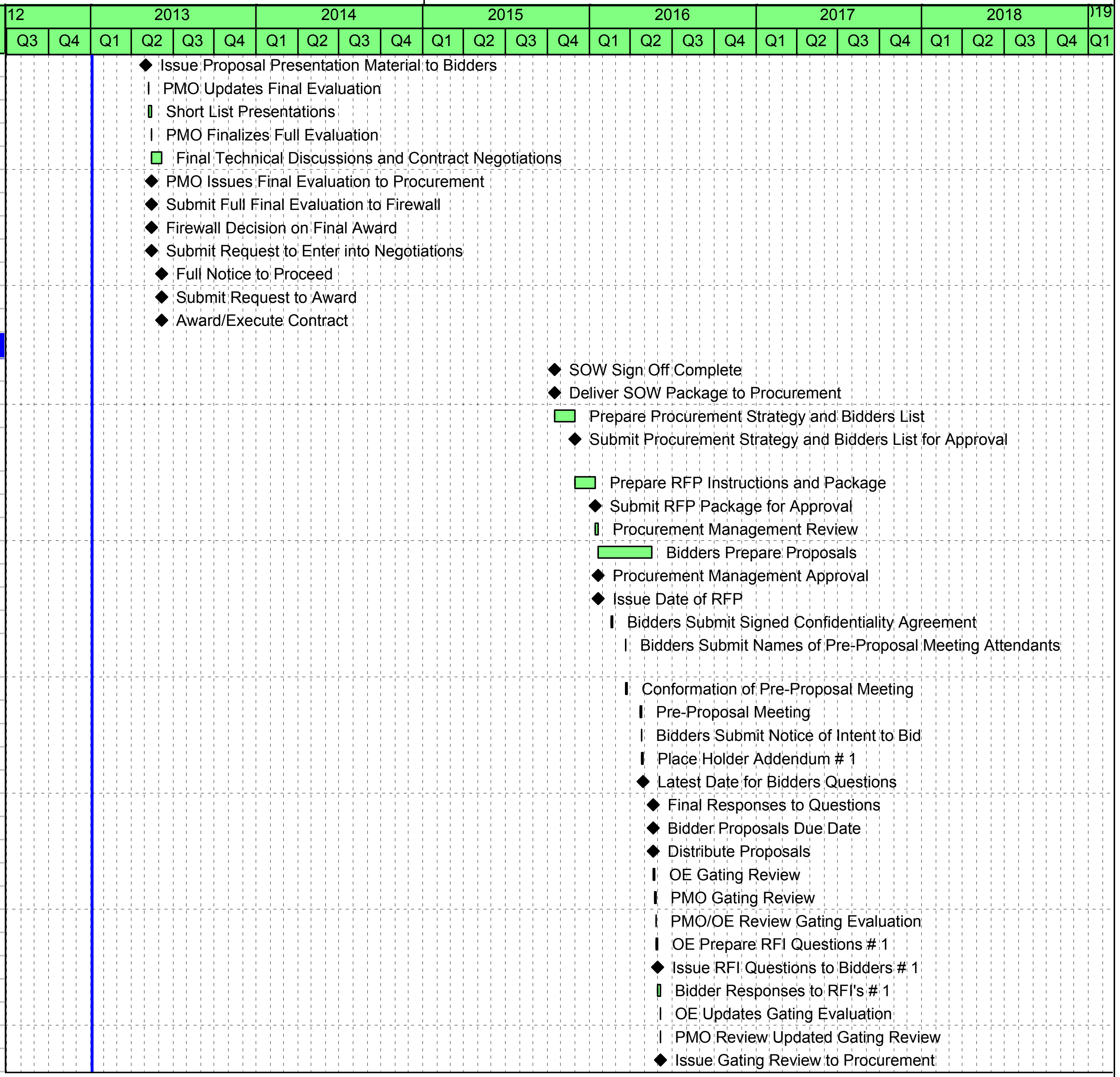
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
A63490	Issue Proposal Presentation Material to Bidders	0d	02-May-13	
A63500	PMO Updates Final Evaluation	1d	09-May-13	10-May-13
A63520	Short List Presentations	3d	10-May-13	15-May-13
A63530	PMO Finalizes Full Evaluation	1d	15-May-13	16-May-13
A63600	Final Technical Discussions and Contract Negotiations	15d	16-May-13	07-Jun-13
A63570	PMO Issues Final Evaluation to Procurement	0d		16-May-13
A63580	Submit Full Final Evaluation to Firewall	0d		16-May-13
A63590	Firewall Decision on Final Award	0d		16-May-13
A63610	Submit Request to Enter into Negotiations	0d	16-May-13	
A63650	Full Notice to Proceed	0d		07-Jun-13
A63620	Submit Request to Award	0d		07-Jun-13
A63630	Award/Execute Contract	0d		07-Jun-13
EPC-OHL Contractor Bid Process		**338d**	**16-Oct-15**	**24-Feb-17**
EPC-PR-1000	SOW Sign Off Complete	0d		16-Oct-15
EPC-PR-1010	Deliver SOW Package to Procurement	0d	16-Oct-15	
EPC-PR-1020	Prepare Procurement Strategy and Bidders List	30d	16-Oct-15	30-Nov-15
EPC-PR-1030	Submit Procurement Strategy and Bidders List for Approval	0d		30-Nov-15
EPC-PR-1040	Prepare RFP Instructions and Package	30d	30-Nov-15	14-Jan-16
EPC-PR-1050	Submit RFP Package for Approval	0d	14-Jan-16	
EPC-PR-1060	Procurement Management Review	5d	14-Jan-16	21-Jan-16
EPC-PR-1080	Bidders Prepare Proposals	80d	21-Jan-16	18-May-16
EPC-PR-1070	Procurement Management Approval	0d		21-Jan-16
EPC-PR-1090	Issue Date of RFP	0d	21-Jan-16	
EPC-PR-1100	Bidders Submit Signed Confidentiality Agreement	1d	19-Feb-16	22-Feb-16
EPC-PR-1110	Bidders Submit Names of Pre-Proposal Meeting Attendants	1d	21-Mar-16	22-Mar-16
EPC-PR-1120	Conformation of Pre-Proposal Meeting	1d	22-Mar-16	23-Mar-16
EPC-PR-1130	Pre-Proposal Meeting	1d	22-Apr-16	25-Apr-16
EPC-PR-1140	Bidders Submit Notice of Intent to Bid	1d	25-Apr-16	26-Apr-16
EPC-PR-1150	Place Holder Addendum # 1	1d	26-Apr-16	27-Apr-16
EPC-PR-1160	Latest Date for Bidders Questions	0d		27-Apr-16
EPC-PR-1170	Final Responses to Questions	0d		19-May-16
EPC-PR-1180	Bidder Proposals Due Date	0d	19-May-16	
EPC-PR-1190	Distribute Proposals	0d	20-May-16	
EPC-PR-1200	OE Gating Review	2d	20-May-16	24-May-16
EPC-PR-1210	PMO Gating Review	2d	24-May-16	26-May-16
EPC-PR-1220	PMO/OE Review Gating Evaluation	1d	26-May-16	27-May-16
EPC-PR-1230	OE Prepare RFI Questions # 1	1d	27-May-16	30-May-16
EPC-PR-1240	Issue RFI Questions to Bidders # 1	0d	30-May-16	
EPC-PR-1250	Bidder Responses to RFI's # 1	5d	30-May-16	06-Jun-16
EPC-PR-1260	OE Updates Gating Evaluation	1d	06-Jun-16	07-Jun-16
EPC-PR-1270	PMO Review Updated Gating Review	1d	06-Jun-16	07-Jun-16
EPC-PR-1280	Issue Gating Review to Procurement	0d		07-Jun-16



🟩 Remaining Level of Effort ▬ % Complete
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

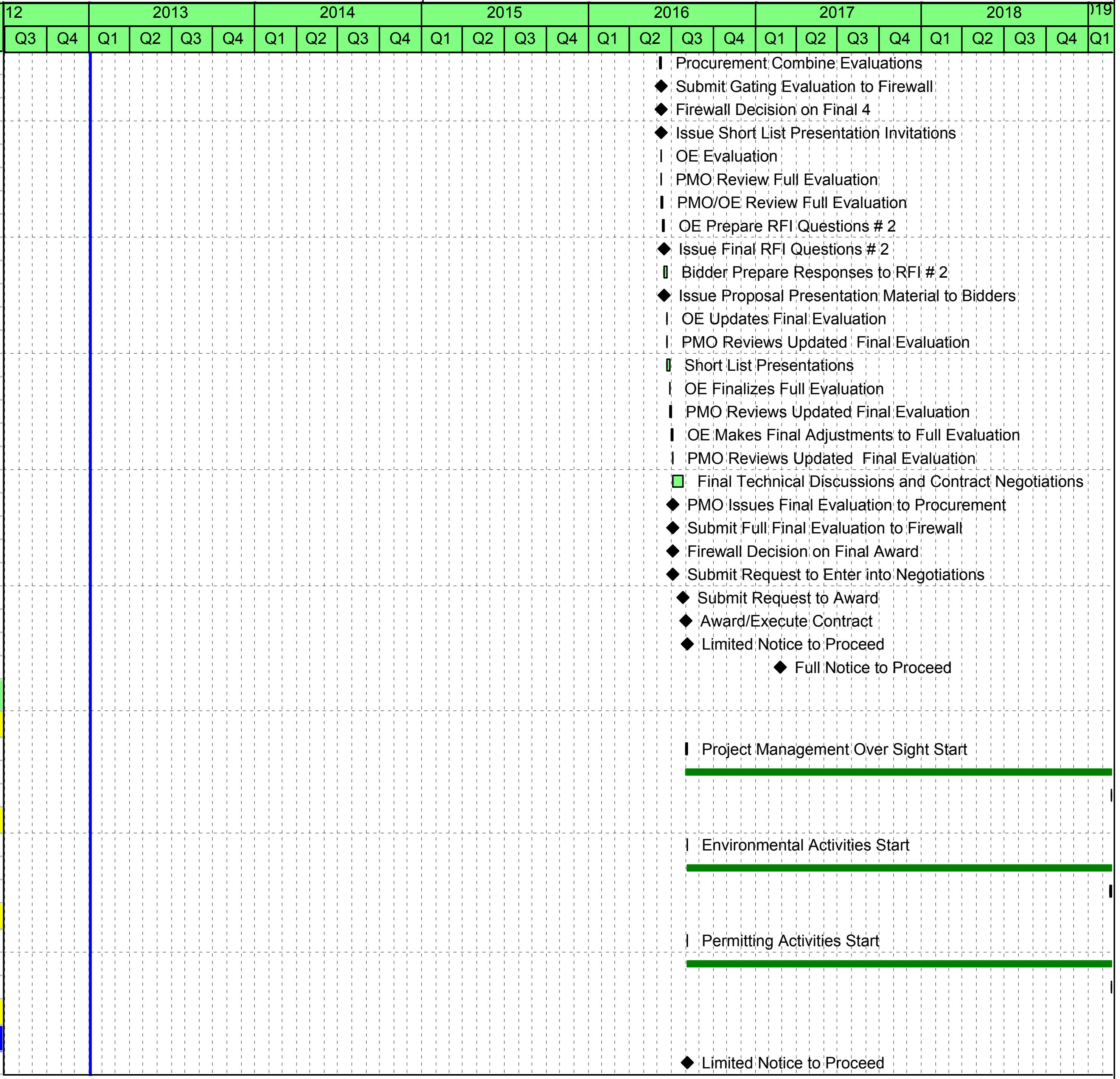
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
EPC-PR-1290	Procurement Combine Evaluations	1d	07-Jun-16	08-Jun-16
EPC-PR-1300	Submit Gating Evaluation to Firewall	0d		08-Jun-16
EPC-PR-1310	Firewall Decision on Final 4	0d		08-Jun-16
EPC-PR-1320	Issue Short List Presentation Invitations	0d	08-Jun-16	
EPC-PR-1330	OE Evaluation	1d	08-Jun-16	09-Jun-16
EPC-PR-1340	PMO Review Full Evaluation	1d	09-Jun-16	10-Jun-16
EPC-PR-1350	PMO/OE Review Full Evaluation	1d	10-Jun-16	13-Jun-16
EPC-PR-1360	OE Prepare RFI Questions # 2	1d	13-Jun-16	14-Jun-16
EPC-PR-1370	Issue Final RFI Questions # 2	0d	14-Jun-16	
EPC-PR-1380	Bidder Prepare Responses to RFI # 2	5d	14-Jun-16	21-Jun-16
EPC-PR-1390	Issue Proposal Presentation Material to Bidders	0d	14-Jun-16	
EPC-PR-1400	OE Updates Final Evaluation	1d	21-Jun-16	22-Jun-16
EPC-PR-1410	PMO Reviews Updated Final Evaluation	1d	22-Jun-16	23-Jun-16
EPC-PR-1420	Short List Presentations	3d	23-Jun-16	28-Jun-16
EPC-PR-1430	OE Finalizes Full Evaluation	1d	28-Jun-16	29-Jun-16
EPC-PR-1440	PMO Reviews Updated Final Evaluation	1d	29-Jun-16	30-Jun-16
EPC-PR-1450	OE Makes Final Adjustments to Full Evaluation	1d	30-Jun-16	04-Jul-16
EPC-PR-1460	PMO Reviews Updated Final Evaluation	1d	04-Jul-16	05-Jul-16
EPC-PR-1500	Final Technical Discussions and Contract Negotiations	15d	05-Jul-16	26-Jul-16
EPC-PR-1470	PMO Issues Final Evaluation to Procurement	0d		05-Jul-16
EPC-PR-1480	Submit Full Final Evaluation to Firewall	0d		05-Jul-16
EPC-PR-1490	Firewall Decision on Final Award	0d		05-Jul-16
EPC-PR-1510	Submit Request to Enter into Negotiations	0d	05-Jul-16	
EPC-PR-1520	Submit Request to Award	0d		26-Jul-16
EPC-PR-1530	Award/Execute Contract	0d		03-Aug-16
EPC-PR-1540	Limited Notice to Proceed	0d	04-Aug-16	
EPC-PR-1550	Full Notice to Proceed	0d		24-Feb-17
EPC Construction		636d	03-Aug-16	21-Feb-19
Project Management Oversight		636d	03-Aug-16	21-Feb-19
PM-OS-1000	Project Management Over Sight Start	1d	03-Aug-16	04-Aug-16
PM-OS-1010	Project Management Over Sight Activities	636d	03-Aug-16	21-Feb-19
PM-OS-1020	Project Management Over Sight Complete	1d	20-Feb-19	21-Feb-19
Environmental Compliance		634d	04-Aug-16	20-Feb-19
EN-OS-1000	Environmental Activities Start	1d	04-Aug-16	05-Aug-16
EN-OS-1010	Environmental Activities	634d	04-Aug-16	20-Feb-19
EN-OS-1020	Environmental Activities Complete	1d	19-Feb-19	20-Feb-19
Permitting Compliance		635d	04-Aug-16	21-Feb-19
PC-OS-1000	Permitting Activities Start	1d	04-Aug-16	05-Aug-16
PC-OS-1020	Permitting Activities	635d	04-Aug-16	21-Feb-19
PC-OS-1010	Permitting Activities Complete	1d	20-Feb-19	21-Feb-19
Transmission Lines Construction		634d	04-Aug-16	20-Feb-19
Project Milestones		634d	04-Aug-16	20-Feb-19
PRJ-MS-1000	Limited Notice to Proceed	0d	04-Aug-16	



🟩 Remaining Level of Effort
▬ % Complete
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

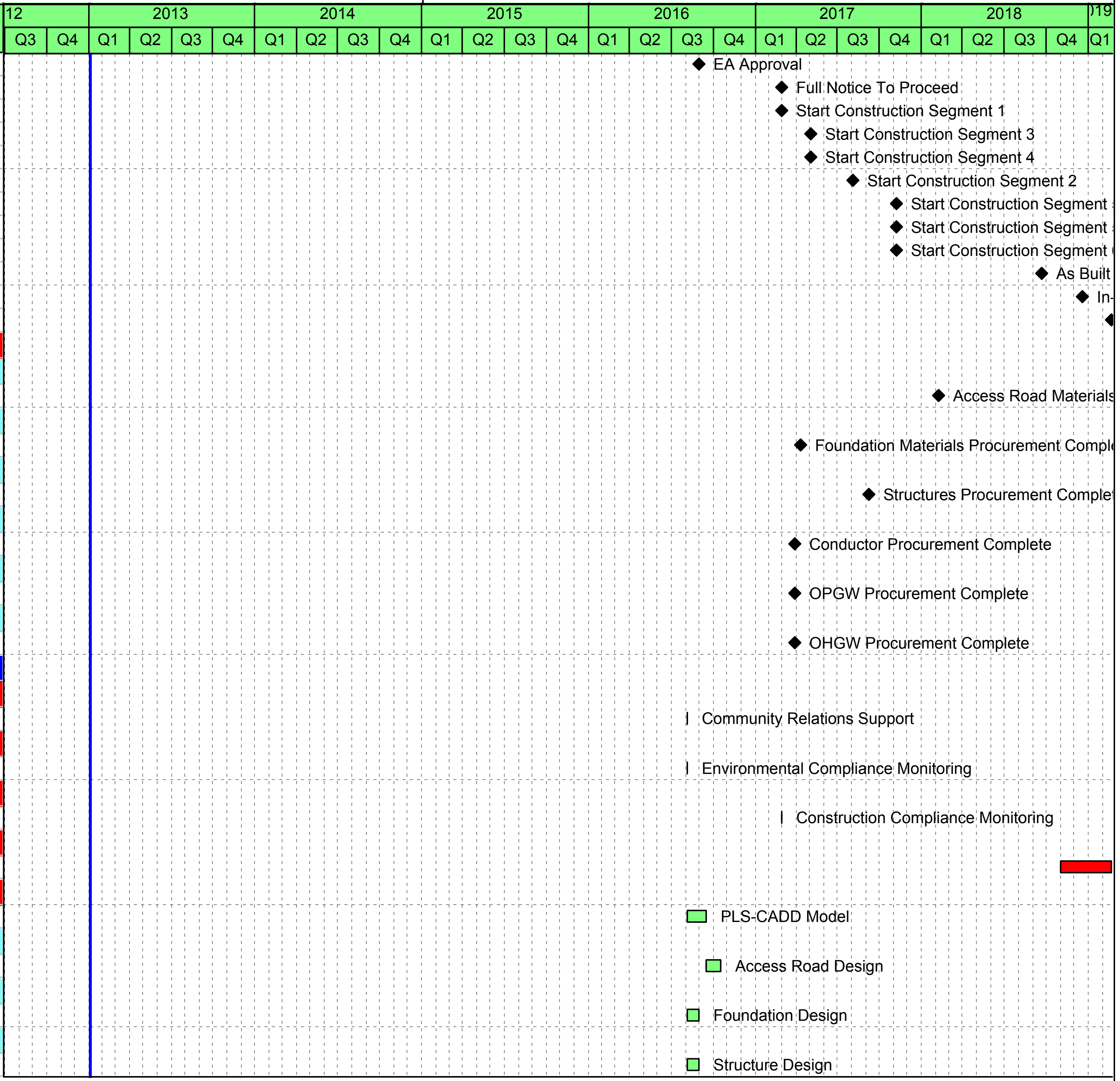
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
PRJ-MS-0000	EA Approval	0d	01-Sep-16	
PRJ-MS-1010	Full Notice To Proceed	0d	27-Feb-17	
PRJ-MS-1020	Start Construction Segment 1	0d	27-Feb-17	
PRJ-MS-1040	Start Construction Segment 3	0d	03-May-17	
PRJ-MS-1050	Start Construction Segment 4	0d	03-May-17	
PRJ-MS-1030	Start Construction Segment 2	0d	04-Aug-17	
PRJ-MS-1060	Start Construction Segment 5.1	0d	08-Nov-17	
PRJ-MS-1070	Start Construction Segment 5.2	0d	08-Nov-17	
PRJ-MS-1080	Start Construction Segment 6	0d	08-Nov-17	
PRJ-MS-1090	As Built Documents Complete	0d		20-Sep-18
PRJ-MS-1100	In-Service Date	0d		19-Dec-18
PRJ-MS-1110	Final Project Completion Date	0d		20-Feb-19
Procurement Milestones		213d	28-Mar-17	06-Feb-18
Access Roads		0d	06-Feb-18	06-Feb-18
A60560	Access Road Materials Procurement Complete	0d		06-Feb-18
Foundations		0d	11-Apr-17	11-Apr-17
A60570	Foundation Materials Procurement Complete	0d		11-Apr-17
Structures		0d	06-Sep-17	06-Sep-17
PR190	Structures Procurement Complete	0d		06-Sep-17
Conductors		0d	28-Mar-17	28-Mar-17
PR320	Conductor Procurement Complete	0d		28-Mar-17
OPGW		0d	28-Mar-17	28-Mar-17
PR410	OPGW Procurement Complete	0d		28-Mar-17
OHWG		0d	28-Mar-17	28-Mar-17
PR350	OHGW Procurement Complete	0d		28-Mar-17
Project Common		634d	04-Aug-16	20-Feb-19
Community Relations		1d	04-Aug-16	05-Aug-16
A60550	Community Relations Support	1d	04-Aug-16	05-Aug-16
Environmental Common		1d	04-Aug-16	05-Aug-16
A60530	Environmental Compliance Monitoring	1d	04-Aug-16	05-Aug-16
Permits Common		1d	27-Feb-17	27-Feb-17
A60540	Construction Compliance Monitoring	1d	27-Feb-17	27-Feb-17
General		75d	02-Nov-18	20-Feb-19
SM1310	Punch List	75d	02-Nov-18	20-Feb-19
Engineering Common		110d	04-Aug-16	13-Jan-17
A60350	PLS-CADD Model	30d	04-Aug-16	16-Sep-16
Access Roads		20d	16-Sep-16	17-Oct-16
A60360	Access Road Design	20d	16-Sep-16	17-Oct-16
Foundations		20d	04-Aug-16	01-Sep-16
A60370	Foundation Design	20d	04-Aug-16	01-Sep-16
Structures		110d	04-Aug-16	13-Jan-17
EN099	Structure Design	20d	04-Aug-16	01-Sep-16



- Remaining Level of Effort
- % Complete
- Actual Level of Effort
- Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

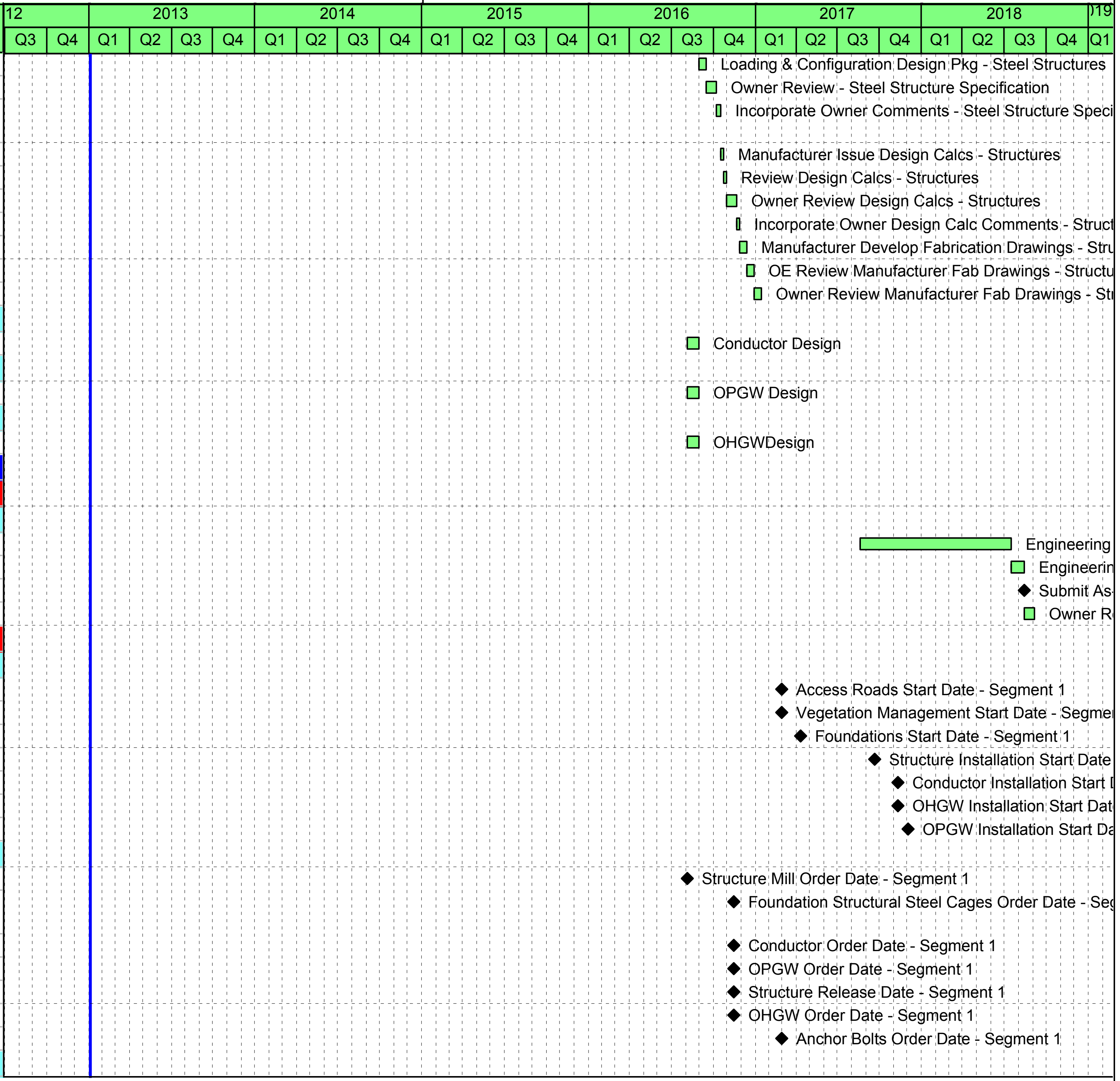
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
EN100	Loading & Configuration Design Pkg - Steel Structures	10d	01-Sep-16	16-Sep-16
EN103	Owner Review - Steel Structure Specification	15d	16-Sep-16	07-Oct-16
EN104	Incorporate Owner Comments - Steel Structure Specification	5d	07-Oct-16	17-Oct-16
EN105	Manufacturer Issue Design Calcs - Structures	5d	17-Oct-16	24-Oct-16
EN106	Review Design Calcs - Structures	5d	24-Oct-16	31-Oct-16
EN107	Owner Review Design Calcs - Structures	15d	31-Oct-16	22-Nov-16
EN108	Incorporate Owner Design Calc Comments - Structures	5d	22-Nov-16	29-Nov-16
EN109	Manufacturer Develop Fabrication Drawings - Structures	10d	29-Nov-16	13-Dec-16
EN110	OE Review Manufacturer Fab Drawings - Structures	10d	13-Dec-16	29-Dec-16
EN111	Owner Review Manufacturer Fab Drawings - Structures	10d	29-Dec-16	13-Jan-17
Conductors		20d	04-Aug-16	01-Sep-16
A60390	Conductor Design	20d	04-Aug-16	01-Sep-16
OPGW		20d	04-Aug-16	01-Sep-16
A60430	OPGW Design	20d	04-Aug-16	01-Sep-16
OHWG		20d	04-Aug-16	01-Sep-16
A60440	OHGWDesign	20d	04-Aug-16	01-Sep-16
Segment 1 Thunder Bay - Nipigon River (85 km)		519d	04-Aug-16	05-Sep-18
Project Management		260d	18-Aug-17	05-Sep-18
Project Support		260d	18-Aug-17	05-Sep-18
S1-ENG-9000	Engineering Construction Support - Segment 1	225d	18-Aug-17	16-Jul-18
S1-ENG-9010	Engineering As-Builts - Segment 1	20d	16-Jul-18	14-Aug-18
S1-ENG-9020	Submit As-Builts - Segment 1	0d		14-Aug-18
S1-ENG-9030	Owner Review As-Builts - Segment 1	15d	14-Aug-18	05-Sep-18
Contractor Milestones Segment 1		484d	04-Aug-16	16-Jul-18
Start Dates		192d	27-Feb-17	01-Dec-17
S1-SD-MS-1010	Access Roads Start Date - Segment 1	0d	27-Feb-17	
S1-SD-MS-1020	Vegetation Management Start Date - Segment 1	0d	27-Feb-17	
S1-SD-MS-1030	Foundations Start Date - Segment 1	0d	12-Apr-17	
S1-SD-MS-1040	Structure Installation Start Date - Segment 1	0d	20-Sep-17	
S1-SD-MS-1050	Conductor Installation Start Date - Segment 1	0d	09-Nov-17	
S1-SD-MS-1060	OHGW Installation Start Date - Segment 1	0d	09-Nov-17	
S1-SD-MS-1070	OPGW Installation Start Date - Segment 1	0d	01-Dec-17	
Order Dates		139d	04-Aug-16	27-Feb-17
S1-OD-MS-1000	Structure Mill Order Date - Segment 1	0d	04-Aug-16	
S1-OD-MS-1020	Foundation Structural Steel Cages Order Date - Segment 1	0d	16-Nov-16	
S1-OD-MS-1030	Conductor Order Date - Segment 1	0d	16-Nov-16	
S1-OD-MS-1040	OPGW Order Date - Segment 1	0d	16-Nov-16	
S1-OD-MS-1050	Structure Release Date - Segment 1	0d	16-Nov-16	
S1-OD-MS-1060	OHGW Order Date - Segment 1	0d	16-Nov-16	
S1-OD-MS-1010	Anchor Bolts Order Date - Segment 1	0d	27-Feb-17	
Received Dates		170d	30-Dec-16	06-Sep-17



🟩	Remaining Level of Effort
▬	% Complete
🟦	Actual Level of Effort
🟦	Actual Work
🟩	Remaining Work
🟥	Critical Remaining Work
◆ ◆	Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

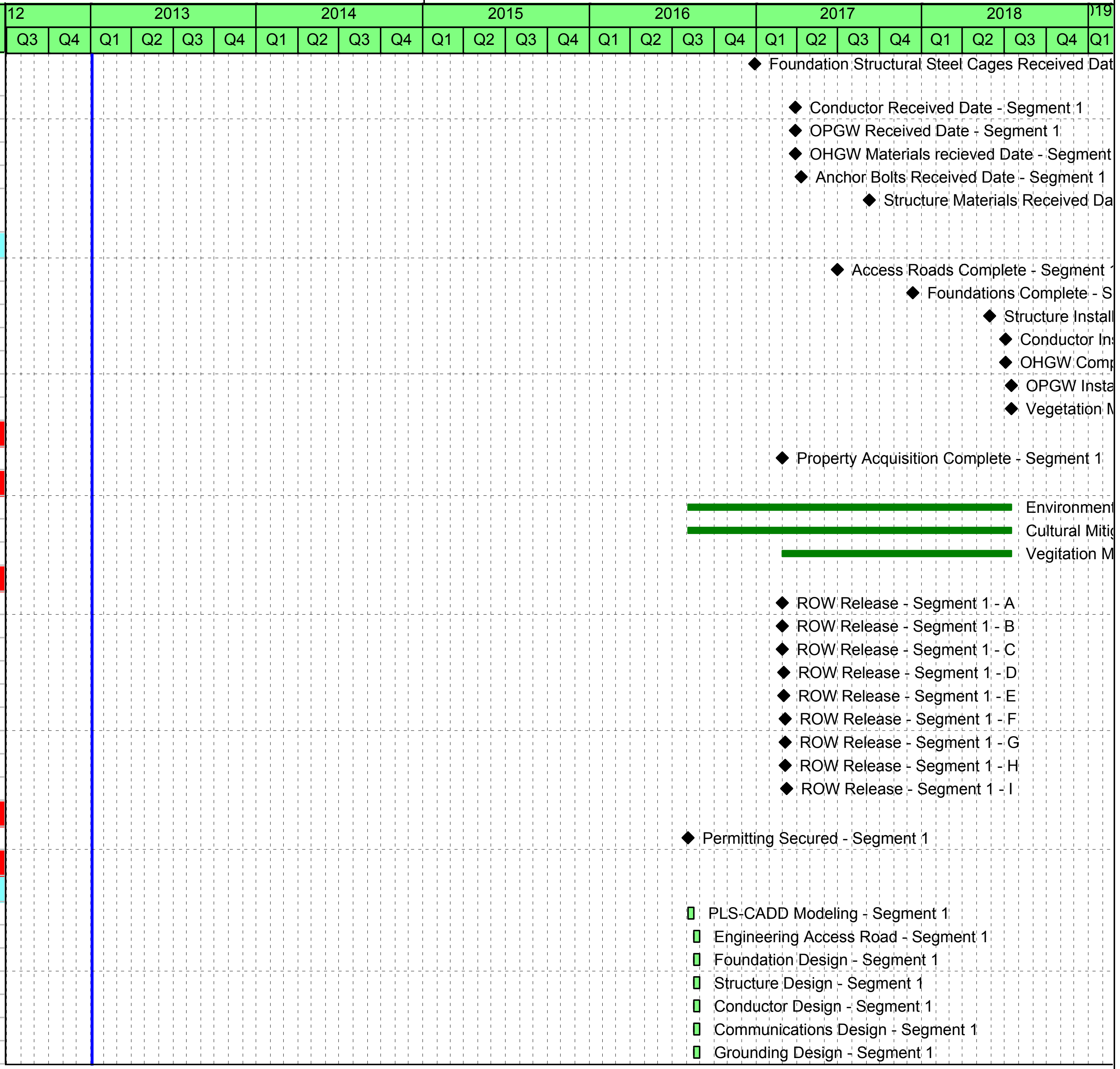
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S1-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segment 1	0d		30-Dec-16
S1-RD-MS-1030	Conductor Received Date - Segment 1	0d		28-Mar-17
S1-RD-MS-1050	OPGW Received Date - Segment 1	0d		28-Mar-17
S1-RD-MS-1040	OHGW Materials recieved Date - Segment 1	0d		28-Mar-17
S1-RD-MS-1010	Anchor Bolts Received Date - Segment 1	0d		11-Apr-17
S1-RD-MS-1060	Structure Materials Received Date - Segment 1 (40weeks)	0d		06-Sep-17
Completion Dates		260d	29-Jun-17	16-Jul-18
S1-CD-MS-1010	Access Roads Complete - Segment 1	0d		29-Jun-17
S1-CD-MS-1020	Foundations Complete - Segment 1	0d		13-Dec-17
S1-CD-MS-1030	Structure Installation Complete - Segment 1	0d		29-May-18
S1-CD-MS-1040	Conductor Installation Complete - Segment 1	0d		04-Jul-18
S1-CD-MS-1050	OHGW Complete - Segment 1	0d		04-Jul-18
S1-CD-MS-1060	OPGW Installation Complete - Segment 1	0d		16-Jul-18
S1-CD-MS-1070	Vegetation Management Complete - Segment 1	0d		16-Jul-18
Property		0d	27-Feb-17	27-Feb-17
S1-PRP-1000	Property Acquisition Complete - Segment 1	0d		27-Feb-17
Environmental		484d	04-Aug-16	16-Jul-18
S1-ENV-1000	Environmental Monitoring- Segment 1	484d	04-Aug-16	16-Jul-18
S1-ENV-1010	Cultural Mitigation - Segment 1	484d	04-Aug-16	16-Jul-18
S1-ENV-1020	Vegitation Management - Segment 1	345d	27-Feb-17	16-Jul-18
Right of Way		8d	27-Feb-17	09-Mar-17
ROW-1A	ROW Release - Segment 1 - A	0d	27-Feb-17	
ROW-1B	ROW Release - Segment 1 - B	0d	28-Feb-17	
ROW-1C	ROW Release - Segment 1 - C	0d	01-Mar-17	
ROW-1D	ROW Release - Segment 1 - D	0d	02-Mar-17	
ROW-1E	ROW Release - Segment 1 - E	0d	03-Mar-17	
ROW-1F	ROW Release - Segment 1 - F	0d	06-Mar-17	
ROW-1G	ROW Release - Segment 1 - G	0d	07-Mar-17	
ROW-1H	ROW Release - Segment 1 - H	0d	08-Mar-17	
ROW-1I	ROW Release - Segment 1 - I	0d	09-Mar-17	
Permitting		0d	04-Aug-16	04-Aug-16
S1-PMT-1000	Permitting Secured - Segment 1	0d		04-Aug-16
Transmission Lines		484d	04-Aug-16	16-Jul-18
Engineering-T-Line		71d	04-Aug-16	16-Nov-16
S1-ENG-1000	PLS-CADD Modeling - Segment 1	10d	04-Aug-16	18-Aug-16
S1-ENG-1010	Engineering Access Road - Segment 1	10d	18-Aug-16	01-Sep-16
S1-ENG-1020	Foundation Design - Segment 1	10d	18-Aug-16	01-Sep-16
S1-ENG-1030	Structure Design - Segment 1	10d	18-Aug-16	01-Sep-16
S1-ENG-1040	Conductor Design - Segment 1	10d	18-Aug-16	01-Sep-16
S1-ENG-1050	Communications Design - Segment 1	10d	18-Aug-16	01-Sep-16
S1-ENG-1060	Grounding Design - Segment 1	10d	18-Aug-16	01-Sep-16



🟩 Remaining Level of Effort ⬛ % Complete
🟦 Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

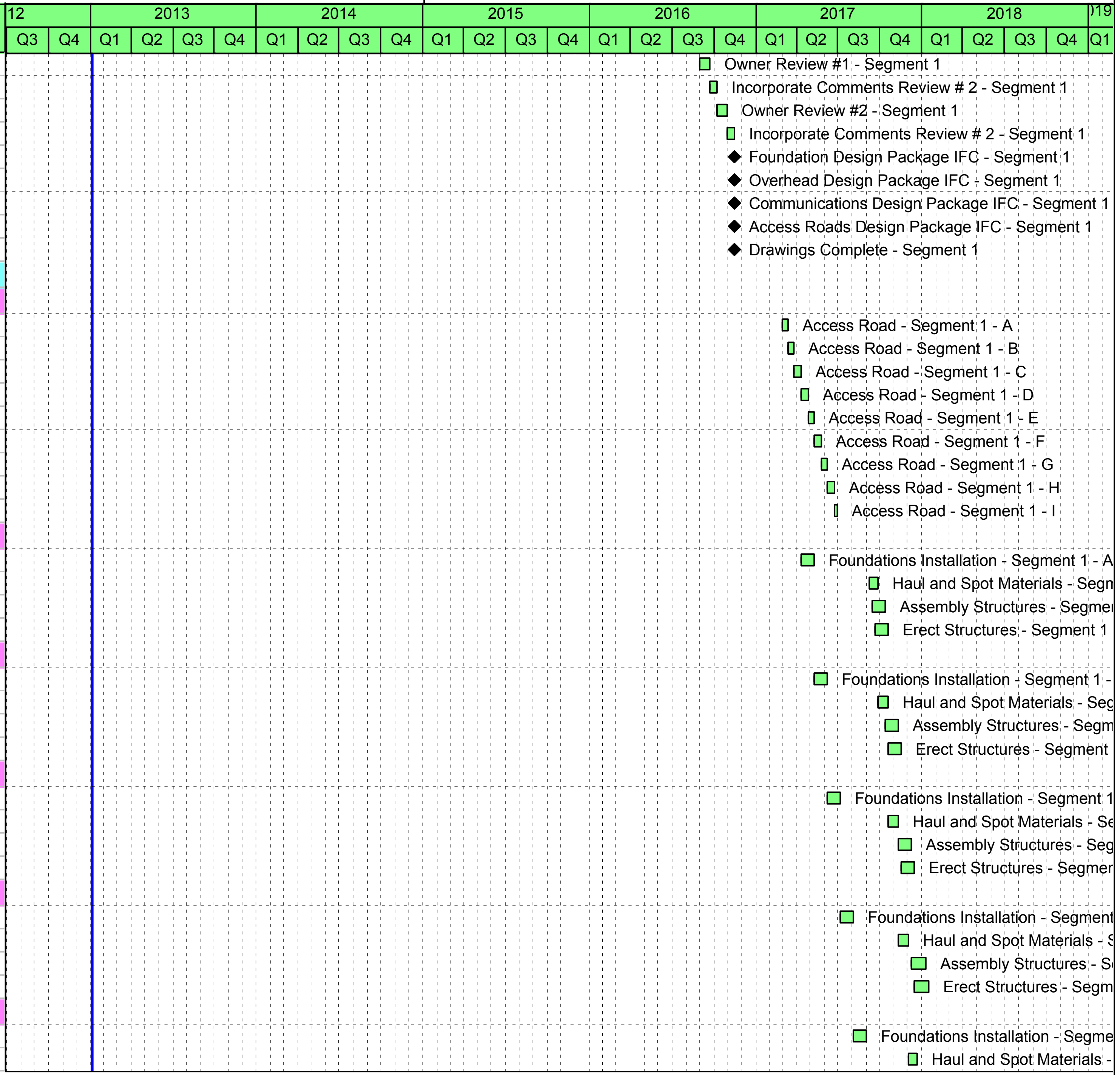
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S1-ENG-1070	Owner Review #1 - Segment 1	15d	01-Sep-16	23-Sep-16
S1-ENG-1080	Incorporate Comments Review # 2 - Segment 1	10d	23-Sep-16	07-Oct-16
S1-ENG-1090	Owner Review #2 - Segment 1	15d	07-Oct-16	31-Oct-16
S1-ENG-1100	Incorporate Comments Review # 2 - Segment 1	10d	31-Oct-16	15-Nov-16
S1-ENG-1120	Foundation Design Package IFC - Segment 1	0d		15-Nov-16
S1-ENG-1130	Overhead Design Package IFC - Segment 1	0d		15-Nov-16
S1-ENG-1140	Communications Design Package IFC - Segment 1	0d		15-Nov-16
S1-ENG-1150	Access Roads Design Package IFC - Segment 1	0d		15-Nov-16
S1-ENG-1160	Drawings Complete - Segment 1	0d		16-Nov-16
Construction-T-Line		345d	27-Feb-17	16-Jul-18
Access Roads		85d	27-Feb-17	29-Jun-17
S1-AR-1000	Access Road - Segment 1 - A	10d	27-Feb-17	13-Mar-17
S1-AR-1010	Access Road - Segment 1 - B	10d	13-Mar-17	27-Mar-17
S1-AR-1020	Access Road - Segment 1 - C	10d	27-Mar-17	12-Apr-17
S1-AR-1030	Access Road - Segment 1 - D	10d	12-Apr-17	26-Apr-17
S1-AR-1040	Access Road - Segment 1 - E	10d	26-Apr-17	10-May-17
S1-AR-1050	Access Road - Segment 1 - F	10d	10-May-17	25-May-17
S1-AR-1060	Access Road - Segment 1 - G	10d	25-May-17	08-Jun-17
S1-AR-1070	Access Road - Segment 1 - H	10d	08-Jun-17	22-Jun-17
S1-AR-1080	Access Road - Segment 1 - I	5d	22-Jun-17	29-Jun-17
Section A		132d	12-Apr-17	19-Oct-17
S1-A-001	Foundations Installation - Segment 1 - A	20d	12-Apr-17	09-May-17
S1-A-002	Haul and Spot Materials - Segment 1 - A	15d	06-Sep-17	27-Sep-17
S1-A-003	Assembly Structures - Segment 1 - A	20d	13-Sep-17	11-Oct-17
S1-A-004	Erect Structures - Segment 1 - A	20d	20-Sep-17	19-Oct-17
Section B		132d	10-May-17	17-Nov-17
S1-B-001	Foundations Installation - Segment 1 - B	20d	10-May-17	07-Jun-17
S1-B-002	Haul and Spot Materials - Segment 1 - B	15d	27-Sep-17	19-Oct-17
S1-B-003	Assembly Structures - Segment 1 - B	20d	11-Oct-17	09-Nov-17
S1-B-004	Erect Structures - Segment 1 - B	20d	19-Oct-17	17-Nov-17
Section C		132d	08-Jun-17	15-Dec-17
S1-C-001	Foundations Installation - Segment 1 - C	20d	08-Jun-17	06-Jul-17
S1-C-002	Haul and Spot Materials - Segment 1 - C	15d	19-Oct-17	09-Nov-17
S1-C-003	Assembly Structures - Segment 1 - C	20d	09-Nov-17	08-Dec-17
S1-C-004	Erect Structures - Segment 1 - C	20d	17-Nov-17	15-Dec-17
Section D		132d	07-Jul-17	17-Jan-18
S1-D-001	Foundations Installation - Segment 1 - D	20d	07-Jul-17	03-Aug-17
S1-D-002	Haul and Spot Materials - Segment 1 - D	15d	09-Nov-17	01-Dec-17
S1-D-003	Assembly Structures - Segment 1 - D	20d	08-Dec-17	10-Jan-18
S1-D-004	Erect Structures - Segment 1 - D	20d	15-Dec-17	17-Jan-18
Section E		132d	04-Aug-17	14-Feb-18
S1-E-001	Foundations Installation - Segment 1 - E	20d	04-Aug-17	01-Sep-17
S1-E-002	Haul and Spot Materials - Segment 1 - E	15d	01-Dec-17	22-Dec-17



- 🟩 Remaining Level of Effort
- ▬ % Complete
- 🟦 Actual Level of Effort
- 🟦 Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

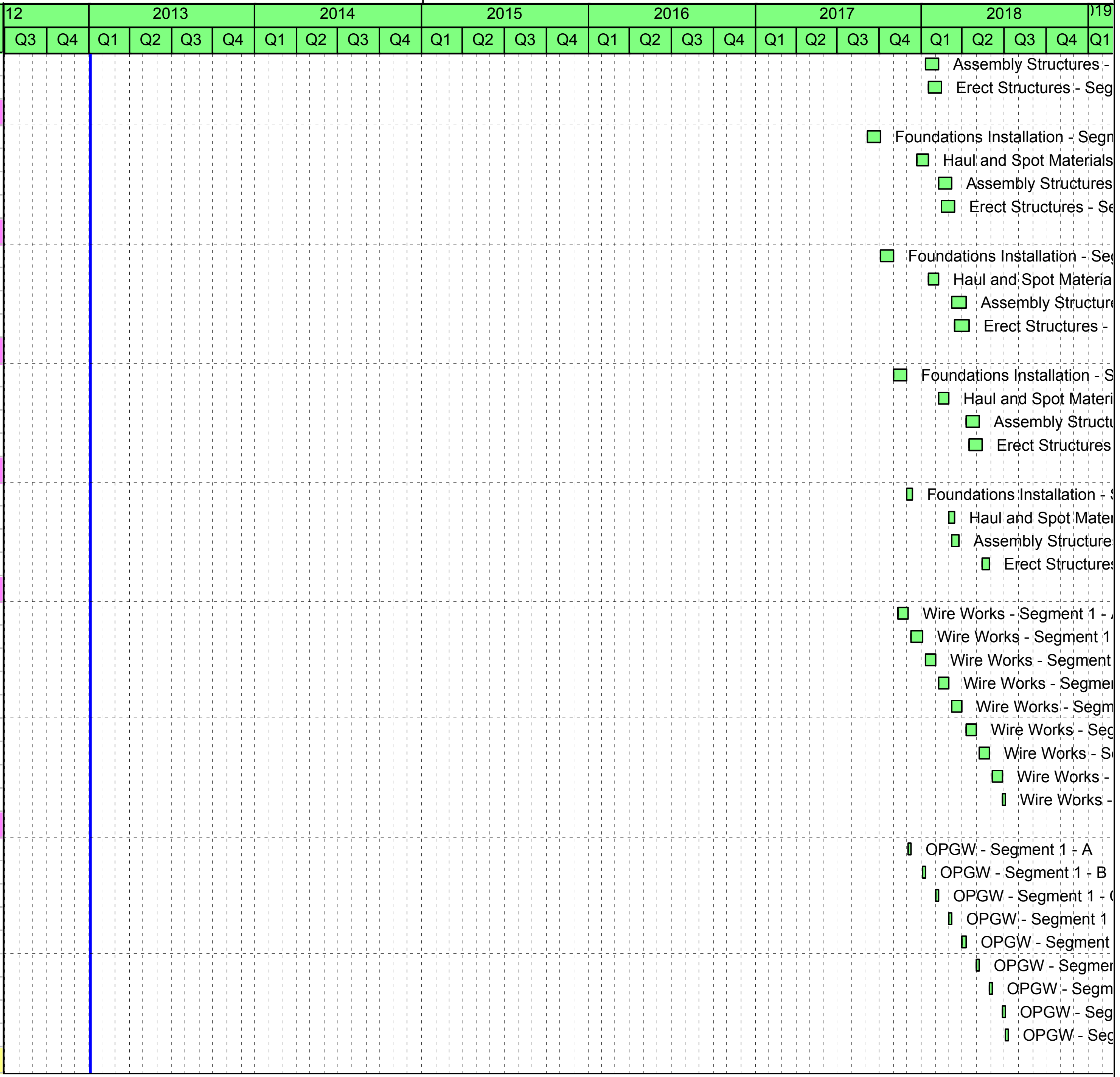
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S1-E-003	Assembly Structures - Segment 1 - E	20d	10-Jan-18	07-Feb-18
S1-E-004	Erect Structures - Segment 1 - E	20d	17-Jan-18	14-Feb-18
Section F		132d	05-Sep-17	15-Mar-18
S1-F-001	Foundations Installation - Segment 1 - F	20d	05-Sep-17	02-Oct-17
S1-F-002	Haul and Spot Materials - Segment 1 - F	15d	22-Dec-17	17-Jan-18
S1-F-003	Assembly Structures - Segment 1 - F	20d	07-Feb-18	08-Mar-18
S1-F-004	Erect Structures - Segment 1 - F	20d	14-Feb-18	15-Mar-18
Section G		132d	03-Oct-17	16-Apr-18
S1-G-001	Foundations Installation - Segment 1 - G	20d	03-Oct-17	31-Oct-17
S1-G-002	Haul and Spot Materials - Segment 1 - G	15d	17-Jan-18	07-Feb-18
S1-G-003	Assembly Structures - Segment 1 - G	20d	08-Mar-18	09-Apr-18
S1-G-004	Erect Structures - Segment 1 - G	20d	15-Mar-18	16-Apr-18
Section H		132d	01-Nov-17	14-May-18
S1-H-001	Foundations Installation - Segment 1 - H	20d	01-Nov-17	29-Nov-17
S1-H-002	Haul and Spot Materials - Segment 1 - H	15d	07-Feb-18	01-Mar-18
S1-H-003	Assembly Structures - Segment 1 - H	20d	09-Apr-18	07-May-18
S1-H-004	Erect Structures - Segment 1 - H	20d	16-Apr-18	14-May-18
Section I		122d	30-Nov-17	29-May-18
S1-I-001	Foundations Installation - Segment 1 - I	10d	30-Nov-17	13-Dec-17
S1-I-002	Haul and Spot Materials - Segment 1 - I	8d	01-Mar-18	13-Mar-18
S1-I-003	Assembly Structures - Segment 1 - I	10d	08-Mar-18	22-Mar-18
S1-I-004	Erect Structures - Segment 1- I	10d	14-May-18	29-May-18
Wire Runs		160d	09-Nov-17	04-Jul-18
S1-CN-1000	Wire Works - Segment 1 - A	15d	09-Nov-17	01-Dec-17
S1-CN-1010	Wire Works - Segment 1 - B	15d	08-Dec-17	03-Jan-18
S1-CN-1020	Wire Works - Segment 1 - C	15d	10-Jan-18	31-Jan-18
S1-CN-1030	Wire Works - Segment 1 - D	15d	07-Feb-18	01-Mar-18
S1-CN-1040	Wire Works - Segment 1 - E	15d	08-Mar-18	29-Mar-18
S1-CN-1050	Wire Works - Segment 1 - F	15d	09-Apr-18	30-Apr-18
S1-CN-1060	Wire Works - Segment 1 - G	15d	07-May-18	29-May-18
S1-CN-1070	Wire Works - Segment 1 - H	15d	05-Jun-18	26-Jun-18
S1-CN-1080	Wire Works - Segment 1 - I	5d	26-Jun-18	04-Jul-18
Communications		153d	01-Dec-17	16-Jul-18
S1-CM-1000	OPGW - Segment 1 - A	5d	01-Dec-17	08-Dec-17
S1-CM-1010	OPGW - Segment 1 - B	5d	03-Jan-18	10-Jan-18
S1-CM-1020	OPGW - Segment 1 - C	5d	31-Jan-18	07-Feb-18
S1-CM-1030	OPGW - Segment 1 - D	5d	01-Mar-18	08-Mar-18
S1-CM-1040	OPGW - Segment 1 - E	5d	29-Mar-18	09-Apr-18
S1-CM-1050	OPGW - Segment 1 - F	5d	30-Apr-18	07-May-18
S1-CM-1060	OPGW - Segment 1 - G	5d	29-May-18	05-Jun-18
S1-CM-1070	OPGW - Segment 1 - H	5d	26-Jun-18	04-Jul-18
S1-CM-1080	OPGW - Segment 1 - I	3d	04-Jul-18	09-Jul-18
Splices		148d	08-Dec-17	16-Jul-18



🟩 Remaining Level of Effort
▬ % Complete
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

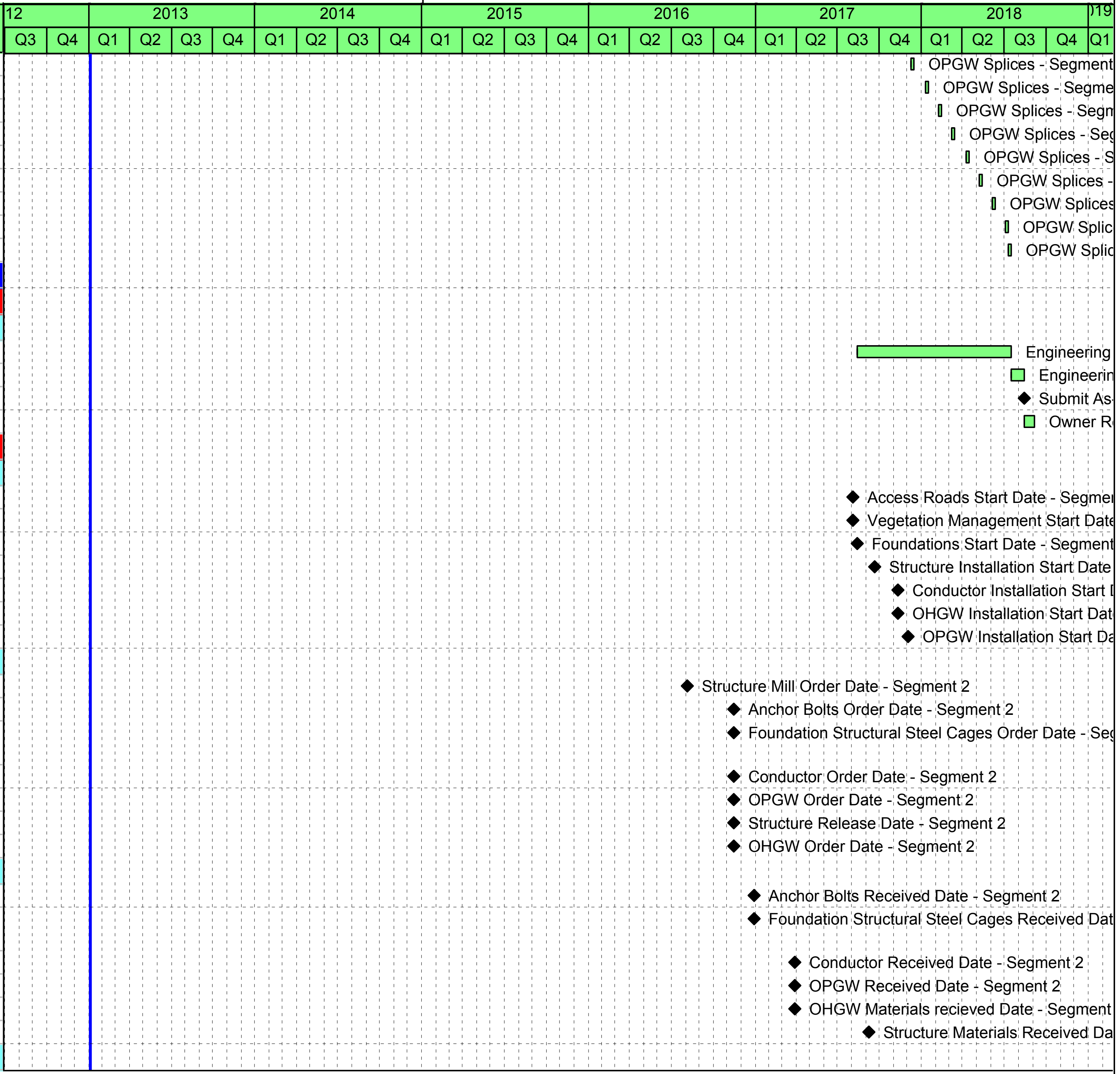
Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

Activity ID	Activity Name	Original Duration	Start	Finish
S1-CMS-1000	OPGW Splices - Segment 1 - A	5d	08-Dec-17	15-Dec-17
S1-CMS-1010	OPGW Splices - Segment 1 - B	5d	10-Jan-18	17-Jan-18
S1-CMS-1020	OPGW Splices - Segment 1 - C	5d	07-Feb-18	14-Feb-18
S1-CMS-1030	OPGW Splices - Segment 1 - D	5d	08-Mar-18	15-Mar-18
S1-CMS-1040	OPGW Splices - Segment 1 - E	5d	09-Apr-18	16-Apr-18
S1-CMS-1050	OPGW Splices - Segment 1 - F	5d	07-May-18	14-May-18
S1-CMS-1060	OPGW Splices - Segment 1 - G	5d	05-Jun-18	12-Jun-18
S1-CMS-1070	OPGW Splices - Segment 1 - H	5d	04-Jul-18	11-Jul-18
S1-CMS-1080	OPGW Splices - Segment 1 - I	3d	11-Jul-18	16-Jul-18
Segment 2 Nipigon River - Terrace Bay (86 km)		520d	04-Aug-16	06-Sep-18
Project Management		265d	14-Aug-17	06-Sep-18
Project Support		265d	14-Aug-17	06-Sep-18
S2-ENG-9000	Engineering Construction Support - Segment 2	230d	14-Aug-17	17-Jul-18
S2-ENG-9010	Engineering As-Builts - Segment 2	20d	17-Jul-18	15-Aug-18
S2-ENG-9020	Submit As-Builts - Segment 2	0d		15-Aug-18
S2-ENG-9030	Owner Review As-Builts - Segment 2	15d	15-Aug-18	06-Sep-18
Contractor Milestones Segment 2		485d	04-Aug-16	17-Jul-18
Start Dates		82d	04-Aug-17	01-Dec-17
S2-SD-MS-1010	Access Roads Start Date - Segment 2	0d	04-Aug-17	
S2-SD-MS-1020	Vegetation Management Start Date - Segment 2	0d	04-Aug-17	
S2-SD-MS-1030	Foundations Start Date - Segment 2	0d	14-Aug-17	
S2-SD-MS-1040	Structure Installation Start Date - Segment 2	0d	20-Sep-17	
S2-SD-MS-1050	Conductor Installation Start Date - Segment 2	0d	09-Nov-17	
S2-SD-MS-1060	OHGW Installation Start Date - Segment 2	0d	09-Nov-17	
S2-SD-MS-1070	OPGW Installation Start Date - Segment 2	0d	01-Dec-17	
Order Dates		71d	04-Aug-16	16-Nov-16
S2-OD-MS-1010	Structure Mill Order Date - Segment 2	0d	04-Aug-16	
S2-OD-MS-1020	Anchor Bolts Order Date - Segment 2	0d	16-Nov-16	
S2-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 2	0d	16-Nov-16	
S2-OD-MS-1040	Conductor Order Date - Segment 2	0d	16-Nov-16	
S2-OD-MS-1050	OPGW Order Date - Segment 2	0d	16-Nov-16	
S2-OD-MS-1060	Structure Release Date - Segment 2	0d	16-Nov-16	
S2-OD-MS-1070	OHGW Order Date - Segment 2	0d	16-Nov-16	
Received Dates		170d	30-Dec-16	06-Sep-17
S2-RD-MS-1010	Anchor Bolts Received Date - Segment 2	0d		30-Dec-16
S2-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segment 2	0d		30-Dec-16
S2-RD-MS-1050	Conductor Received Date - Segment 2	0d		28-Mar-17
S2-RD-MS-1040	OPGW Received Date - Segment 2	0d		28-Mar-17
S2-RD-MS-1030	OHGW Materials recieved Date - Segment 2	0d		28-Mar-17
S2-RD-MS-1060	Structure Materials Received Date - Segment 2	0d		06-Sep-17
Completion Dates		150d	08-Dec-17	17-Jul-18



🟩	Remaining Level of Effort
▬	% Complete
🟦	Actual Level of Effort
🟦	Actual Work
🟩	Remaining Work
🟥	Critical Remaining Work
◆ ◆	Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

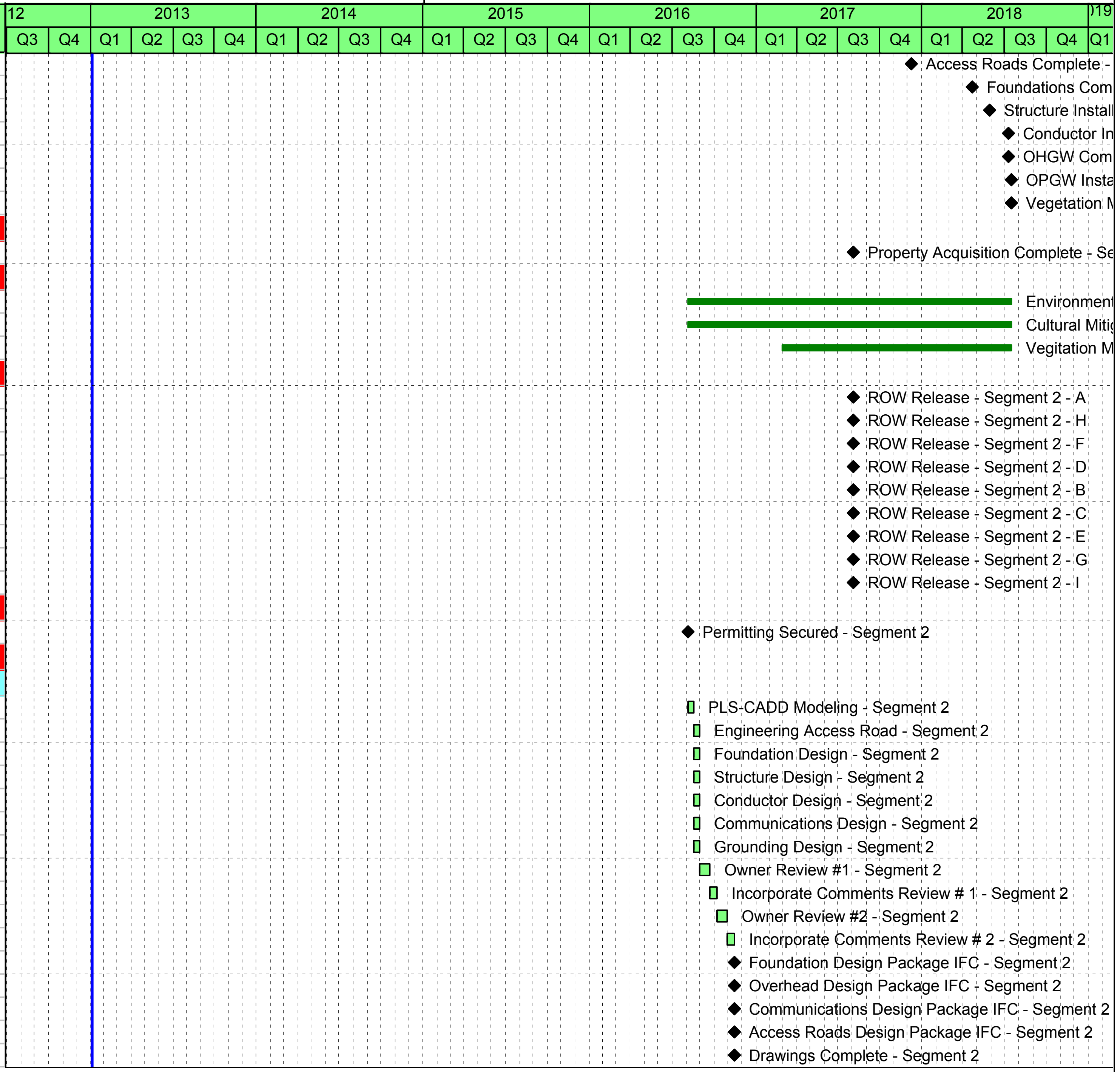
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S2-CD-MS-1010	Access Roads Complete - Segment 2	0d		08-Dec-17
S2-CD-MS-1020	Foundations Complete - Segment 2	0d		20-Apr-18
S2-CD-MS-1030	Structure Installation Complete - Segment 2	0d		29-May-18
S2-CD-MS-1040	Conductor Installation Complete - Segment 2	0d		09-Jul-18
S2-CD-MS-1050	OHGW Complete - Segment 2	0d		09-Jul-18
S2-CD-MS-1060	OPGW Installation Complete - Segment 2	0d		17-Jul-18
S2-CD-MS-1070	Vegetation Management Complete - Segment 2	0d		17-Jul-18
Property		0d	04-Aug-17	04-Aug-17
S2-PRP-1000	Property Acquisition Complete - Segment 2	0d		04-Aug-17
Environmental		485d	04-Aug-16	17-Jul-18
S2-ENV-1000	Environmental Monitoring- Segment 2	485d	04-Aug-16	17-Jul-18
S2-ENV-1010	Cultural Mitigation - Segment 2	485d	04-Aug-16	17-Jul-18
S2-ENV-1020	Vegitation Management - Segment 2	346d	27-Feb-17	17-Jul-18
Right of Way		0d	04-Aug-17	04-Aug-17
S2-ROW-1000	ROW Release - Segment 2 - A	0d	04-Aug-17	
S2-ROW-1010	ROW Release - Segment 2 - H	0d	04-Aug-17	
S2-ROW-1020	ROW Release - Segment 2 - F	0d	04-Aug-17	
S2-ROW-1030	ROW Release - Segment 2 - D	0d	04-Aug-17	
S2-ROW-1040	ROW Release - Segment 2 - B	0d	04-Aug-17	
S2-ROW-1050	ROW Release - Segment 2 - C	0d	04-Aug-17	
S2-ROW-1060	ROW Release - Segment 2 - E	0d	04-Aug-17	
S2-ROW-1070	ROW Release - Segment 2 - G	0d	04-Aug-17	
S2-ROW-1080	ROW Release - Segment 2 - I	0d	04-Aug-17	
Permitting		0d	04-Aug-16	04-Aug-16
S2-PMT-1000	Permitting Secured - Segment 2	0d		04-Aug-16
Transmission Lines		485d	04-Aug-16	17-Jul-18
Engineering-T-Line		71d	04-Aug-16	16-Nov-16
S2-ENG-1000	PLS-CADD Modeling - Segment 2	10d	04-Aug-16	18-Aug-16
S2-ENG-1010	Engineering Access Road - Segment 2	10d	18-Aug-16	01-Sep-16
S2-ENG-1020	Foundation Design - Segment 2	10d	18-Aug-16	01-Sep-16
S2-ENG-1030	Structure Design - Segment 2	10d	18-Aug-16	01-Sep-16
S2-ENG-1040	Conductor Design - Segment 2	10d	18-Aug-16	01-Sep-16
S2-ENG-1050	Communications Design - Segment 2	10d	18-Aug-16	01-Sep-16
S2-ENG-1060	Grounding Design - Segment 2	10d	18-Aug-16	01-Sep-16
S2-ENG-1070	Owner Review #1 - Segment 2	15d	01-Sep-16	23-Sep-16
S2-ENG-1080	Incorporate Comments Review # 1 - Segment 2	10d	23-Sep-16	07-Oct-16
S2-ENG-1090	Owner Review #2 - Segment 2	15d	07-Oct-16	31-Oct-16
S2-ENG-1100	Incorporate Comments Review # 2 - Segment 2	10d	31-Oct-16	15-Nov-16
S2-ENG-1120	Foundation Design Package IFC - Segment 2	0d		15-Nov-16
S2-ENG-1130	Overhead Design Package IFC - Segment 2	0d		15-Nov-16
S2-ENG-1140	Communications Design Package IFC - Segment 2	0d		15-Nov-16
S2-ENG-1150	Access Roads Design Package IFC - Segment 2	0d		15-Nov-16
S2-ENG-1160	Drawings Complete - Segment 2	0d		16-Nov-16



- 🟩 Remaining Level of Effort
- ▬ % Complete
- 🟦 Actual Level of Effort
- 🟦 Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN
TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

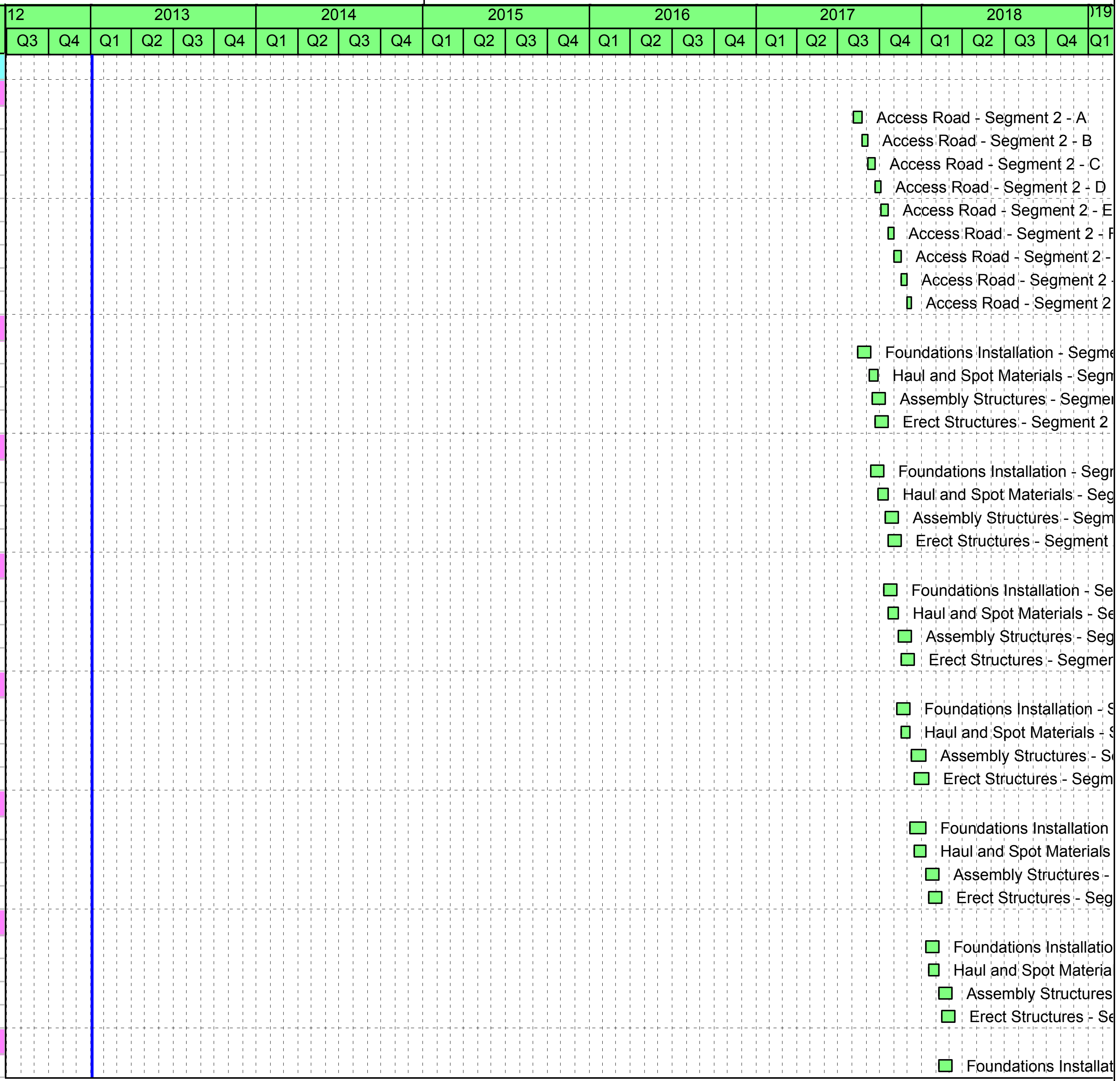
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
Construction-T-Line		236d	04-Aug-17	17-Jul-18
Access Roads		86d	04-Aug-17	08-Dec-17
S2-AR-1000	Access Road - Segment 2 - A	10d	04-Aug-17	21-Aug-17
S2-AR-1010	Access Road - Segment 2 - B	10d	21-Aug-17	05-Sep-17
S2-AR-1020	Access Road - Segment 2 - C	10d	05-Sep-17	19-Sep-17
S2-AR-1030	Access Road - Segment 2 - D	10d	19-Sep-17	03-Oct-17
S2-AR-1040	Access Road - Segment 2 - E	10d	03-Oct-17	18-Oct-17
S2-AR-1050	Access Road - Segment 2 - F	10d	18-Oct-17	01-Nov-17
S2-AR-1060	Access Road - Segment 2 - G	10d	01-Nov-17	16-Nov-17
S2-AR-1070	Access Road - Segment 2 - H	10d	16-Nov-17	30-Nov-17
S2-AR-1080	Access Road - Segment 2 - I	6d	30-Nov-17	08-Dec-17
Section A		47d	14-Aug-17	19-Oct-17
S2-A-001	Foundations Installation - Segment 2 - A	20d	14-Aug-17	12-Sep-17
S2-A-002	Haul and Spot Materials - Segment 2 - A	15d	06-Sep-17	27-Sep-17
S2-A-003	Assembly Structures - Segment 2 - A	20d	13-Sep-17	11-Oct-17
S2-A-004	Erect Structures - Segment 2 - A	20d	20-Sep-17	19-Oct-17
Section B		47d	12-Sep-17	17-Nov-17
S2-B-001	Foundations Installation - Segment 2 - B	20d	12-Sep-17	10-Oct-17
S2-B-002	Haul and Spot Materials - Segment 2 - B	15d	27-Sep-17	19-Oct-17
S2-B-003	Assembly Structures - Segment 2 - B	20d	11-Oct-17	09-Nov-17
S2-B-004	Erect Structures - Segment 2 - B	20d	19-Oct-17	17-Nov-17
Section C		47d	10-Oct-17	15-Dec-17
S2-C-001	Foundations Installation - Segment 2 - C	20d	10-Oct-17	08-Nov-17
S2-C-002	Haul and Spot Materials - Segment 2 - C	15d	19-Oct-17	09-Nov-17
S2-C-003	Assembly Structures - Segment 2 - C	20d	09-Nov-17	08-Dec-17
S2-C-004	Erect Structures - Segment 2 - C	20d	17-Nov-17	15-Dec-17
Section D		47d	08-Nov-17	17-Jan-18
S2-D-001	Foundations Installation - Segment 2 - D	20d	08-Nov-17	07-Dec-17
S2-D-002	Haul and Spot Materials - Segment 2 - D	15d	16-Nov-17	07-Dec-17
S2-D-003	Assembly Structures - Segment 2 - D	20d	08-Dec-17	10-Jan-18
S2-D-004	Erect Structures - Segment 2 - D	20d	15-Dec-17	17-Jan-18
Section E		47d	07-Dec-17	14-Feb-18
S2-E-001	Foundations Installation - Segment 2 - E	20d	07-Dec-17	09-Jan-18
S2-E-002	Haul and Spot Materials - Segment 2 - E	15d	14-Dec-17	09-Jan-18
S2-E-003	Assembly Structures - Segment 2 - E	20d	10-Jan-18	07-Feb-18
S2-E-004	Erect Structures - Segment 2 - E	20d	17-Jan-18	14-Feb-18
Section F		47d	09-Jan-18	15-Mar-18
S2-F-001	Foundations Installation - Segment 2 - F	20d	09-Jan-18	06-Feb-18
S2-F-002	Haul and Spot Materials - Segment 2 - F	15d	16-Jan-18	06-Feb-18
S2-F-003	Assembly Structures - Segment 2 - F	20d	07-Feb-18	08-Mar-18
S2-F-004	Erect Structures - Segment 2 - F	20d	14-Feb-18	15-Mar-18
Section G		47d	06-Feb-18	16-Apr-18
S2-G-001	Foundations Installation - Segment 2 - G	20d	06-Feb-18	07-Mar-18



Remaining Level of Effort
% Complete
Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

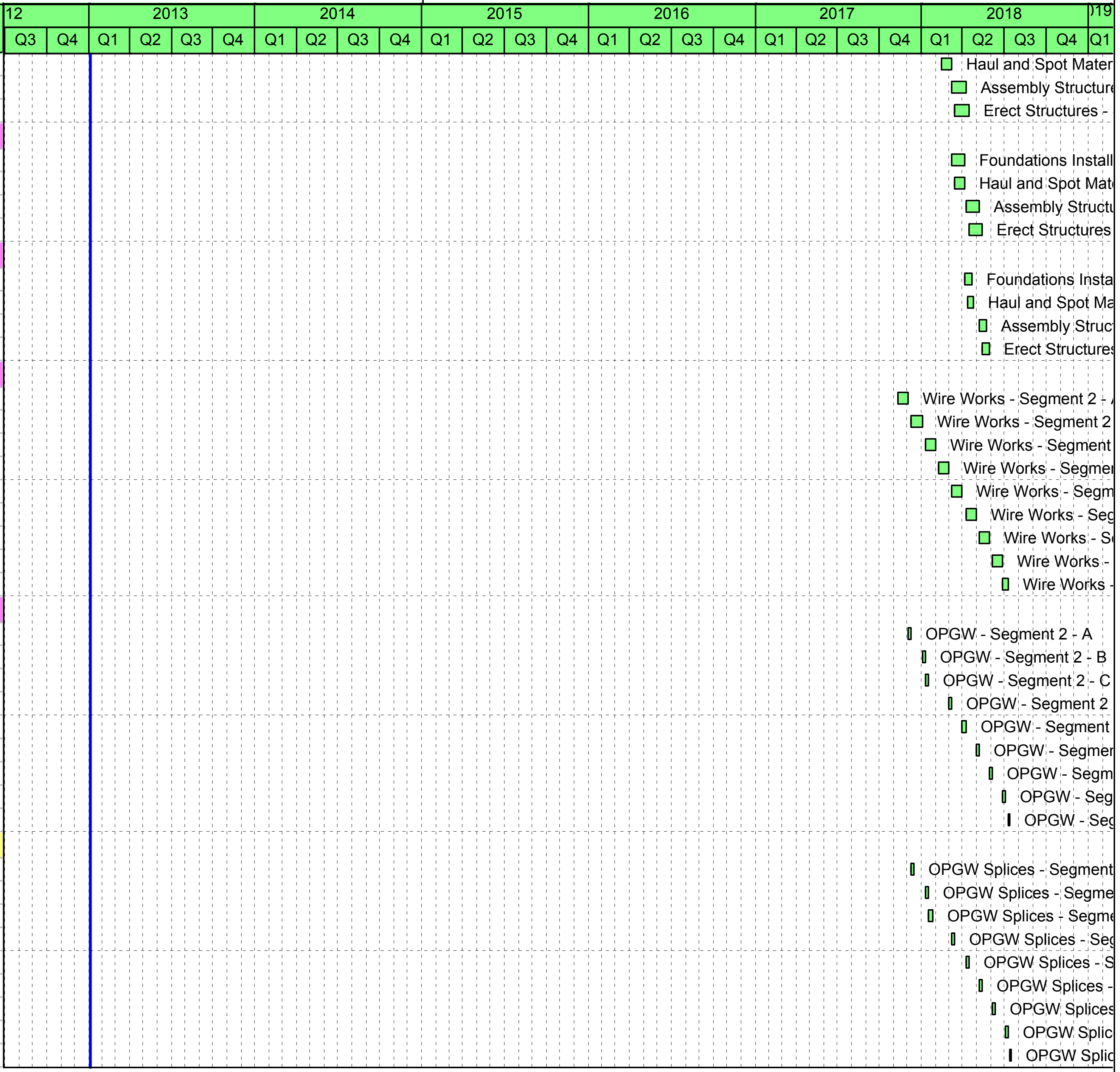
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S2-G-002	Haul and Spot Materials - Segment 2 - G	15d	13-Feb-18	07-Mar-18
S2-G-003	Assembly Structures - Segment 2 - G	20d	08-Mar-18	09-Apr-18
S2-G-004	Erect Structures - Segment 2 - G	20d	15-Mar-18	16-Apr-18
Section H		47d	07-Mar-18	14-May-18
S2-H-001	Foundations Installation - Segment 2 - H	20d	07-Mar-18	06-Apr-18
S2-H-002	Haul and Spot Materials - Segment 2 - H	15d	14-Mar-18	06-Apr-18
S2-H-003	Assembly Structures - Segment 2 - H	20d	09-Apr-18	07-May-18
S2-H-004	Erect Structures - Segment 2 - H	20d	16-Apr-18	14-May-18
Section I		37d	06-Apr-18	29-May-18
S2-I-001	Foundations Installation - Segment 2 - I	10d	06-Apr-18	20-Apr-18
S2-I-002	Haul and Spot Materials - Segment 2 - I	8d	13-Apr-18	25-Apr-18
S2-I-003	Assembly Structures - Segment 2 - I	10d	07-May-18	22-May-18
S2-I-004	Erect Structures - Segment 2 - I	10d	14-May-18	29-May-18
Wire Runs		163d	09-Nov-17	09-Jul-18
S2-CN-1000	Wire Works - Segment 2 - A	15d	09-Nov-17	01-Dec-17
S2-CN-1010	Wire Works - Segment 2 - B	15d	08-Dec-17	03-Jan-18
S2-CN-1020	Wire Works - Segment 2 - C	15d	10-Jan-18	31-Jan-18
S2-CN-1030	Wire Works - Segment 2 - D	15d	07-Feb-18	01-Mar-18
S2-CN-1040	Wire Works - Segment 2 - E	15d	08-Mar-18	29-Mar-18
S2-CN-1050	Wire Works - Segment 2 - F	15d	09-Apr-18	30-Apr-18
S2-CN-1060	Wire Works - Segment 2 - G	15d	07-May-18	29-May-18
S2-CN-1070	Wire Works - Segment 2 - H	15d	05-Jun-18	26-Jun-18
S2-CN-1080	Wire Works - Segment 2 - I	8d	26-Jun-18	09-Jul-18
Communications		154d	01-Dec-17	17-Jul-18
S2-CM-1000	OPGW - Segment 2 - A	5d	01-Dec-17	08-Dec-17
S2-CM-1010	OPGW - Segment 2 - B	5d	03-Jan-18	10-Jan-18
S2-CM-1020	OPGW - Segment 2 - C	5d	10-Jan-18	17-Jan-18
S2-CM-1030	OPGW - Segment 2 - D	5d	01-Mar-18	08-Mar-18
S2-CM-1040	OPGW - Segment 2 - E	5d	29-Mar-18	09-Apr-18
S2-CM-1050	OPGW - Segment 2 - F	5d	30-Apr-18	07-May-18
S2-CM-1060	OPGW - Segment 2 - G	5d	29-May-18	05-Jun-18
S2-CM-1070	OPGW - Segment 2 - H	5d	26-Jun-18	04-Jul-18
S2-CM-1080	OPGW - Segment 2 - I	3d	09-Jul-18	12-Jul-18
Splices		149d	08-Dec-17	17-Jul-18
S2-CMS-1000	OPGW Splices - Segment 2 - A	5d	08-Dec-17	15-Dec-17
S2-CMS-1010	OPGW Splices - Segment 2 - B	5d	10-Jan-18	17-Jan-18
S2-CMS-1020	OPGW Splices - Segment 2 - C	5d	17-Jan-18	24-Jan-18
S2-CMS-1030	OPGW Splices - Segment 2 - D	5d	08-Mar-18	15-Mar-18
S2-CMS-1040	OPGW Splices - Segment 2 - E	5d	09-Apr-18	16-Apr-18
S2-CMS-1050	OPGW Splices - Segment 2 - F	5d	07-May-18	14-May-18
S2-CMS-1060	OPGW Splices - Segment 2 - G	5d	05-Jun-18	12-Jun-18
S2-CMS-1070	OPGW Splices - Segment 2 - H	5d	04-Jul-18	11-Jul-18
S2-CMS-1080	OPGW Splices - Segment 2 - I	3d	12-Jul-18	17-Jul-18



🟩	Remaining Level of Effort
▬	% Complete
🟦	Actual Level of Effort
🟦	Actual Work
🟩	Remaining Work
🟥	Critical Remaining Work
◆ ◆	Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

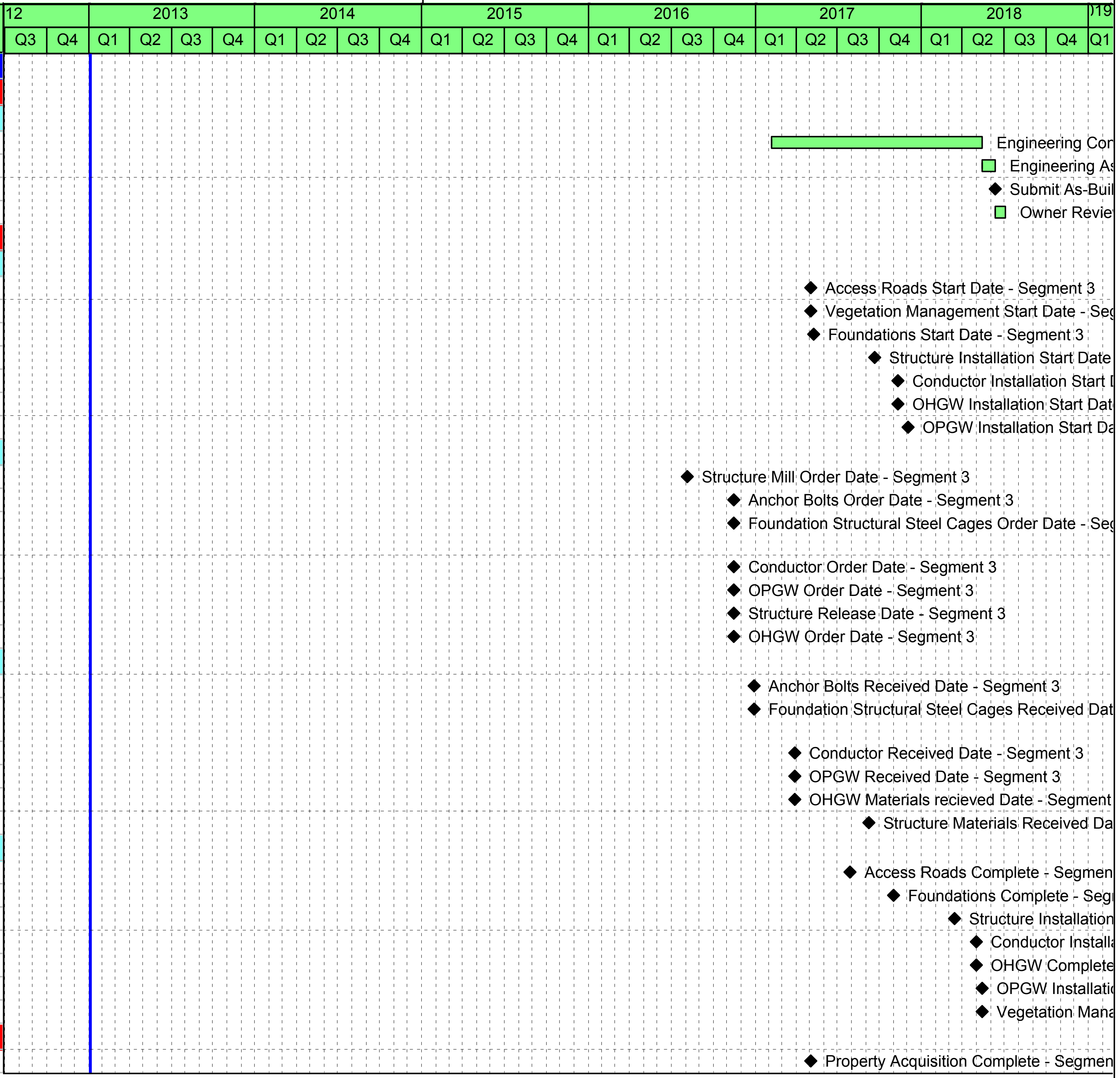
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
Segment 3 Terrace Bay - Marathon (60 km)		476d	04-Aug-16	04-Jul-18
Project Management		350d	06-Feb-17	04-Jul-18
Project Support		350d	06-Feb-17	04-Jul-18
S3-ENG-9000	Engineering Construction Support - Segment 3	315d	06-Feb-17	14-May-18
S3-ENG-9010	Engineering As-Builts - Segment 3	20d	14-May-18	12-Jun-18
S3-ENG-9020	Submit As-Builts - Segment 3	0d		12-Jun-18
S3-ENG-9030	Owner Review As-Builts - Segment 3	15d	12-Jun-18	04-Jul-18
Contractor Milestones Segment 3		441d	04-Aug-16	14-May-18
Start Dates		147d	03-May-17	01-Dec-17
S3-SD-MS-1010	Access Roads Start Date - Segment 3	0d	03-May-17	
S3-SD-MS-1020	Vegetation Management Start Date - Segment 3	0d	03-May-17	
S3-SD-MS-1030	Foundations Start Date - Segment 3	0d	10-May-17	
S3-SD-MS-1040	Structure Installation Start Date - Segment 3	0d	20-Sep-17	
S3-SD-MS-1050	Conductor Installation Start Date - Segment 3	0d	09-Nov-17	
S3-SD-MS-1060	OHGW Installation Start Date - Segment 3	0d	09-Nov-17	
S3-SD-MS-1070	OPGW Installation Start Date - Segment 3	0d	01-Dec-17	
Order Dates		71d	04-Aug-16	16-Nov-16
S3-OD-MS-1010	Structure Mill Order Date - Segment 3	0d	04-Aug-16	
S3-OD-MS-1020	Anchor Bolts Order Date - Segment 3	0d	16-Nov-16	
S3-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 3	0d	16-Nov-16	
S3-OD-MS-1040	Conductor Order Date - Segment 3	0d	16-Nov-16	
S3-OD-MS-1050	OPGW Order Date - Segment 3	0d	16-Nov-16	
S3-OD-MS-1060	Structure Release Date - Segment 3	0d	16-Nov-16	
S3-OD-MS-1070	OHGW Order Date - Segment 3	0d	16-Nov-16	
Received Dates		170d	30-Dec-16	06-Sep-17
S3-RD-MS-1010	Anchor Bolts Received Date - Segment 3	0d		30-Dec-16
S3-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segment 3	0d		30-Dec-16
S3-RD-MS-1050	Conductor Received Date - Segment 3	0d		28-Mar-17
S3-RD-MS-1040	OPGW Received Date - Segment 3	0d		28-Mar-17
S3-RD-MS-1030	OHGW Materials recieved Date - Segment 3	0d		28-Mar-17
S3-RD-MS-1060	Structure Materials Received Date - Segment 3	0d		06-Sep-17
Completion Dates		197d	28-Jul-17	14-May-18
S3-CD-MS-1010	Access Roads Complete - Segment 3	0d		28-Jul-17
S3-CD-MS-1020	Foundations Complete - Segment 3	0d		01-Nov-17
S3-CD-MS-1030	Structure Installation Complete - Segment 3	0d		15-Mar-18
S3-CD-MS-1040	Conductor Installation Complete - Segment 3	0d		30-Apr-18
S3-CD-MS-1060	OHGW Complete - Segment 3	0d		30-Apr-18
S3-CD-MS-1080	OPGW Installation Complete - Segment 3	0d		14-May-18
S3-CD-MS-1070	Vegetation Management Complete - Segment 3	0d		14-May-18
Property		0d	03-May-17	03-May-17
A62990	Property Acquisition Complete - Segment 3	0d		03-May-17



🟩 Remaining Level of Effort ▬ % Complete
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

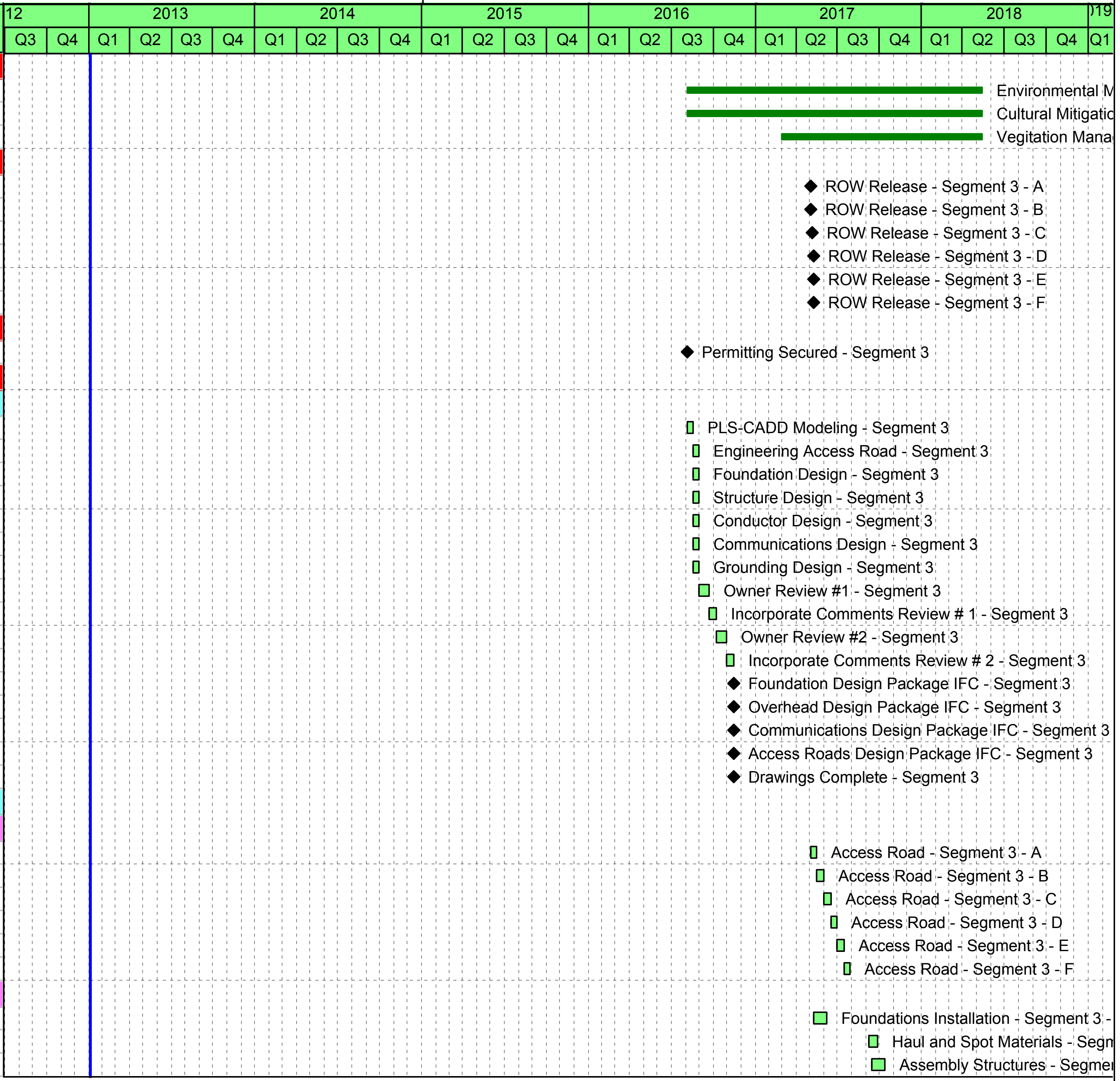
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
Environmental		441d	04-Aug-16	14-May-18
S3-ENV-1000	Environmental Monitoring- Segment 3	441d	04-Aug-16	14-May-18
S3-ENV-1010	Cultural Mitigation - Segment 3	441d	04-Aug-16	14-May-18
S3-ENV-1020	Vegitation Management - Segment 3	302d	27-Feb-17	14-May-18
Right of Way		5d	03-May-17	10-May-17
S3-ROW-1000	ROW Release - Segment 3 - A	0d	03-May-17	
S3-ROW-1010	ROW Release - Segment 3 - B	0d	04-May-17	
S3-ROW-1020	ROW Release - Segment 3 - C	0d	05-May-17	
S3-ROW-1030	ROW Release - Segment 3 - D	0d	08-May-17	
S3-ROW-1040	ROW Release - Segment 3 - E	0d	09-May-17	
S3-ROW-1050	ROW Release - Segment 3 - F	0d	10-May-17	
Permitting		0d	04-Aug-16	04-Aug-16
S3-PMT-1000	Permitting Secured - Segment 3	0d		04-Aug-16
Transmission Lines		441d	04-Aug-16	14-May-18
Engineering-T-Line		71d	04-Aug-16	16-Nov-16
S3-ENG-1000	PLS-CADD Modeling - Segment 3	10d	04-Aug-16	18-Aug-16
S3-ENG-1010	Engineering Access Road - Segment 3	10d	18-Aug-16	01-Sep-16
S3-ENG-1020	Foundation Design - Segment 3	10d	18-Aug-16	01-Sep-16
S3-ENG-1030	Structure Design - Segment 3	10d	18-Aug-16	01-Sep-16
S3-ENG-1040	Conductor Design - Segment 3	10d	18-Aug-16	01-Sep-16
S3-ENG-1050	Communications Design - Segment 3	10d	18-Aug-16	01-Sep-16
S3-ENG-1060	Grounding Design - Segment 3	10d	18-Aug-16	01-Sep-16
S3-ENG-1070	Owner Review #1 - Segment 3	15d	01-Sep-16	23-Sep-16
S3-ENG-1080	Incorporate Comments Review # 1 - Segment 3	10d	23-Sep-16	07-Oct-16
S3-ENG-1090	Owner Review #2 - Segment 3	15d	07-Oct-16	31-Oct-16
S3-ENG-1100	Incorporate Comments Review # 2 - Segment 3	10d	31-Oct-16	15-Nov-16
S3-ENG-1120	Foundation Design Package IFC - Segment 3	0d		15-Nov-16
S3-ENG-1130	Overhead Design Package IFC - Segment 3	0d		15-Nov-16
S3-ENG-1140	Communications Design Package IFC - Segment 3	0d		15-Nov-16
S3-ENG-1150	Access Roads Design Package IFC - Segment 3	0d		15-Nov-16
S3-ENG-1160	Drawings Complete - Segment 3	0d		16-Nov-16
Construction-T-Line		257d	03-May-17	14-May-18
Access Roads		60d	03-May-17	28-Jul-17
S3-AR-1000	Access Road - Segment 3 - A	10d	03-May-17	17-May-17
S3-AR-1010	Access Road - Segment 3 - B	10d	17-May-17	01-Jun-17
S3-AR-1020	Access Road - Segment 3 - C	10d	01-Jun-17	15-Jun-17
S3-AR-1030	Access Road - Segment 3 - D	10d	15-Jun-17	29-Jun-17
S3-AR-1040	Access Road - Segment 3 - E	10d	29-Jun-17	14-Jul-17
S3-AR-1050	Access Road - Segment 3 - F	10d	14-Jul-17	28-Jul-17
Section A		112d	10-May-17	19-Oct-17
S3-A-001	Foundations Installation - Segment 3 - A	20d	10-May-17	08-Jun-17
S3-A-002	Haul and Spot Materials - Segment 3 - A	15d	06-Sep-17	27-Sep-17
S3-A-003	Assembly Structures - Segment 3 - A	20d	13-Sep-17	11-Oct-17



Remaining Level of Effort
% Complete
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
◆ ◆ Milestone

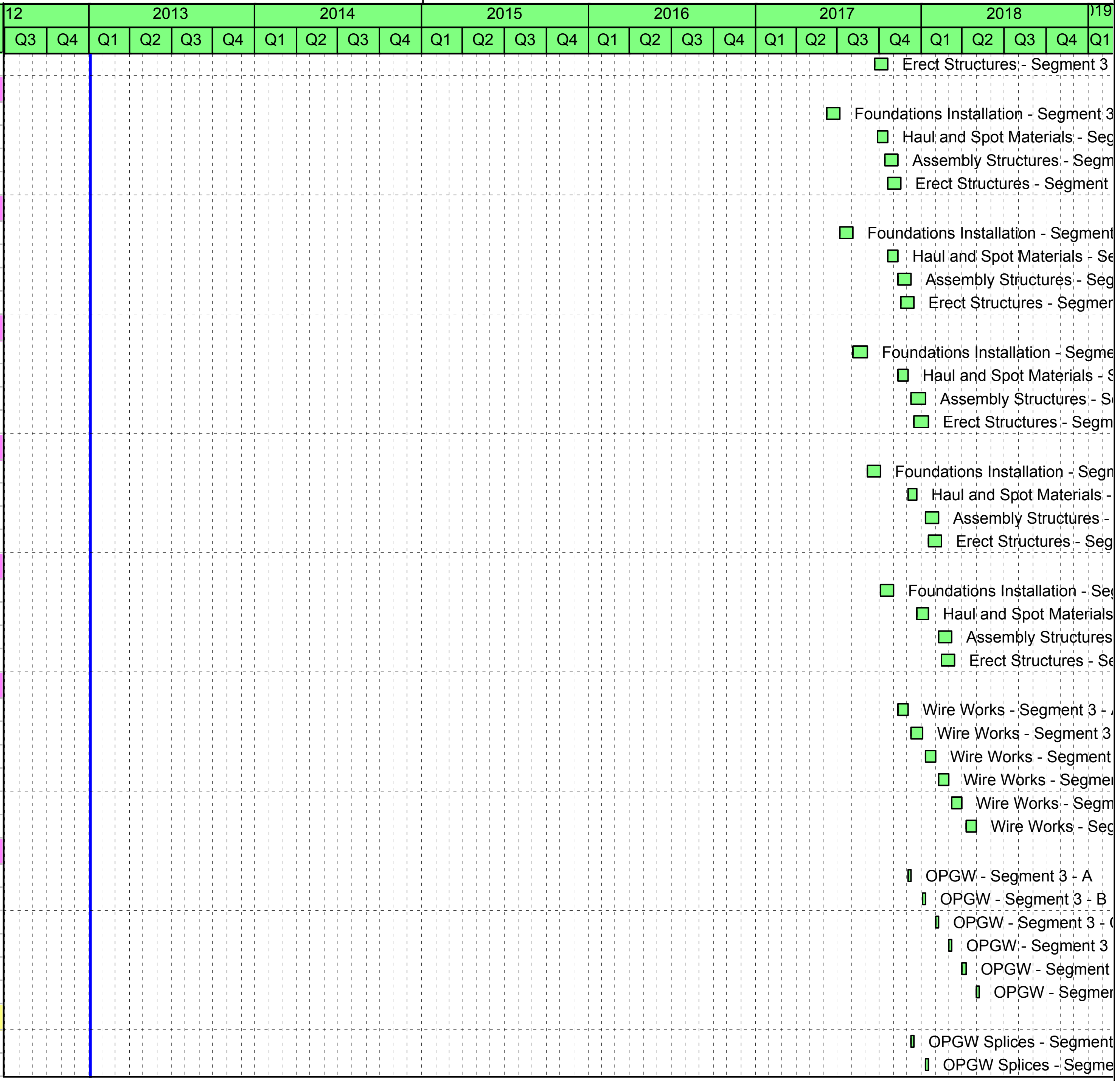
Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

Activity ID	Activity Name	Original Duration	Start	Finish
S3-A-004	Erect Structures - Segment 3 - A	20d	20-Sep-17	19-Oct-17
Section B		112d	08-Jun-17	17-Nov-17
S3-B-001	Foundations Installation - Segment 3 - B	20d	08-Jun-17	07-Jul-17
S3-B-002	Haul and Spot Materials - Segment 3 - B	15d	27-Sep-17	19-Oct-17
S3-B-003	Assembly Structures - Segment 3 - B	20d	11-Oct-17	09-Nov-17
S3-B-004	Erect Structures - Segment 3 - B	20d	19-Oct-17	17-Nov-17
Section C		112d	07-Jul-17	15-Dec-17
S3-C-001	Foundations Installation - Segment 3 - C	20d	07-Jul-17	04-Aug-17
S3-C-002	Haul and Spot Materials - Segment 3 - C	15d	19-Oct-17	09-Nov-17
S3-C-003	Assembly Structures - Segment 3 - C	20d	09-Nov-17	08-Dec-17
S3-C-004	Erect Structures - Segment 3 - C	20d	17-Nov-17	15-Dec-17
Section D		112d	04-Aug-17	17-Jan-18
S3-D-001	Foundations Installation - Segment 3 - D	20d	04-Aug-17	05-Sep-17
S3-D-002	Haul and Spot Materials - Segment 3 - D	15d	09-Nov-17	01-Dec-17
S3-D-003	Assembly Structures - Segment 3 - D	20d	08-Dec-17	10-Jan-18
S3-D-004	Erect Structures - Segment 3 - D	20d	15-Dec-17	17-Jan-18
Section E		112d	05-Sep-17	14-Feb-18
S3-E-001	Foundations Installation - Segment 3 - E	20d	05-Sep-17	03-Oct-17
S3-E-002	Haul and Spot Materials - Segment 3 - E	15d	01-Dec-17	22-Dec-17
S3-E-003	Assembly Structures - Segment 3 - E	20d	10-Jan-18	07-Feb-18
S3-E-004	Erect Structures - Segment 3 - E	20d	17-Jan-18	14-Feb-18
Section F		112d	03-Oct-17	15-Mar-18
S3-F-001	Foundations Installation - Segment 3 - F	20d	03-Oct-17	01-Nov-17
S3-F-002	Haul and Spot Materials - Segment 3 - F	15d	22-Dec-17	17-Jan-18
S3-F-003	Assembly Structures - Segment 3 - F	20d	07-Feb-18	08-Mar-18
S3-F-004	Erect Structures - Segment 3 - F	20d	14-Feb-18	15-Mar-18
Wire Runs		115d	09-Nov-17	30-Apr-18
S3-CN-1000	Wire Works - Segment 3 - A	15d	09-Nov-17	01-Dec-17
S3-CN-1010	Wire Works - Segment 3 - B	15d	08-Dec-17	03-Jan-18
S3-CN-1020	Wire Works - Segment 3 - C	15d	10-Jan-18	31-Jan-18
S3-CN-1030	Wire Works - Segment 3 - D	15d	07-Feb-18	01-Mar-18
S3-CN-1040	Wire Works - Segment 3 - E	15d	08-Mar-18	29-Mar-18
S3-CN-1050	Wire Works - Segment 3 - F	15d	09-Apr-18	30-Apr-18
Communications		110d	01-Dec-17	14-May-18
S3-CM-1000	OPGW - Segment 3 - A	5d	01-Dec-17	08-Dec-17
S3-CM-1010	OPGW - Segment 3 - B	5d	03-Jan-18	10-Jan-18
S3-CM-1020	OPGW - Segment 3 - C	5d	31-Jan-18	07-Feb-18
S3-CM-1030	OPGW - Segment 3 - D	5d	01-Mar-18	08-Mar-18
S3-CM-1040	OPGW - Segment 3 - E	5d	29-Mar-18	09-Apr-18
S3-CM-1050	OPGW - Segment 3 - F	5d	30-Apr-18	07-May-18
Splices		105d	08-Dec-17	14-May-18
S3-CMS-1000	OPGW Splices - Segment 3 - A	5d	08-Dec-17	15-Dec-17
S3-CMS-1010	OPGW Splices - Segment 3 - B	5d	10-Jan-18	17-Jan-18



🟩 Remaining Level of Effort
▬ % Complete
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

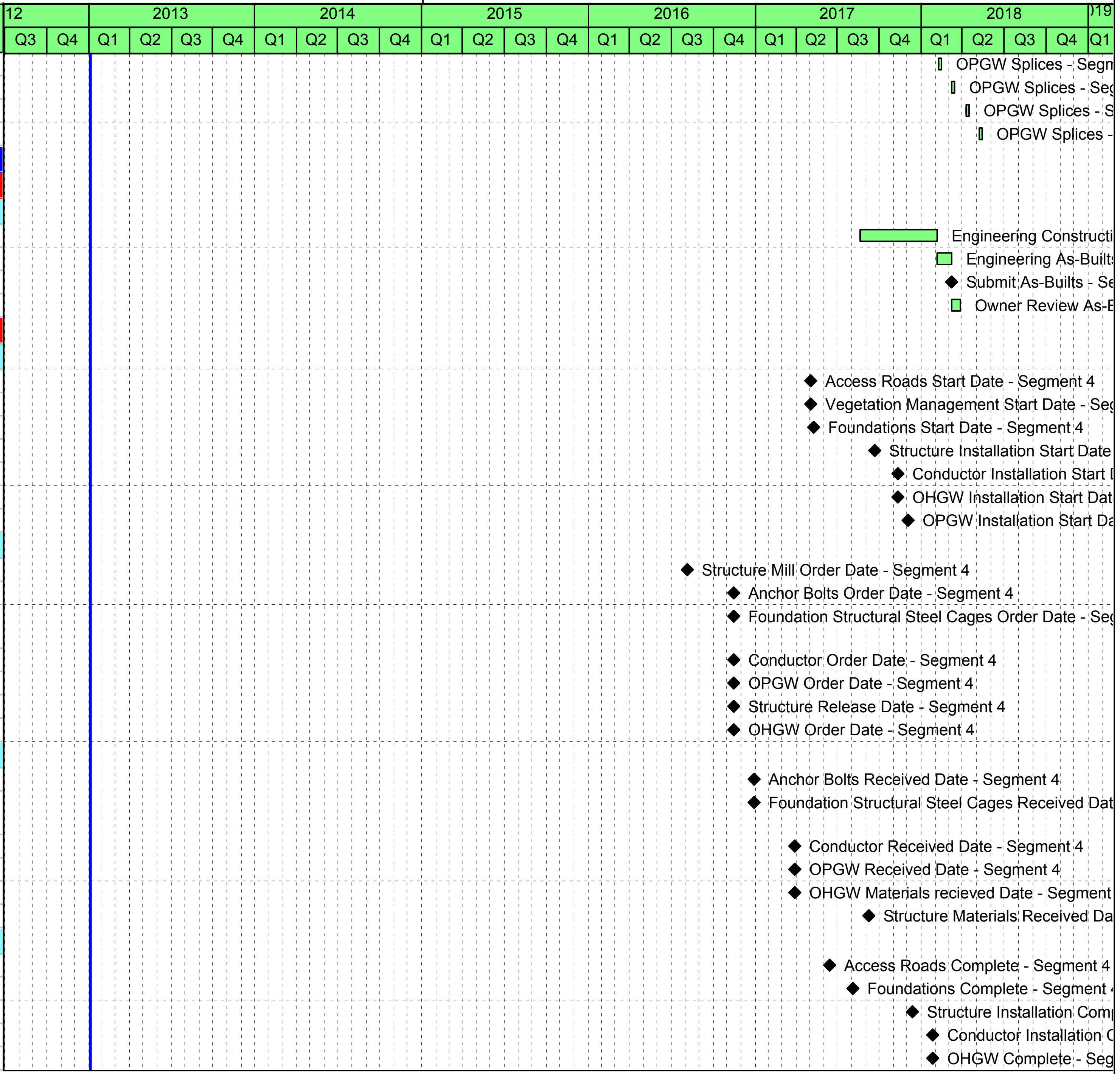
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S3-CMS-1020	OPGW Splices - Segment 3 - C	5d	07-Feb-18	14-Feb-18
S3-CMS-1030	OPGW Splices - Segment 3 - D	5d	08-Mar-18	15-Mar-18
S3-CMS-1040	OPGW Splices - Segment 3 - E	5d	09-Apr-18	16-Apr-18
S3-CMS-1050	OPGW Splices - Segment 3 - F	5d	07-May-18	14-May-18
Segment 4 Marathon - White River (28 km)		409d	04-Aug-16	27-Mar-18
Project Management		150d	18-Aug-17	27-Mar-18
Project Support		150d	18-Aug-17	27-Mar-18
S4-ENG-9000	Engineering Construction Support - Segment 4	115d	18-Aug-17	05-Feb-18
S4-ENG-9010	Engineering As-Builts - Segment 4	20d	05-Feb-18	06-Mar-18
S4-ENG-9020	Submit As-Builts - Segment 4	0d		06-Mar-18
S4-ENG-9030	Owner Review As-Builts - Segment 4	15d	06-Mar-18	27-Mar-18
Contractor Milestones Segment 4		374d	04-Aug-16	05-Feb-18
Start Dates		147d	03-May-17	01-Dec-17
S4-SD-MS-1010	Access Roads Start Date - Segment 4	0d	03-May-17	
S4-SD-MS-1020	Vegetation Management Start Date - Segment 4	0d	03-May-17	
S4-SD-MS-1030	Foundations Start Date - Segment 4	0d	10-May-17	
S4-SD-MS-1040	Structure Installation Start Date - Segment 4	0d	20-Sep-17	
S4-SD-MS-1050	Conductor Installation Start Date - Segment 4	0d	09-Nov-17	
S4-SD-MS-1060	OHGW Installation Start Date - Segment 4	0d	09-Nov-17	
S4-SD-MS-1070	OPGW Installation Start Date - Segment 4	0d	01-Dec-17	
Order Dates		71d	04-Aug-16	16-Nov-16
S4-OD-MS-1010	Structure Mill Order Date - Segment 4	0d	04-Aug-16	
S4-OD-MS-1020	Anchor Bolts Order Date - Segment 4	0d	16-Nov-16	
S4-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 4	0d	16-Nov-16	
S4-OD-MS-1040	Conductor Order Date - Segment 4	0d	16-Nov-16	
S4-OD-MS-1050	OPGW Order Date - Segment 4	0d	16-Nov-16	
S4-OD-MS-1060	Structure Release Date - Segment 4	0d	16-Nov-16	
S4-OD-MS-1070	OHGW Order Date - Segment 4	0d	16-Nov-16	
Received Dates		170d	30-Dec-16	06-Sep-17
S4-RD-MS-1010	Anchor Bolts Received Date - Segment 4	0d		30-Dec-16
S4-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segment 4	0d		30-Dec-16
S4-RD-MS-1050	Conductor Received Date - Segment 4	0d		28-Mar-17
S4-RD-MS-1040	OPGW Received Date - Segment 4	0d		28-Mar-17
S4-RD-MS-1030	OHGW Materials recieved Date - Segment 4	0d		28-Mar-17
S4-RD-MS-1060	Structure Materials Received Date - Segment 4	0d		06-Sep-17
Completion Dates		162d	13-Jun-17	05-Feb-18
S4-CD-MS-1010	Access Roads Complete - Segment 4	0d		13-Jun-17
S4-CD-MS-1020	Foundations Complete - Segment 4	0d		02-Aug-17
S4-CD-MS-1030	Structure Installation Complete - Segment 4	0d		13-Dec-17
S4-CD-MS-1040	Conductor Installation Complete - Segment 4	0d		24-Jan-18
S4-CD-MS-1050	OHGW Complete - Segment 4	0d		24-Jan-18



🟩 Remaining Level of Effort ▬ % Complete
🟦 Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

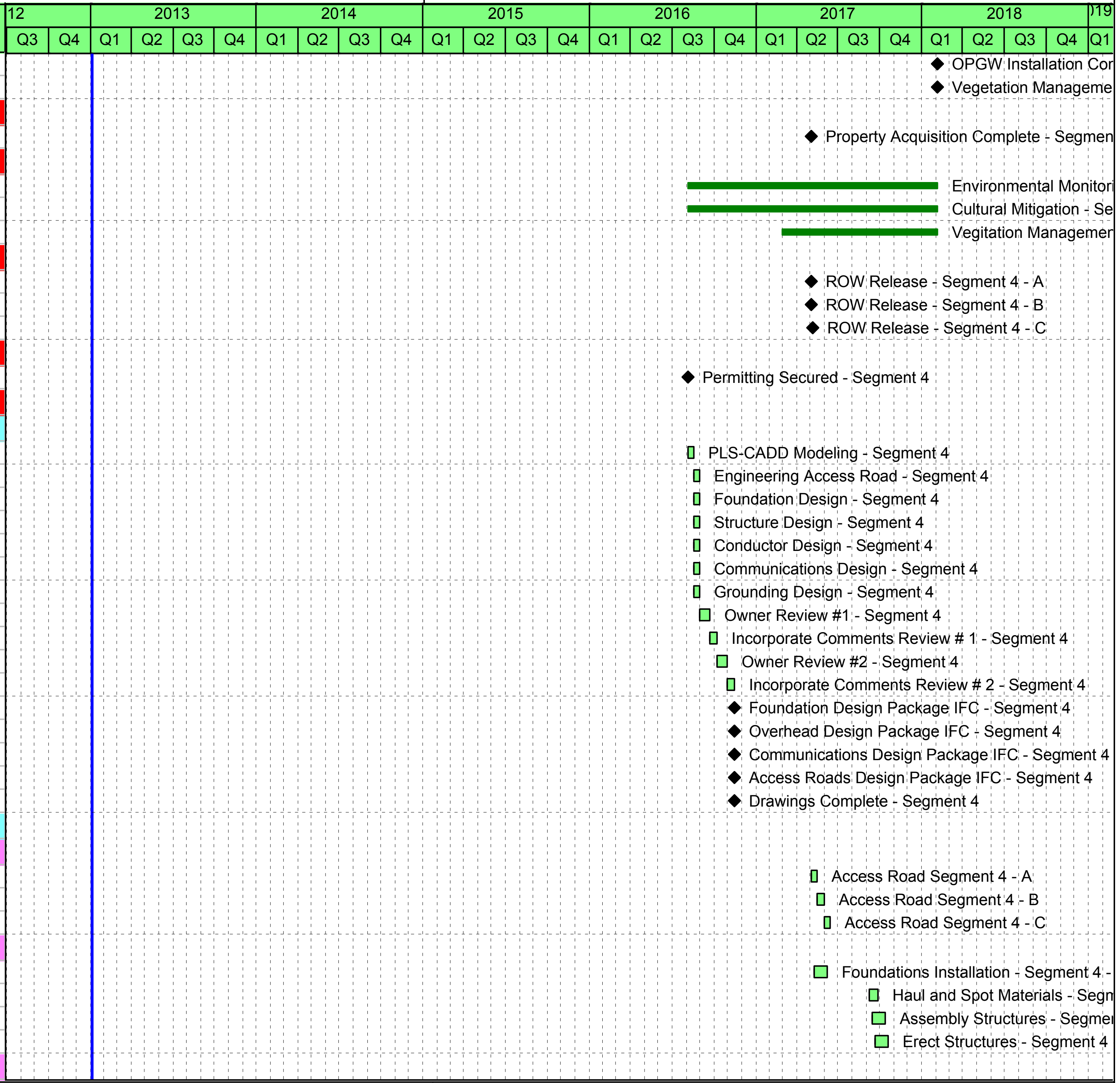
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S4-CD-MS-1060	OPGW Installation Complete - Segment 4	0d		05-Feb-18
S4-CD-MS-1070	Vegetation Management Complete - Segment 4	0d		05-Feb-18
Property		0d	03-May-17	03-May-17
S4-PRP-1000	Property Acquisition Complete - Segment 4	0d		03-May-17
Environmental		374d	04-Aug-16	05-Feb-18
S4-ENV-1000	Environmental Monitoring- Segment 4	374d	04-Aug-16	05-Feb-18
S4-ENV-1010	Cultural Mitigation - Segment 4	374d	04-Aug-16	05-Feb-18
S4-ENV-1020	Vegitation Management - Segment 4	235d	27-Feb-17	05-Feb-18
Right of Way		2d	03-May-17	05-May-17
S4-ROW-1000	ROW Release - Segment 4 - A	0d	03-May-17	
S4-ROW-1010	ROW Release - Segment 4 - B	0d	04-May-17	
S4-ROW-1020	ROW Release - Segment 4 - C	0d	05-May-17	
Permitting		0d	04-Aug-16	04-Aug-16
S4-PMT-1000	Permitting Secured - Segment 4	0d		04-Aug-16
Transmission Lines		374d	04-Aug-16	05-Feb-18
Engineering-T-Line		71d	04-Aug-16	16-Nov-16
S4-ENG-1000	PLS-CADD Modeling - Segment 4	10d	04-Aug-16	18-Aug-16
S4-ENG-1010	Engineering Access Road - Segment 4	10d	18-Aug-16	01-Sep-16
S4-ENG-1020	Foundation Design - Segment 4	10d	18-Aug-16	01-Sep-16
S4-ENG-1030	Structure Design - Segment 4	10d	18-Aug-16	01-Sep-16
S4-ENG-1040	Conductor Design - Segment 4	10d	18-Aug-16	01-Sep-16
S4-ENG-1050	Communications Design - Segment 4	10d	18-Aug-16	01-Sep-16
S4-ENG-1060	Grounding Design - Segment 4	10d	18-Aug-16	01-Sep-16
S4-ENG-1070	Owner Review #1 - Segment 4	15d	01-Sep-16	23-Sep-16
S4-ENG-1080	Incorporate Comments Review # 1 - Segment 4	10d	23-Sep-16	07-Oct-16
S4-ENG-1090	Owner Review #2 - Segment 4	15d	07-Oct-16	31-Oct-16
S4-ENG-1100	Incorporate Comments Review # 2 - Segment 4	10d	31-Oct-16	15-Nov-16
S4-ENG-1120	Foundation Design Package IFC - Segment 4	0d		15-Nov-16
S4-ENG-1130	Overhead Design Package IFC - Segment 4	0d		15-Nov-16
S4-ENG-1140	Communications Design Package IFC - Segment 4	0d		15-Nov-16
S4-ENG-1150	Access Roads Design Package IFC - Segment 4	0d		15-Nov-16
S4-ENG-1160	Drawings Complete - Segment 4	0d		16-Nov-16
Construction-T-Line		190d	03-May-17	05-Feb-18
Access Roads		28d	03-May-17	13-Jun-17
S4-AR-1000	Access Road Segment 4 - A	10d	03-May-17	17-May-17
S4-AR-1010	Access Road Segment 4 - B	10d	17-May-17	01-Jun-17
S4-AR-1020	Access Road Segment 4 - C	8d	01-Jun-17	13-Jun-17
Section A		112d	10-May-17	19-Oct-17
S4-A-001	Foundations Installation - Segment 4 - A	20d	10-May-17	08-Jun-17
S4-A-002	Haul and Spot Materials - Segment 4 - A	15d	06-Sep-17	27-Sep-17
S4-A-003	Assembly Structures - Segment 4 - A	20d	13-Sep-17	11-Oct-17
S4-A-004	Erect Structures - Segment 4 - A	20d	20-Sep-17	19-Oct-17
Section B		112d	08-Jun-17	17-Nov-17



🟩 Remaining Level of Effort ▬ % Complete
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

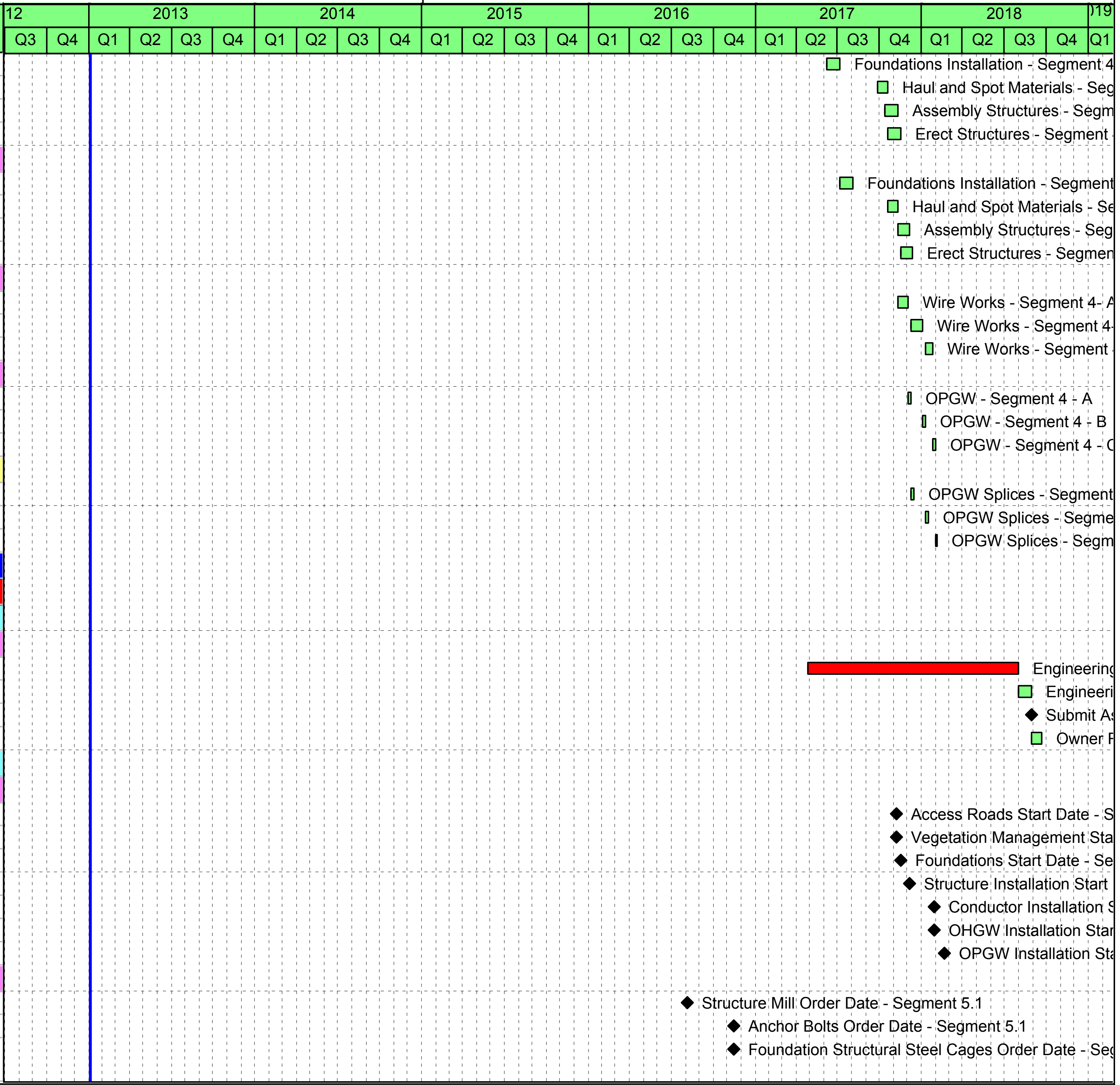
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S4-B-001	Foundations Installation - Segment 4 - B	20d	08-Jun-17	07-Jul-17
S4-B-002	Haul and Spot Materials - Segment 4 - B	15d	27-Sep-17	19-Oct-17
S4-B-003	Assembly Structures - Segment 4 - B	20d	11-Oct-17	09-Nov-17
S4-B-004	Erect Structures - Segment 4 - B	20d	19-Oct-17	17-Nov-17
Section C		110d	07-Jul-17	13-Dec-17
S4-C-001	Foundations Installation - Segment 4 - C	18d	07-Jul-17	02-Aug-17
S4-C-002	Haul and Spot Materials - Segment 4 - C	15d	19-Oct-17	09-Nov-17
S4-C-003	Assembly Structures - Segment 4 - C	18d	09-Nov-17	06-Dec-17
S4-C-004	Erect Structures - Segment 4 - C	18d	17-Nov-17	13-Dec-17
Wire Runs		50d	09-Nov-17	24-Jan-18
S4-CN-1000	Wire Works - Segment 4- A	15d	09-Nov-17	01-Dec-17
S4-CN-1010	Wire Works - Segment 4- B	15d	08-Dec-17	03-Jan-18
S4-CN-1020	Wire Works - Segment 4- C	12d	08-Jan-18	24-Jan-18
Communications		43d	01-Dec-17	05-Feb-18
S4-CM-1000	OPGW - Segment 4 - A	5d	01-Dec-17	08-Dec-17
S4-CM-1010	OPGW - Segment 4 - B	5d	03-Jan-18	10-Jan-18
S4-CM-1020	OPGW - Segment 4 - C	4d	24-Jan-18	30-Jan-18
Splices		38d	08-Dec-17	05-Feb-18
S4-CMS-1000	OPGW Splices - Segment 4 - A	5d	08-Dec-17	15-Dec-17
S4-CMS-1010	OPGW Splices - Segment 4 - B	5d	10-Jan-18	17-Jan-18
S4-CMS-1020	OPGW Splices - Segment 4 - C	4d	30-Jan-18	05-Feb-18
Segment 5 White River - Wawa (118km)		529d	04-Aug-16	20-Sep-18
Segment 5.1 (60 kilometers)		529d	04-Aug-16	20-Sep-18
Project Management		350d	26-Apr-17	20-Sep-18
Project Support		350d	26-Apr-17	20-Sep-18
S5.1-ENG-9000	Engineering Construction Support - Segment 5.1	315d	26-Apr-17	31-Jul-18
S5.1-ENG-9010	Engineering As-Builts - Segment 5.1	20d	31-Jul-18	29-Aug-18
S5.1-ENG-9020	Submit As-Builts - Segment 5.1	0d		29-Aug-18
S5.1-ENG-9030	Owner Review As-Builts - Segment 5.1	15d	29-Aug-18	20-Sep-18
Contractor Milestones Segment 5.1		494d	04-Aug-16	31-Jul-18
Start Dates		70d	08-Nov-17	21-Feb-18
S5.1-SD-MS-1010	Access Roads Start Date - Segment 5.1	0d	08-Nov-17	
S5.1-SD-MS-1020	Vegetation Management Start Date - Segment 5.1	0d	08-Nov-17	
S5.1-SD-MS-1030	Foundations Start Date - Segment 5.1	0d	16-Nov-17	
S5.1-SD-MS-1040	Structure Installation Start Date - Segment 5.1	0d	07-Dec-17	
S5.1-SD-MS-1050	Conductor Installation Start Date - Segment 5.1	0d	30-Jan-18	
S5.1-SD-MS-1060	OHGW Installation Start Date - Segment 5.1	0d	30-Jan-18	
S5.1-SD-MS-1070	OPGW Installation Start Date - Segment 5.1	0d	21-Feb-18	
Order Dates		71d	04-Aug-16	16-Nov-16
S5.1-OD-MS-1010	Structure Mill Order Date - Segment 5.1	0d	04-Aug-16	
S5.1-OD-MS-1020	Anchor Bolts Order Date - Segment 5.1	0d	16-Nov-16	
S5.1-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 5.1	0d	16-Nov-16	



🟩 Remaining Level of Effort
▬ % Complete
🟦 Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

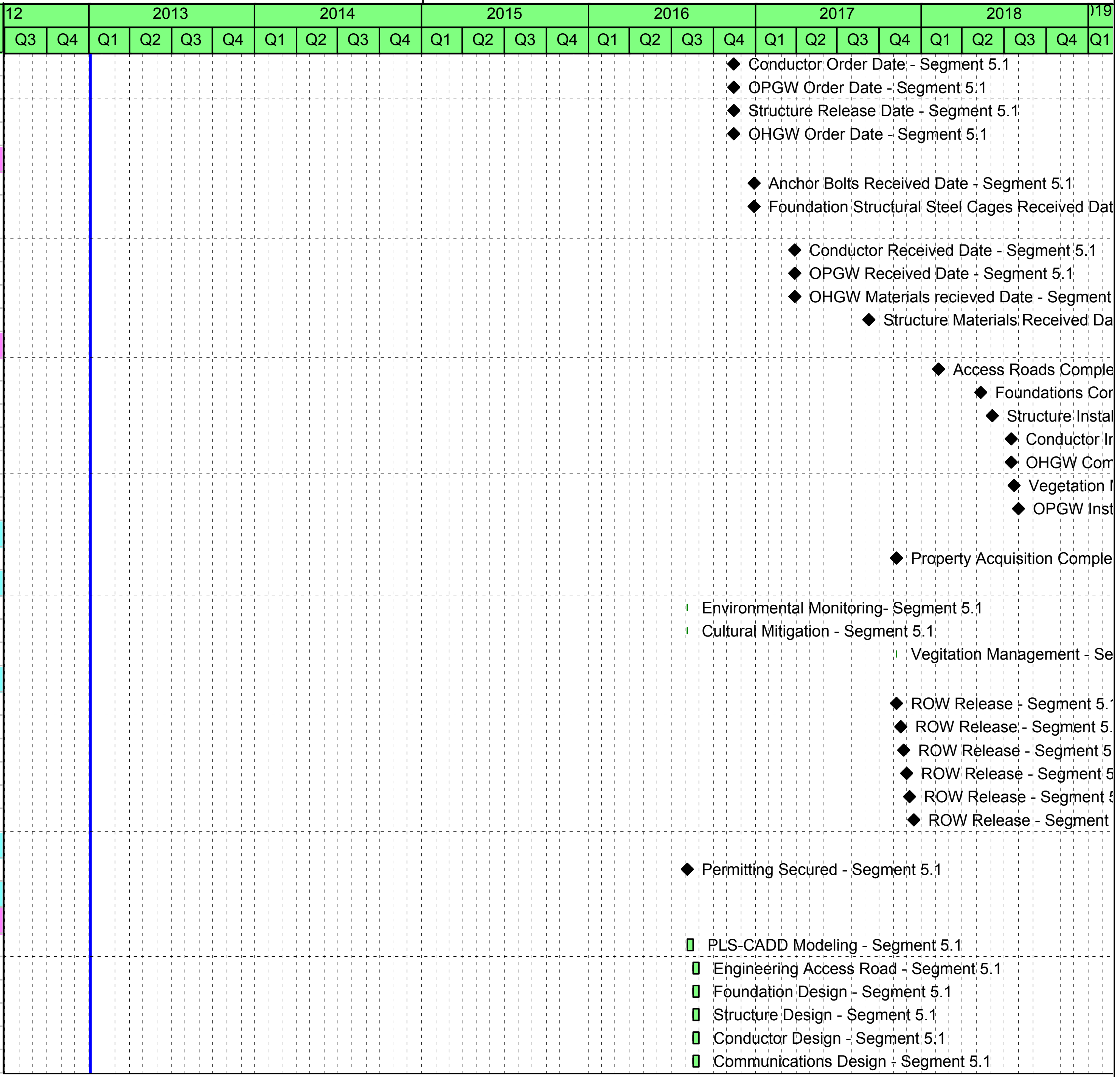
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S5.1-OD-MS-1040	Conductor Order Date - Segment 5.1	0d	16-Nov-16	
S5.1-OD-MS-1050	OPGW Order Date - Segment 5.1	0d	16-Nov-16	
S5.1-OD-MS-1060	Structure Release Date - Segment 5.1	0d	16-Nov-16	
S5.1-OD-MS-1070	OHGW Order Date - Segment 5.1	0d	16-Nov-16	
Received Dates		170d	30-Dec-16	06-Sep-17
S5.1-RD-MS-1010	Anchor Bolts Received Date - Segment 5.1	0d		30-Dec-16
S5.1-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segment 5.1	0d		30-Dec-16
S5.1-RD-MS-1050	Conductor Received Date - Segment 5.1	0d		28-Mar-17
S5.1-RD-MS-1040	OPGW Received Date - Segment 5.1	0d		28-Mar-17
S5.1-RD-MS-1030	OHGW Materials recieved Date - Segment 5.1	0d		28-Mar-17
S5.1-RD-MS-1060	Structure Materials Received Date - Segment 5.1	0d		06-Sep-17
Completion Dates		120d	06-Feb-18	31-Jul-18
S5.1-CD-MS-1010	Access Roads Complete - Segment 5.1	0d		06-Feb-18
S5.1-CD-MS-1020	Foundations Complete - Segment 5.1	0d		11-May-18
S5.1-CD-MS-1030	Structure Installation Complete - Segment 5.1	0d		04-Jun-18
S5.1-CD-MS-1040	Conductor Installation Complete - Segment 5.1	0d		17-Jul-18
S5.1-CD-MS-1060	OHGW Complete - Segment 5.1	0d		17-Jul-18
S5.1-CD-MS-1050	Vegetation Management Complete - Segment 5.1	0d		24-Jul-18
S5.1-CD-MS-1070	OPGW Installation Complete - Segment 5.1	0d		31-Jul-18
Property		0d	08-Nov-17	08-Nov-17
S5.1-PRP-1000	Property Acquisition Complete - Segment 5.1	0d		08-Nov-17
Environmental		314d	04-Aug-16	08-Nov-17
S5.1-ENV-1000	Environmental Monitoring- Segment 5.1	0d	04-Aug-16	04-Aug-16
S5.1-ENV-1010	Cultural Mitigation - Segment 5.1	0d	04-Aug-16	04-Aug-16
S5.1-ENV-1020	Vegitation Management - Segment 5.1	0d	08-Nov-17	08-Nov-17
Right of Way		25d	08-Nov-17	14-Dec-17
S5.1-ROW-1000	ROW Release - Segment 5.1 - A	0d	08-Nov-17	
S5.1-ROW-1010	ROW Release - Segment 5.1 - B	0d	16-Nov-17	
S5.1-ROW-1020	ROW Release - Segment 5.1 - C	0d	23-Nov-17	
S5.1-ROW-1030	ROW Release - Segment 5.1 - D	0d	30-Nov-17	
S5.1-ROW-1040	ROW Release - Segment 5.1 - E	0d	07-Dec-17	
S5.1-ROW-1050	ROW Release - Segment 5.1 - F	0d	14-Dec-17	
Permitting		0d	04-Aug-16	04-Aug-16
S5.1-PMT-1000	Permitting Secured - Segment 5.1	0d		04-Aug-16
Transmission Lines		494d	04-Aug-16	31-Jul-18
Engineering-T-Line		71d	04-Aug-16	16-Nov-16
S5.1-ENG-1000	PLS-CADD Modeling - Segment 5.1	10d	04-Aug-16	18-Aug-16
S5.1-ENG-1010	Engineering Access Road - Segment 5.1	10d	18-Aug-16	01-Sep-16
S5.1-ENG-1020	Foundation Design - Segment 5.1	10d	18-Aug-16	01-Sep-16
S5.1-ENG-1030	Structure Design - Segment 5.1	10d	18-Aug-16	01-Sep-16
S5.1-ENG-1040	Conductor Design - Segment 5.1	10d	18-Aug-16	01-Sep-16
S5.1-ENG-1050	Communications Design - Segment 5.1	10d	18-Aug-16	01-Sep-16



🟩	Remaining Level of Effort
▬	% Complete
🟦	Actual Level of Effort
🟦	Actual Work
🟩	Remaining Work
🟥	Critical Remaining Work
◆ ◆	Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

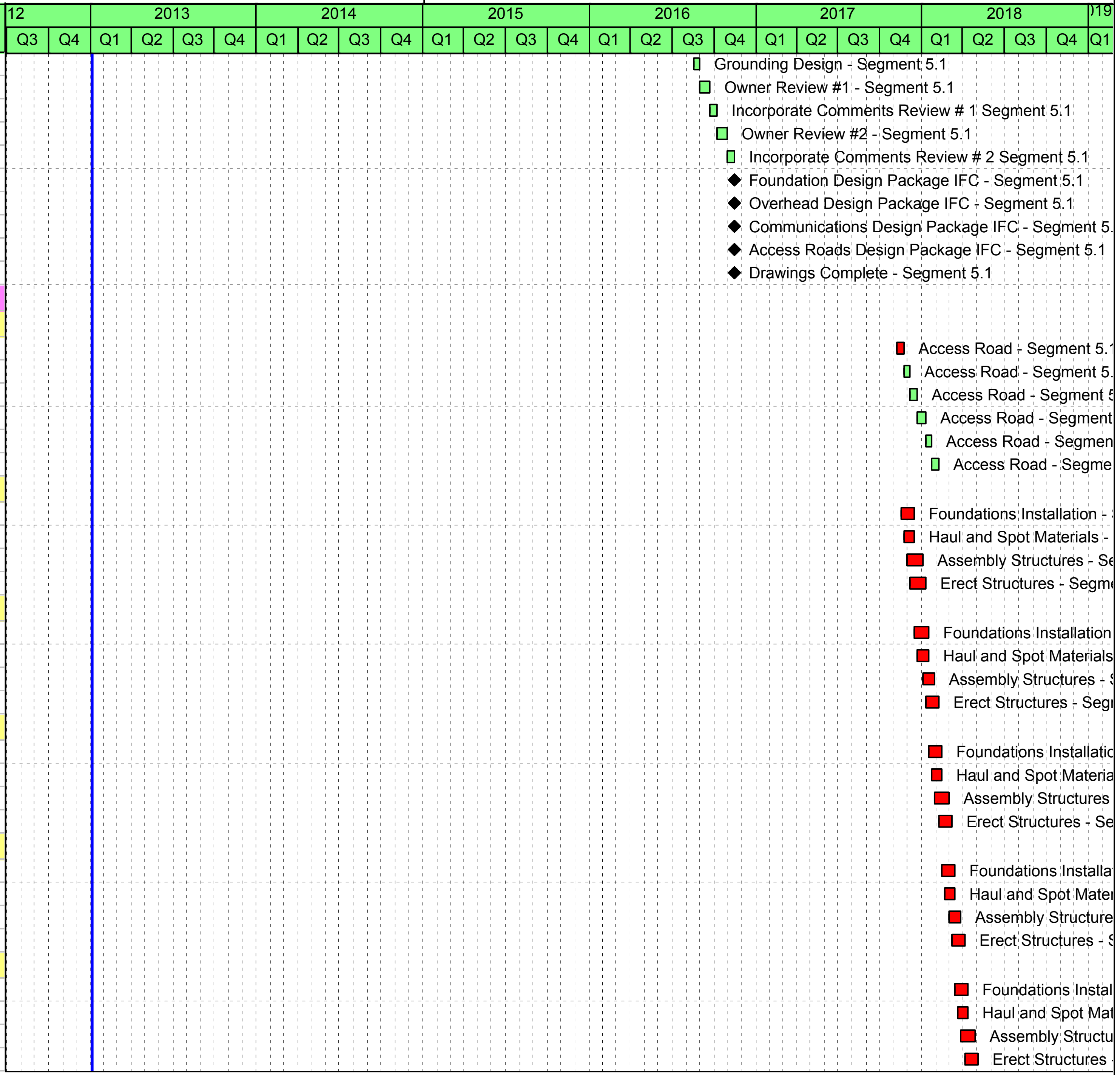
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S5.1-ENG-1060	Grounding Design - Segment 5.1	10d	18-Aug-16	01-Sep-16
S5.1-ENG-1070	Owner Review #1 - Segment 5.1	15d	01-Sep-16	23-Sep-16
S5.1-ENG-1080	Incorporate Comments Review # 1 Segment 5.1	10d	23-Sep-16	07-Oct-16
S5.1-ENG-1090	Owner Review #2 - Segment 5.1	15d	07-Oct-16	31-Oct-16
S5.1-ENG-1100	Incorporate Comments Review # 2 Segment 5.1	10d	31-Oct-16	15-Nov-16
S5.1-ENG-1120	Foundation Design Package IFC - Segment 5.1	0d		15-Nov-16
S5.1-ENG-1130	Overhead Design Package IFC - Segment 5.1	0d		15-Nov-16
S5.1-ENG-1140	Communications Design Package IFC - Segment 5.1	0d		15-Nov-16
S5.1-ENG-1150	Access Roads Design Package IFC - Segment 5.1	0d		15-Nov-16
S5.1-ENG-1160	Drawings Complete - Segment 5.1	0d		16-Nov-16
Construction-T-Line		180d	08-Nov-17	31-Jul-18
Access Roads		60d	08-Nov-17	06-Feb-18
S5.1-AR-1000	Access Road - Segment 5.1 - A	10d	08-Nov-17	23-Nov-17
S5.1-AR-1010	Access Road - Segment 5.1 - B	10d	23-Nov-17	07-Dec-17
S5.1-AR-1020	Access Road - Segment 5.1 - C	10d	07-Dec-17	21-Dec-17
S5.1-AR-1030	Access Road - Segment 5.1 - D	10d	21-Dec-17	09-Jan-18
S5.1-AR-1040	Access Road - Segment 5.1 - E	10d	09-Jan-18	23-Jan-18
S5.1-AR-1050	Access Road - Segment 5.1 - F	10d	23-Jan-18	06-Feb-18
Section A		35d	16-Nov-17	09-Jan-18
S5.1-A-001	Foundations Installation - Segment 5.1 - A	20d	16-Nov-17	14-Dec-17
S5.1-A-002	Haul and Spot Materials - Segment 5.1 - A	15d	23-Nov-17	14-Dec-17
S5.1-A-003	Assembly Structures - Segment 5.1 - A	20d	30-Nov-17	02-Jan-18
S5.1-A-004	Erect Structures - Segment 5.1 - A	20d	07-Dec-17	09-Jan-18
Section B		35d	14-Dec-17	06-Feb-18
S5.1-B-001	Foundations Installation - Segment 5.1 - B	20d	14-Dec-17	16-Jan-18
S5.1-B-002	Haul and Spot Materials - Segment 5.1 - B	15d	21-Dec-17	16-Jan-18
S5.1-B-003	Assembly Structures - Segment 5.1 - B	20d	02-Jan-18	30-Jan-18
S5.1-B-004	Erect Structures - Segment 5.1 - B	20d	09-Jan-18	06-Feb-18
Section C		35d	16-Jan-18	07-Mar-18
S5.1-C-001	Foundations Installation - Segment 5.1 - C	20d	16-Jan-18	13-Feb-18
S5.1-C-002	Haul and Spot Materials - Segment 5.1 - C	15d	23-Jan-18	13-Feb-18
S5.1-C-003	Assembly Structures - Segment 5.1 - C	20d	30-Jan-18	28-Feb-18
S5.1-C-004	Erect Structures - Segment 5.1 - C	20d	06-Feb-18	07-Mar-18
Section D		35d	13-Feb-18	06-Apr-18
S5.1-D-001	Foundations Installation - Segment 5.1 - D	20d	13-Feb-18	14-Mar-18
S5.1-D-002	Haul and Spot Materials - Segment 5.1 - D	15d	21-Feb-18	14-Mar-18
S5.1-D-003	Assembly Structures - Segment 5.1 - D	20d	28-Feb-18	28-Mar-18
S5.1-D-004	Erect Structures - Segment 5.1 - D	20d	07-Mar-18	06-Apr-18
Section E		35d	14-Mar-18	04-May-18
S5.1-E-001	Foundations Installation - Segment 5.1 - E	20d	14-Mar-18	13-Apr-18
S5.1-E-002	Haul and Spot Materials - Segment 5.1 - E	15d	21-Mar-18	13-Apr-18
S5.1-E-003	Assembly Structures - Segment 5.1 - E	20d	28-Mar-18	27-Apr-18
S5.1-E-004	Erect Structures - Segment 5.1 - E	20d	06-Apr-18	04-May-18



🟩 Remaining Level of Effort ▬ % Complete
🟦 Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

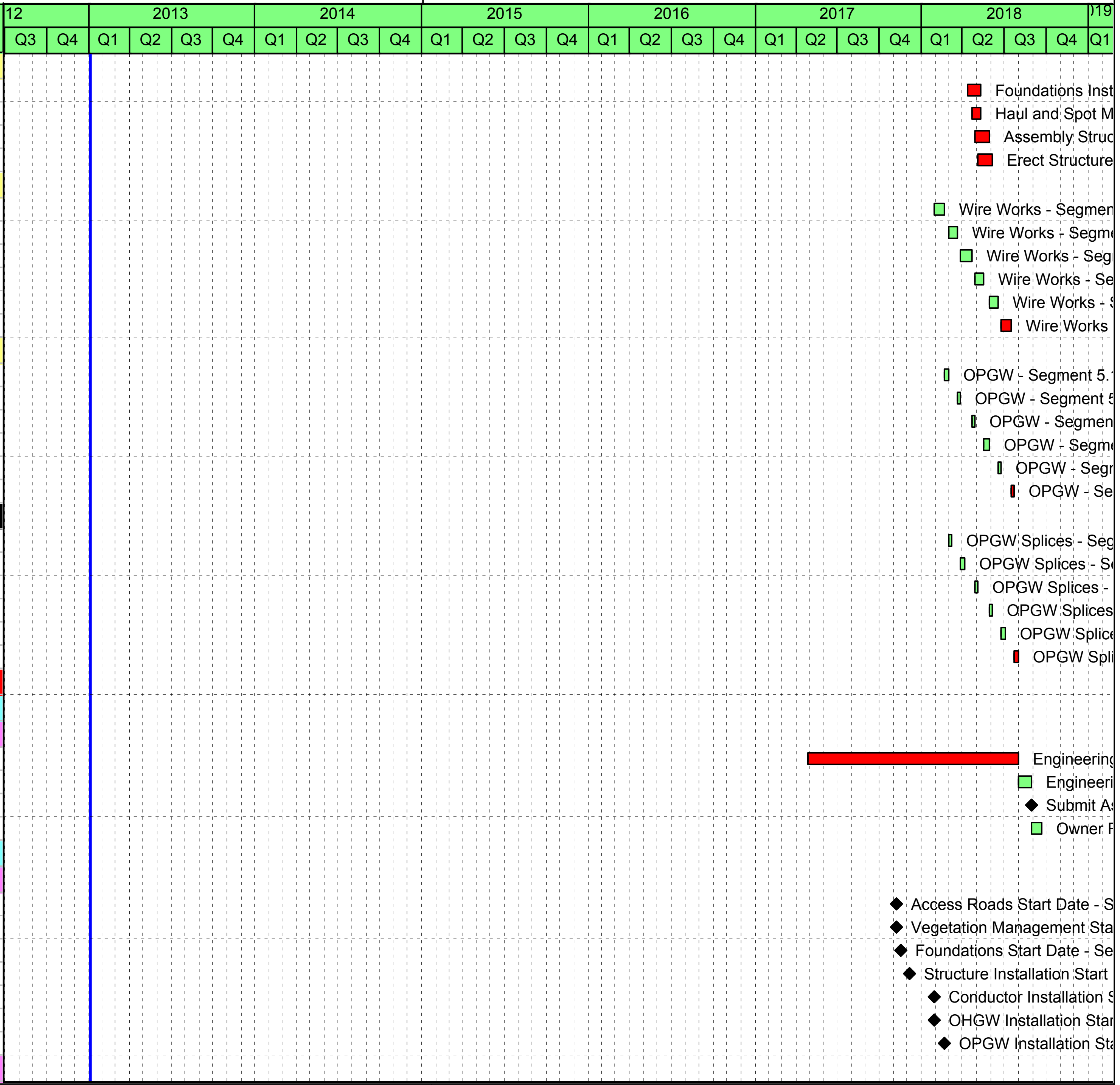
Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

Activity ID	Activity Name	Original Duration	Start	Finish
Section F		35d	13-Apr-18	04-Jun-18
S5.1-F-001	Foundations Installation - Segment 5.1 - F	20d	13-Apr-18	11-May-18
S5.1-F-002	Haul and Spot Materials - Segment 5.1 - F	15d	20-Apr-18	11-May-18
S5.1-F-003	Assembly Structures - Segment 5.1 - F	20d	27-Apr-18	28-May-18
S5.1-F-004	Erect Structures - Segment 5.1 - F	20d	04-May-18	04-Jun-18
Wire Runs		115d	30-Jan-18	17-Jul-18
S5.1-CN-1000	Wire Works - Segment 5.1 - A	15d	30-Jan-18	21-Feb-18
S5.1-CN-1010	Wire Works - Segment 5.1 - B	15d	28-Feb-18	21-Mar-18
S5.1-CN-1020	Wire Works - Segment 5.1 - C	15d	28-Mar-18	20-Apr-18
S5.1-CN-1030	Wire Works - Segment 5.1 - D	15d	27-Apr-18	18-May-18
S5.1-CN-1040	Wire Works - Segment 5.1 - E	15d	28-May-18	18-Jun-18
S5.1-CN-1050	Wire Works - Segment 5.1 - F	15d	25-Jun-18	17-Jul-18
Communications		110d	21-Feb-18	31-Jul-18
S5.1-CM-1000	OPGW - Segment 5.1 - A	5d	21-Feb-18	28-Feb-18
S5.1-CM-1010	OPGW - Segment 5.1 - B	5d	21-Mar-18	28-Mar-18
S5.1-CM-1020	OPGW - Segment 5.1 - C	5d	20-Apr-18	27-Apr-18
S5.1-CM-1030	OPGW - Segment 5.1 - D	5d	18-May-18	28-May-18
S5.1-CM-1040	OPGW - Segment 5.1 - E	5d	18-Jun-18	25-Jun-18
S5.1-CM-1050	OPGW - Segment 5.1 - F	5d	17-Jul-18	24-Jul-18
Splices		105d	28-Feb-18	31-Jul-18
S5.1-CMS-1000	OPGW Splices - Segment 5.1 - A	5d	28-Feb-18	07-Mar-18
S5.1-CMS-1010	OPGW Splices - Segment 5.1 - B	5d	28-Mar-18	06-Apr-18
S5.1-CMS-1020	OPGW Splices - Segment 5.1 - C	5d	27-Apr-18	04-May-18
S5.1-CMS-1030	OPGW Splices - Segment 5.1 - D	5d	28-May-18	04-Jun-18
S5.1-CMS-1040	OPGW Splices - Segment 5.1 - E	5d	25-Jun-18	03-Jul-18
S5.1-CMS-1050	OPGW Splices - Segment 5.1 - F	5d	24-Jul-18	31-Jul-18
Segment 5.2 (58 kilometers)		529d	04-Aug-16	20-Sep-18
Project Management		350d	26-Apr-17	20-Sep-18
Project Support		350d	26-Apr-17	20-Sep-18
S5.2-ENG-9000	Engineering Construction Support - Segment 5.2	315d	26-Apr-17	31-Jul-18
S5.2-ENG-9010	Engineering As-Builts - Segment 5.2	20d	31-Jul-18	29-Aug-18
S5.2-ENG-9020	Submit As-Builts - Segment 5.2	0d		29-Aug-18
S5.2-ENG-9030	Owner Review As-Builts - Segment 5.2	15d	29-Aug-18	20-Sep-18
Contractor Milestones Segment 5.2		494d	04-Aug-16	31-Jul-18
Start Dates		70d	08-Nov-17	21-Feb-18
S5.2-SD-MS-1010	Access Roads Start Date - Segment 5.2	0d	08-Nov-17	
S5.2-SD-MS-1020	Vegetation Management Start Date - Segment 5.2	0d	08-Nov-17	
S5.2-SD-MS-1030	Foundations Start Date - Segment 5.2	0d	16-Nov-17	
S5.2-SD-MS-1040	Structure Installation Start Date - Segment 5.2	0d	07-Dec-17	
S5.2-SD-MS-1050	Conductor Installation Start Date - Segment 5.2	0d	30-Jan-18	
S5.2-SD-MS-1060	OHGW Installation Start Date - Segment 5.2	0d	30-Jan-18	
S5.2-SD-MS-1070	OPGW Installation Start Date - Segment 5.2	0d	21-Feb-18	
Order Dates		71d	04-Aug-16	16-Nov-16



- 🟩 Remaining Level of Effort
- ▬ % Complete
- 🟦 Actual Level of Effort
- 🟦 Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

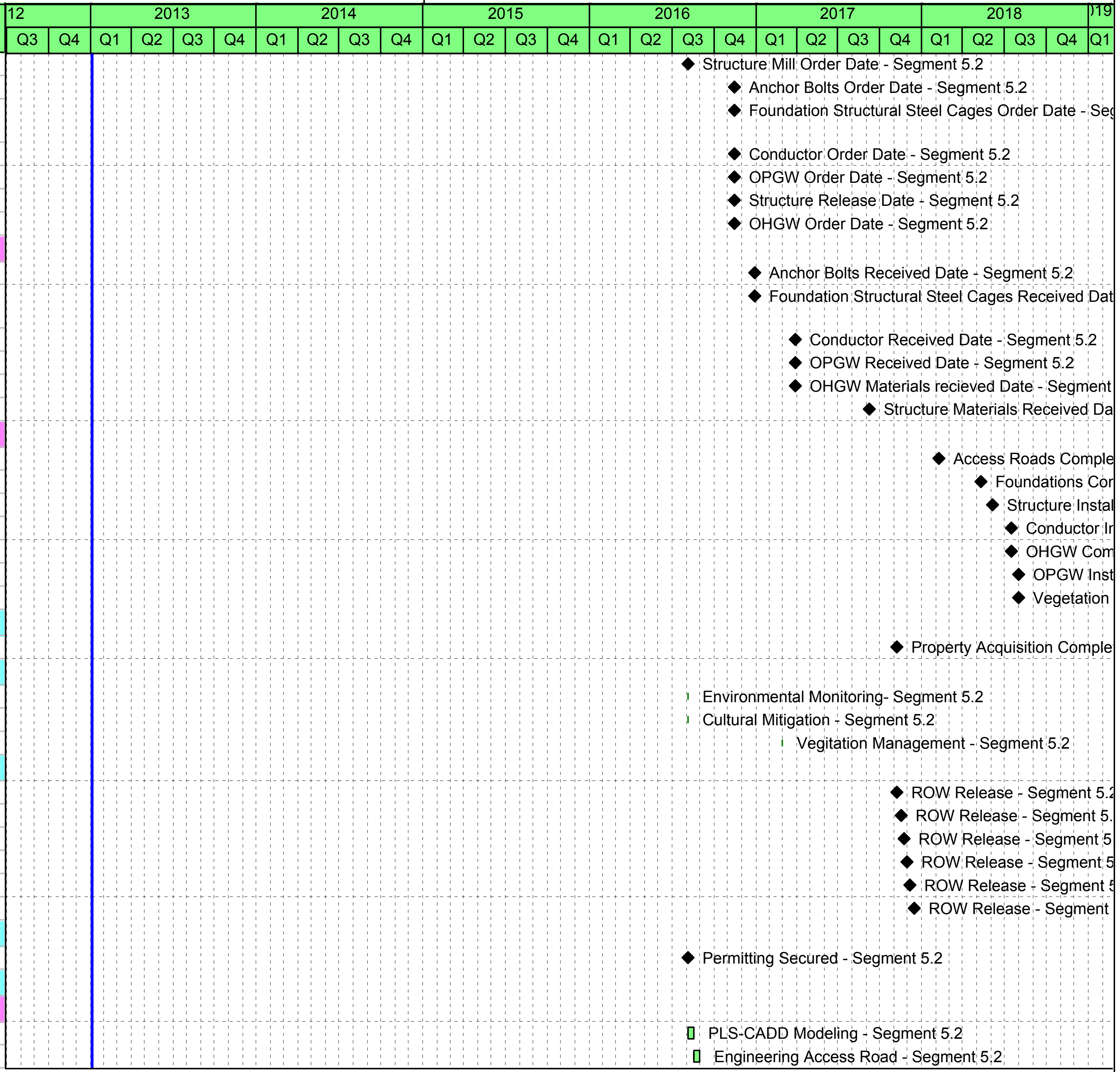
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S5.2-OD-MS-1010	Structure Mill Order Date - Segment 5.2	0d	04-Aug-16	
S5.2-OD-MS-1020	Anchor Bolts Order Date - Segment 5.2	0d	16-Nov-16	
S5.2-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 5.2	0d	16-Nov-16	
S5.2-OD-MS-1040	Conductor Order Date - Segment 5.2	0d	16-Nov-16	
S5.2-OD-MS-1050	OPGW Order Date - Segment 5.2	0d	16-Nov-16	
S5.2-OD-MS-1060	Structure Release Date - Segment 5.2	0d	16-Nov-16	
S5.2-OD-MS-1070	OHGW Order Date - Segment 5.2	0d	16-Nov-16	
Received Dates		170d	30-Dec-16	06-Sep-17
S5.2-RD-MS-1010	Anchor Bolts Received Date - Segment 5.2	0d		30-Dec-16
S5.2-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segment 5.2	0d		30-Dec-16
S5.2-RD-MS-1050	Conductor Received Date - Segment 5.2	0d		28-Mar-17
S5.2-RD-MS-1040	OPGW Received Date - Segment 5.2	0d		28-Mar-17
S5.2-RD-MS-1030	OHGW Materials recieved Date - Segment 5.2	0d		28-Mar-17
S5.2-RD-MS-1060	Structure Materials Received Date - Segment 5.2	0d		06-Sep-17
Completion Dates		120d	06-Feb-18	31-Jul-18
S5.2-CD-MS-1010	Access Roads Complete - Segment 5.2	0d		06-Feb-18
S5.2-CD-MS-1020	Foundations Complete - Segment 5.2	0d		11-May-18
S5.2-CD-MS-1030	Structure Installation Complete - Segment 5.2	0d		04-Jun-18
S5.2-CD-MS-1040	Conductor Installation Complete - Segment 5.2	0d		17-Jul-18
S5.2-CD-MS-1060	OHGW Complete - Segment 5.2	0d		17-Jul-18
S5.2-CD-MS-1070	OPGW Installation Complete - Segment 5.2	0d		31-Jul-18
S5.2-CD-MS-1050	Vegetation Management Complete - Segment 5.2	0d		31-Jul-18
Property		0d	08-Nov-17	08-Nov-17
S5.2-PRP-1000	Property Acquisition Complete - Segment 5.2	0d		08-Nov-17
Environmental		139d	04-Aug-16	27-Feb-17
S5.2-ENV-1010	Environmental Monitoring- Segment 5.2	0d	04-Aug-16	04-Aug-16
S5.2-ENV-1020	Cultural Mitigation - Segment 5.2	0d	04-Aug-16	04-Aug-16
S5.2-ENV-1030	Vegitation Management - Segment 5.2	0d	27-Feb-17	27-Feb-17
Right of Way		25d	08-Nov-17	14-Dec-17
S5.2-ROW-1000	ROW Release - Segment 5.2 - A	0d	08-Nov-17	
S5.2-ROW-1010	ROW Release - Segment 5.2 - B	0d	16-Nov-17	
S5.2-ROW-1020	ROW Release - Segment 5.2 - C	0d	23-Nov-17	
S5.2-ROW-1030	ROW Release - Segment 5.2 - D	0d	30-Nov-17	
S5.2-ROW-1040	ROW Release - Segment 5.2 - E	0d	07-Dec-17	
S5.2-ROW-1050	ROW Release - Segment 5.2 - F	0d	14-Dec-17	
Permitting		0d	04-Aug-16	04-Aug-16
S5.2-PMT-1000	Permitting Secured - Segment 5.2	0d		04-Aug-16
Transmission Lines		494d	04-Aug-16	31-Jul-18
Engineering-T-Line		71d	04-Aug-16	16-Nov-16
S5.2-ENG-1000	PLS-CADD Modeling - Segment 5.2	10d	04-Aug-16	18-Aug-16
S5.2-ENG-1010	Engineering Access Road - Segment 5.2	10d	18-Aug-16	01-Sep-16



▬ Remaining Level of Effort ▬ % Complete
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

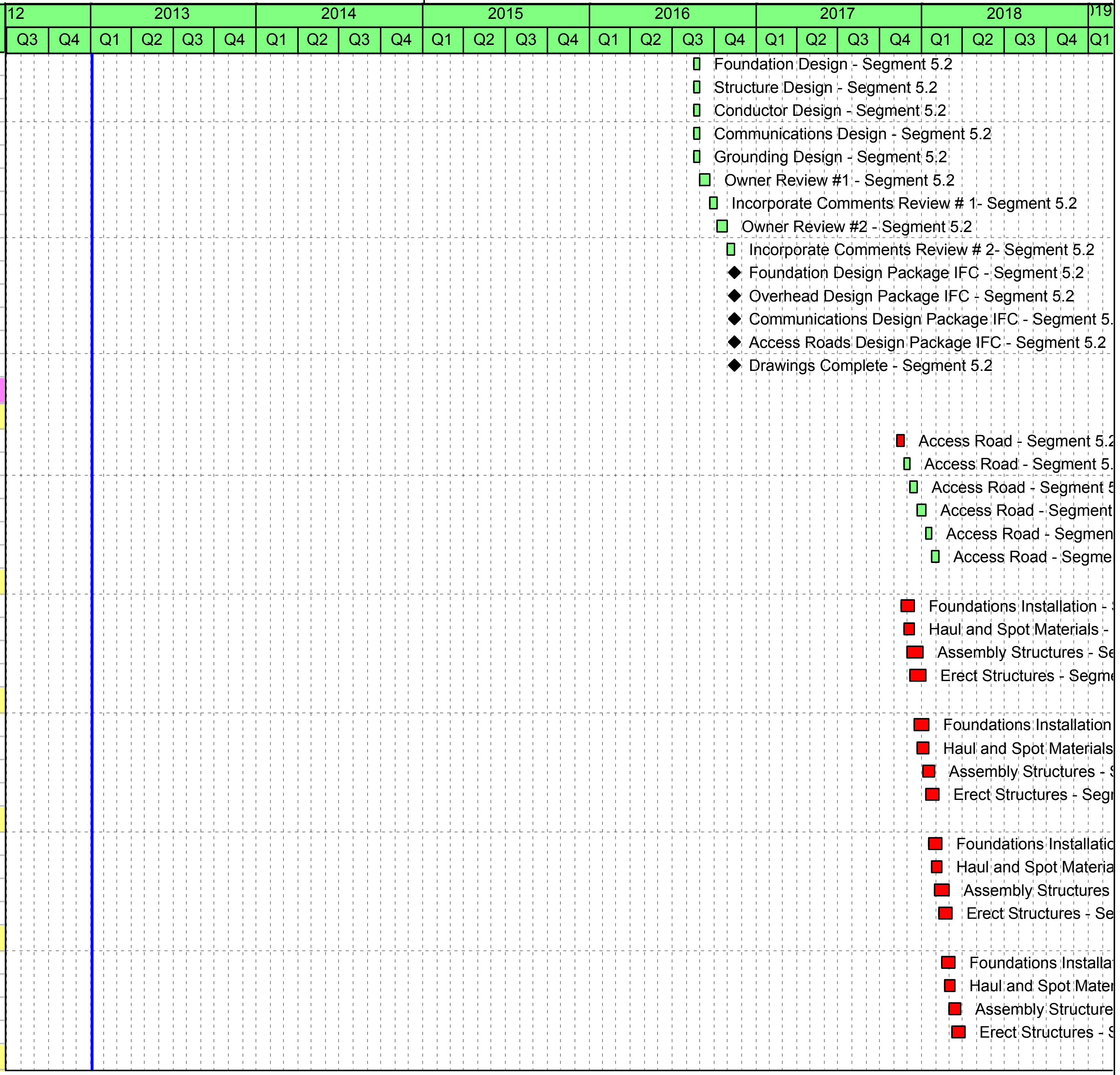
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S5.2-ENG-1020	Foundation Design - Segment 5.2	10d	18-Aug-16	01-Sep-16
S5.2-ENG-1030	Structure Design - Segment 5.2	10d	18-Aug-16	01-Sep-16
S5.2-ENG-1040	Conductor Design - Segment 5.2	10d	18-Aug-16	01-Sep-16
S5.2-ENG-1050	Communications Design - Segment 5.2	10d	18-Aug-16	01-Sep-16
S5.2-ENG-1060	Grounding Design - Segment 5.2	10d	18-Aug-16	01-Sep-16
S5.2-ENG-1070	Owner Review #1 - Segment 5.2	15d	01-Sep-16	23-Sep-16
S5.2-ENG-1080	Incorporate Comments Review # 1- Segment 5.2	10d	23-Sep-16	07-Oct-16
S5.2-ENG-1090	Owner Review #2 - Segment 5.2	15d	07-Oct-16	31-Oct-16
S5.2-ENG-1100	Incorporate Comments Review # 2- Segment 5.2	10d	31-Oct-16	15-Nov-16
S5.2-ENG-1120	Foundation Design Package IFC - Segment 5.2	0d		15-Nov-16
S5.2-ENG-1130	Overhead Design Package IFC - Segment 5.2	0d		15-Nov-16
S5.2-ENG-1140	Communications Design Package IFC - Segment 5.2	0d		15-Nov-16
S5.2-ENG-1150	Access Roads Design Package IFC - Segment 5.2	0d		15-Nov-16
S5.2-ENG-1160	Drawings Complete - Segment 5.2	0d		16-Nov-16
Construction-T-Line		**180d**	**08-Nov-17**	**31-Jul-18**
Access Roads		**60d**	**08-Nov-17**	**06-Feb-18**
S5.2-AR-1000	Access Road - Segment 5.2 - A	10d	08-Nov-17	23-Nov-17
S5.2-AR-1010	Access Road - Segment 5.2 - B	10d	23-Nov-17	07-Dec-17
S5.2-AR-1020	Access Road - Segment 5.2 - C	10d	07-Dec-17	21-Dec-17
S5.2-AR-1030	Access Road - Segment 5.2 - D	10d	21-Dec-17	09-Jan-18
S5.2-AR-1040	Access Road - Segment 5.2 - E	10d	09-Jan-18	23-Jan-18
S5.2-AR-1050	Access Road - Segment 5.2 - F	10d	23-Jan-18	06-Feb-18
Section A		**35d**	**16-Nov-17**	**09-Jan-18**
S5.2-A-001	Foundations Installation - Segment 5.2 - A	20d	16-Nov-17	14-Dec-17
S5.2-A-002	Haul and Spot Materials - Segment 5.2 - A	15d	23-Nov-17	14-Dec-17
S5.2-A-003	Assembly Structures - Segment 5.2 - A	20d	30-Nov-17	02-Jan-18
S5.2-A-004	Erect Structures - Segment 5.2 - A	20d	07-Dec-17	09-Jan-18
Section B		**35d**	**14-Dec-17**	**06-Feb-18**
S5.2-B-001	Foundations Installation - Segment 5.2 - B	20d	14-Dec-17	16-Jan-18
S5.2-B-002	Haul and Spot Materials - Segment 5.2 - B	15d	21-Dec-17	16-Jan-18
S5.2-B-003	Assembly Structures - Segment 5.2 - B	20d	02-Jan-18	30-Jan-18
S5.2-B-004	Erect Structures - Segment 5.2 - B	20d	09-Jan-18	06-Feb-18
Section C		**35d**	**16-Jan-18**	**07-Mar-18**
S5.2-C-001	Foundations Installation - Segment 5.2 - C	20d	16-Jan-18	13-Feb-18
S5.2-C-002	Haul and Spot Materials - Segment 5.2 - C	15d	23-Jan-18	13-Feb-18
S5.2-C-003	Assembly Structures - Segment 5.2 - C	20d	30-Jan-18	28-Feb-18
S5.2-C-004	Erect Structures - Segment 5.2 - C	20d	06-Feb-18	07-Mar-18
Section D		**35d**	**13-Feb-18**	**06-Apr-18**
S5.2-D-001	Foundations Installation - Segment 5.2 - D	20d	13-Feb-18	14-Mar-18
S5.2-D-002	Haul and Spot Materials - Segment 5.2 - D	15d	28-Feb-18	14-Mar-18
S5.2-D-003	Assembly Structures - Segment 5.2 - D	20d	28-Feb-18	28-Mar-18
S5.2-D-004	Erect Structures - Segment 5.2 - D	20d	07-Mar-18	06-Apr-18
Section E		**35d**	**14-Mar-18**	**04-May-18**



🟩	Remaining Level of Effort
▬	% Complete
🟦	Actual Level of Effort
🟦	Actual Work
🟩	Remaining Work
🟥	Critical Remaining Work
◆ ◆	Milestone

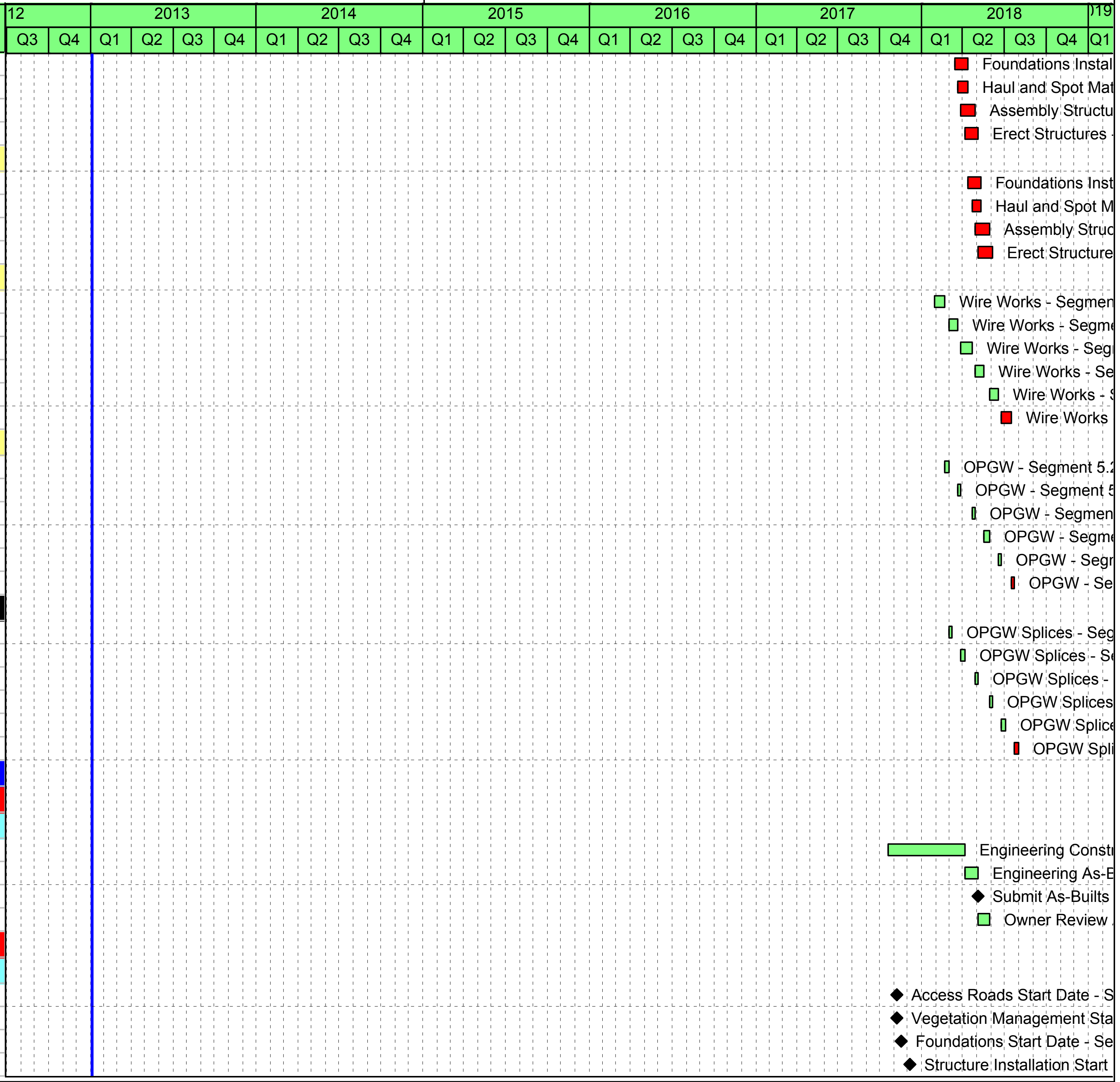
Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

Activity ID	Activity Name	Original Duration	Start	Finish
S5.2-E-001	Foundations Installation - Segment 5.2 - E	20d	14-Mar-18	13-Apr-18
S5.2-E-002	Haul and Spot Materials - Segment 5.2 - E	15d	21-Mar-18	13-Apr-18
S5.2-E-003	Assembly Structures - Segment 5.2 - E	20d	28-Mar-18	27-Apr-18
S5.2-E-004	Erect Structures - Segment 5.2 - E	20d	06-Apr-18	04-May-18
Section F		35d	13-Apr-18	04-Jun-18
S5.2-F-001	Foundations Installation - Segment 5.2 - F	20d	13-Apr-18	11-May-18
S5.2-F-002	Haul and Spot Materials - Segment 5.2 - F	15d	20-Apr-18	11-May-18
S5.2-F-003	Assembly Structures - Segment 5.2 - F	20d	27-Apr-18	28-May-18
S5.2-F-004	Erect Structures - Segment 5.2 - F	20d	04-May-18	04-Jun-18
Wire Runs		115d	30-Jan-18	17-Jul-18
S5.2-CN-1000	Wire Works - Segment 5.2 - A	15d	30-Jan-18	21-Feb-18
S5.2-CN-1010	Wire Works - Segment 5.2 - B	15d	28-Feb-18	21-Mar-18
S5.2-CN-1020	Wire Works - Segment 5.2 - C	15d	28-Mar-18	20-Apr-18
S5.2-CN-1030	Wire Works - Segment 5.2 - D	15d	27-Apr-18	18-May-18
S5.2-CN-1040	Wire Works - Segment 5.2 - E	15d	28-May-18	18-Jun-18
S5.2-CN-1050	Wire Works - Segment 5.2 - F	15d	25-Jun-18	17-Jul-18
Communications		110d	21-Feb-18	31-Jul-18
S5.2-CM-1000	OPGW - Segment 5.2 - A	5d	21-Feb-18	28-Feb-18
S5.2-CM-1010	OPGW - Segment 5.2 - B	5d	21-Mar-18	28-Mar-18
S5.2-CM-1020	OPGW - Segment 5.2 - C	5d	20-Apr-18	27-Apr-18
S5.2-CM-1030	OPGW - Segment 5.2 - D	5d	18-May-18	28-May-18
S5.2-CM-1040	OPGW - Segment 5.2 - E	5d	18-Jun-18	25-Jun-18
S5.2-CM-1050	OPGW - Segment 5.2 - F	5d	17-Jul-18	24-Jul-18
Splices		105d	28-Feb-18	31-Jul-18
S5.2-CMS-1000	OPGW Splices - Segment 5.2 - A	5d	28-Feb-18	07-Mar-18
S5.2-CMS-1010	OPGW Splices - Segment 5.2 - B	5d	28-Mar-18	06-Apr-18
S5.2-CMS-1020	OPGW Splices - Segment 5.2 - C	5d	27-Apr-18	04-May-18
S5.2-CMS-1030	OPGW Splices - Segment 5.2 - D	5d	28-May-18	04-Jun-18
S5.2-CMS-1040	OPGW Splices - Segment 5.2 - E	5d	25-Jun-18	03-Jul-18
S5.2-CMS-1050	OPGW Splices - Segment 5.2 - F	5d	24-Jul-18	31-Jul-18
Segment 6 Wawa - Substation (20 km)		449d	04-Aug-16	28-May-18
Project Management		150d	18-Oct-17	28-May-18
Project Support		150d	18-Oct-17	28-May-18
S6-ENG-9000	Engineering Construction Support - Segment 6	115d	18-Oct-17	06-Apr-18
S6-ENG-9010	Engineering As-Builts - Segment 6	20d	06-Apr-18	04-May-18
S6-ENG-9020	Submit As-Builts - Segment 6	0d		04-May-18
S6-ENG-9030	Owner Review As-Builts - Segment 6	15d	04-May-18	28-May-18
Contractor Milestones Segment 6		414d	04-Aug-16	06-Apr-18
Start Dates		70d	08-Nov-17	21-Feb-18
S6-SD-MS-1010	Access Roads Start Date - Segment 6	0d	08-Nov-17	
S6-SD-MS-1020	Vegetation Management Start Date - Segment 6	0d	08-Nov-17	
S6-SD-MS-1030	Foundations Start Date - Segment 6	0d	16-Nov-17	
S6-SD-MS-1040	Structure Installation Start Date - Segment 6	0d	07-Dec-17	



Remaining Level of Effort
% Complete
Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

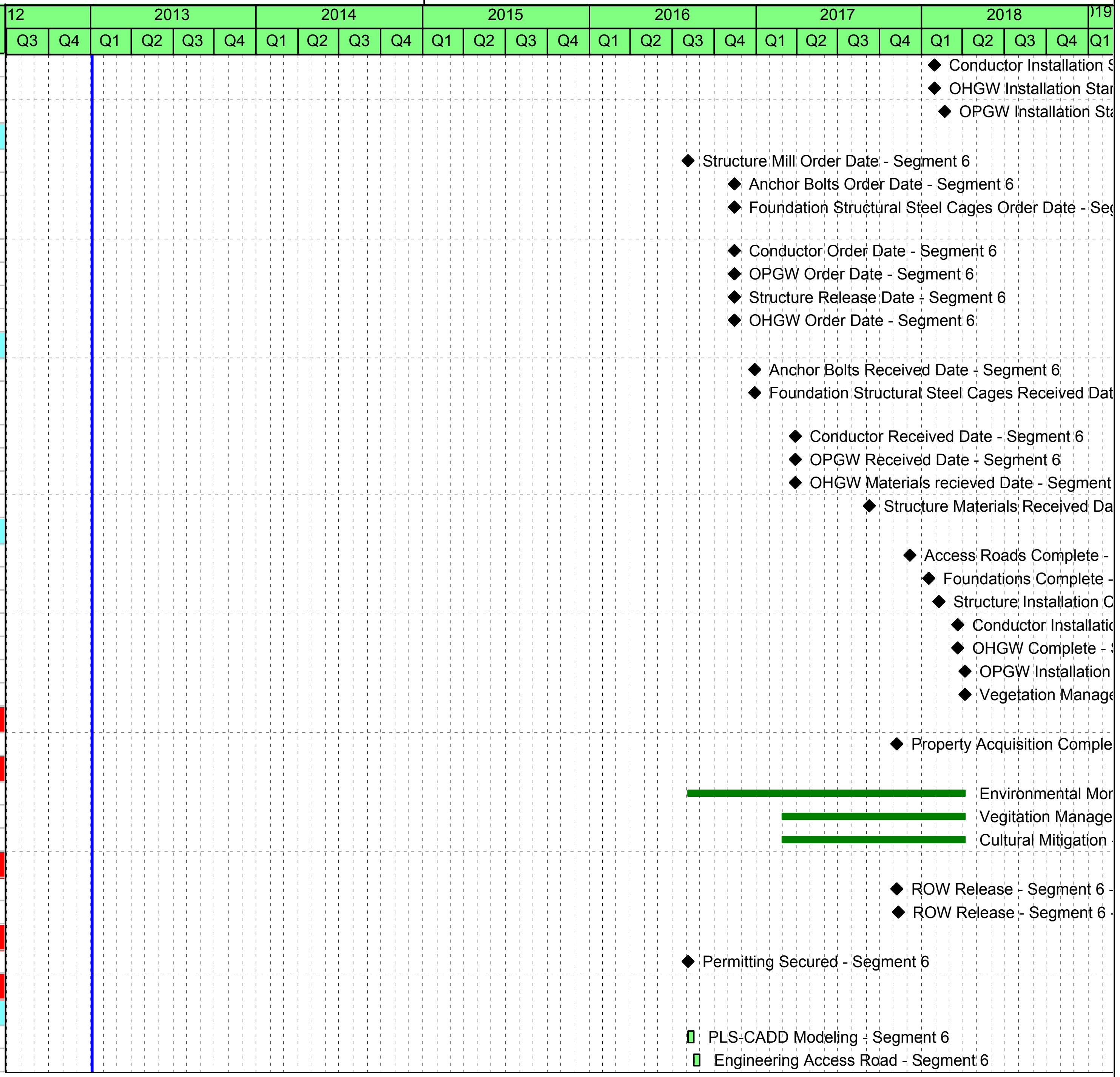
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
S6-SD-MS-1050	Conductor Installation Start Date - Segment 6	0d	30-Jan-18	
S6-SD-MS-1060	OHGW Installation Start Date - Segment 6	0d	30-Jan-18	
S6-SD-MS-1070	OPGW Installation Start Date - Segment 6	0d	21-Feb-18	
Order Dates		71d	04-Aug-16	16-Nov-16
S6-OD-MS-1010	Structure Mill Order Date - Segment 6	0d	04-Aug-16	
S6-OD-MS-1020	Anchor Bolts Order Date - Segment 6	0d	16-Nov-16	
S6-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 6	0d	16-Nov-16	
S6-OD-MS-1040	Conductor Order Date - Segment 6	0d	16-Nov-16	
S6-OD-MS-1050	OPGW Order Date - Segment 6	0d	16-Nov-16	
S6-OD-MS-1060	Structure Release Date - Segment 6	0d	16-Nov-16	
S6-OD-MS-1070	OHGW Order Date - Segment 6	0d	16-Nov-16	
Received Dates		170d	30-Dec-16	06-Sep-17
S6-RD-MS-1010	Anchor Bolts Received Date - Segment 6	0d		30-Dec-16
S6-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segment 6	0d		30-Dec-16
S6-RD-MS-1050	Conductor Received Date - Segment 6	0d		28-Mar-17
S6-RD-MS-1040	OPGW Received Date - Segment 6	0d		28-Mar-17
S6-RD-MS-1030	OHGW Materials recieved Date - Segment 6	0d		28-Mar-17
S6-RD-MS-1060	Structure Materials Received Date - Segment 6	0d		06-Sep-17
Completion Dates		80d	07-Dec-17	06-Apr-18
S6-CD-MS-1010	Access Roads Complete - Segment 6	0d		07-Dec-17
S6-CD-MS-1020	Foundations Complete - Segment 6	0d		16-Jan-18
S6-CD-MS-1030	Structure Installation Complete - Segment 6	0d		06-Feb-18
S6-CD-MS-1040	Conductor Installation Complete - Segment 6	0d		21-Mar-18
S6-CD-MS-1050	OHGW Complete - Segment 6	0d		21-Mar-18
S6-CD-MS-1060	OPGW Installation Complete - Segment 6	0d		06-Apr-18
S6-CD-MS-1070	Vegetation Management Complete - Segment 6	0d		06-Apr-18
Property		0d	08-Nov-17	08-Nov-17
S6-PRP-1000	Property Acquisition Complete - Segment 6	0d		08-Nov-17
Environmental		414d	04-Aug-16	06-Apr-18
S6-ENV-1000	Environmental Monitoring- Segment 6	414d	04-Aug-16	06-Apr-18
S6-ENV-1010	Vegitation Management - Segment 6	275d	27-Feb-17	06-Apr-18
S6-ENV-1020	Cultural Mitigation - Segment 6	275d	27-Feb-17	06-Apr-18
Right of Way		1d	08-Nov-17	09-Nov-17
S6-ROW-1000	ROW Release - Segment 6 - A	0d	08-Nov-17	
S6-ROW-1010	ROW Release - Segment 6 - B	0d	09-Nov-17	
Permitting		0d	04-Aug-16	04-Aug-16
S6-PMT-1000	Permitting Secured - Segment 6	0d		04-Aug-16
Transmission Lines		414d	04-Aug-16	06-Apr-18
Engineering-T-Line		71d	04-Aug-16	16-Nov-16
S6-ENG-1000	PLS-CADD Modeling - Segment 6	10d	04-Aug-16	18-Aug-16
S6-ENG-1010	Engineering Access Road - Segment 6	10d	18-Aug-16	01-Sep-16



🟩 Remaining Level of Effort ▬ % Complete

▬ Actual Level of Effort

🟦 Actual Work

🟩 Remaining Work

🟥 Critical Remaining Work

◆ ◆ Milestone

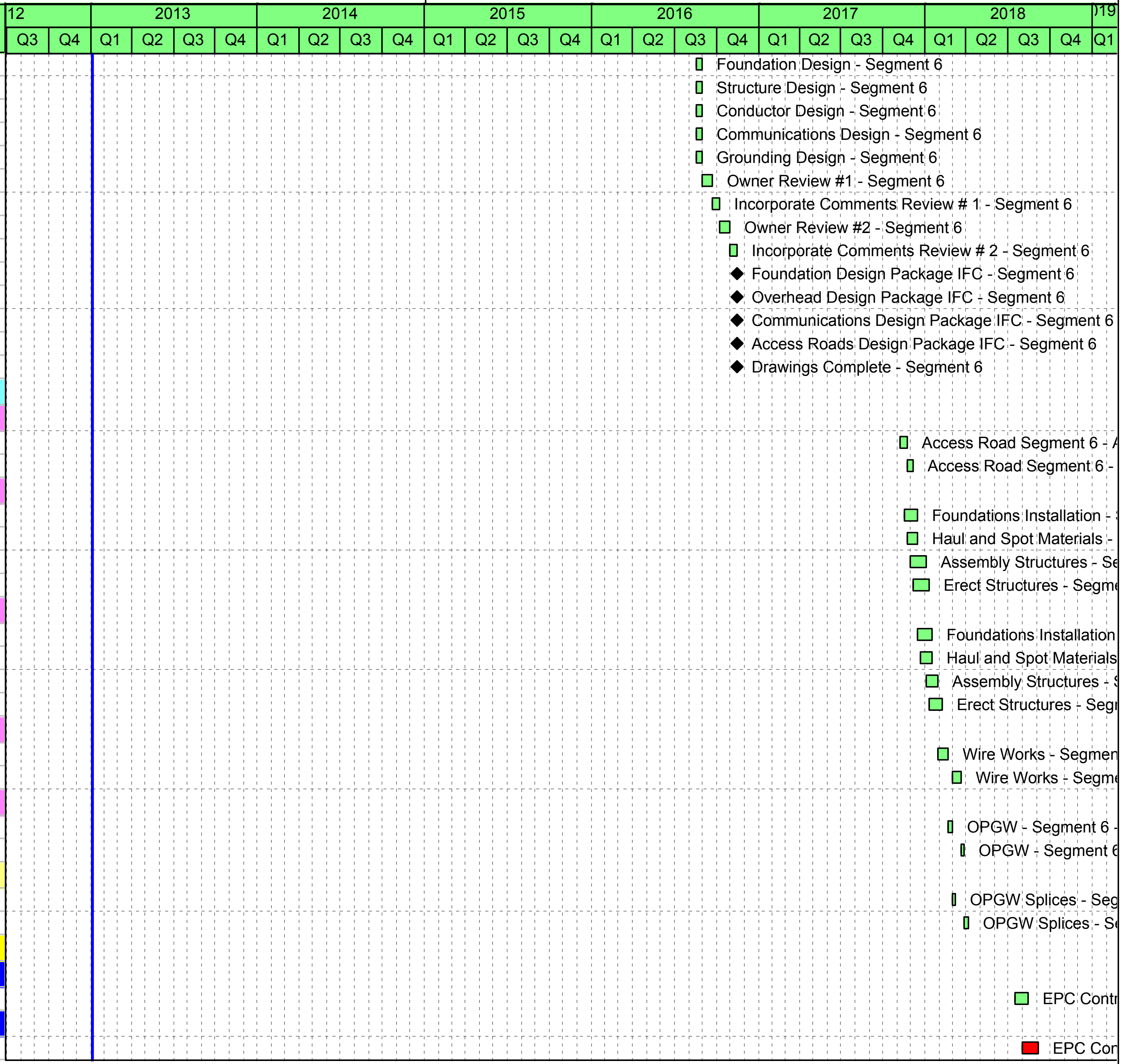
Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

Activity ID	Activity Name	Original Duration	Start	Finish
S6-ENG-1020	Foundation Design - Segment 6	10d	18-Aug-16	01-Sep-16
S6-ENG-1030	Structure Design - Segment 6	10d	18-Aug-16	01-Sep-16
S6-ENG-1040	Conductor Design - Segment 6	10d	18-Aug-16	01-Sep-16
S6-ENG-1050	Communications Design - Segment 6	10d	18-Aug-16	01-Sep-16
S6-ENG-1060	Grounding Design - Segment 6	10d	18-Aug-16	01-Sep-16
S6-ENG-1070	Owner Review #1 - Segment 6	15d	01-Sep-16	23-Sep-16
S6-ENG-1080	Incorporate Comments Review # 1 - Segment 6	10d	23-Sep-16	07-Oct-16
S6-ENG-1090	Owner Review #2 - Segment 6	15d	07-Oct-16	31-Oct-16
S6-ENG-1100	Incorporate Comments Review # 2 - Segment 6	10d	31-Oct-16	15-Nov-16
S6-ENG-1120	Foundation Design Package IFC - Segment 6	0d		15-Nov-16
S6-ENG-1130	Overhead Design Package IFC - Segment 6	0d		15-Nov-16
S6-ENG-1140	Communications Design Package IFC - Segment 6	0d		15-Nov-16
S6-ENG-1150	Access Roads Design Package IFC - Segment 6	0d		15-Nov-16
S6-ENG-1160	Drawings Complete - Segment 6	0d		16-Nov-16
Construction-T-Line		100d	08-Nov-17	06-Apr-18
Access Roads		20d	08-Nov-17	07-Dec-17
S6-AR-1000	Access Road Segment 6 - A	10d	08-Nov-17	23-Nov-17
S6-AR-1010	Access Road Segment 6 - B	10d	23-Nov-17	07-Dec-17
Section A		35d	16-Nov-17	09-Jan-18
S6-A-001	Foundations Installation - Segment 6 - A	20d	16-Nov-17	14-Dec-17
S6-A-002	Haul and Spot Materials - Segment 6 - A	15d	23-Nov-17	14-Dec-17
S6-A-003	Assembly Structures - Segment 6 - A	20d	30-Nov-17	02-Jan-18
S6-A-004	Erect Structures - Segment 6 - A	20d	07-Dec-17	09-Jan-18
Section B		35d	14-Dec-17	06-Feb-18
S6-B-001	Foundations Installation - Segment 6 - B	20d	14-Dec-17	16-Jan-18
S6-B-002	Haul and Spot Materials - Segment 6 - B	15d	21-Dec-17	16-Jan-18
S6-B-003	Assembly Structures - Segment 6 - B	20d	02-Jan-18	30-Jan-18
S6-B-004	Erect Structures - Segment 6 - B	20d	09-Jan-18	06-Feb-18
Wire Runs		35d	30-Jan-18	21-Mar-18
S6-CN-1000	Wire Works - Segment 6 - A	15d	30-Jan-18	21-Feb-18
S6-CN-1010	Wire Works - Segment 6 - B	15d	28-Feb-18	21-Mar-18
Communications		30d	21-Feb-18	06-Apr-18
S6-CM-1000	OPGW - Segment 6 - A	5d	21-Feb-18	28-Feb-18
S6-CM-1010	OPGW - Segment 6 - B	5d	21-Mar-18	28-Mar-18
Splices		25d	28-Feb-18	06-Apr-18
S6-CMS-1000	OPGW Splices - Segment 6 - A	5d	28-Feb-18	07-Mar-18
S6-CMS-1010	OPGW Splices - Segment 6 - B	5d	28-Mar-18	06-Apr-18
Testing & Commissioning		35d	17-Jul-18	06-Sep-18
Conductors		20d	17-Jul-18	15-Aug-18
CON-1000	EPC Contractor Testing - Conductors	20d	17-Jul-18	15-Aug-18
Communications		25d	31-Jul-18	06-Sep-18
COM-1000	EPC Contractor Testing - Communications	25d	31-Jul-18	06-Sep-18



🟩 Remaining Level of Effort ▬ % Complete
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

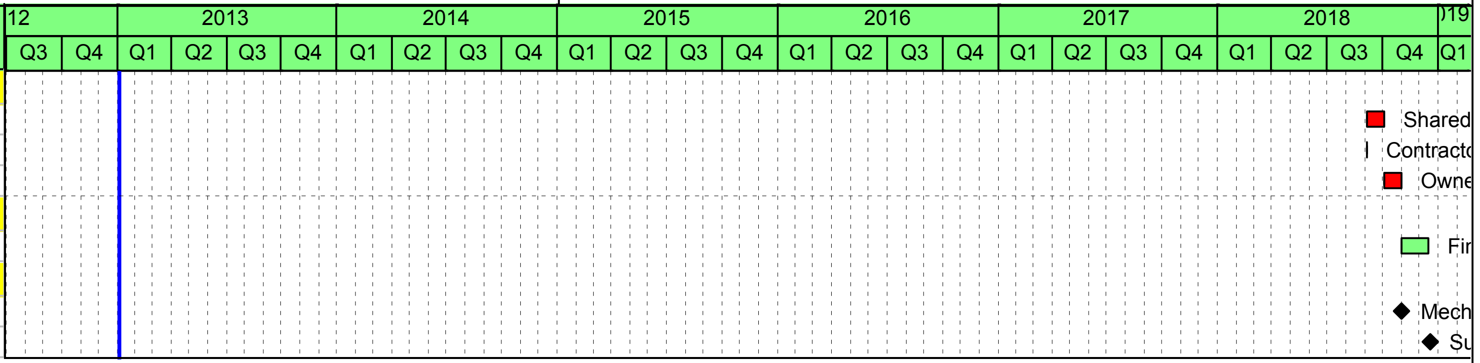
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 08-Dec-12

Activity ID	Activity Name	Original Duration	Start	Finish
Float		40d	06-Sep-18	02-Nov-18
SF-1000	Shared Float	20d	06-Sep-18	04-Oct-18
CF-1000	Contractor Float	0d	06-Sep-18	06-Sep-18
OF-1000	Owner Float	20d	04-Oct-18	02-Nov-18
Final End to End Testing		30d	02-Nov-18	17-Dec-18
FT-1000	Final End to End Testing Owner	30d	02-Nov-18	17-Dec-18
Completion Dates		32d	02-Nov-18	19-Dec-18
MC-1000	Mechanical Completion	0d		02-Nov-18
SC-1000	Substantial Completion	0d		19-Dec-18



▬ Remaining Level of Effort ▬ % Complete
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: All Activities

Layout: MAT WBS PMO Layout

TAB N-2-1

Development Phase – Schedule

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

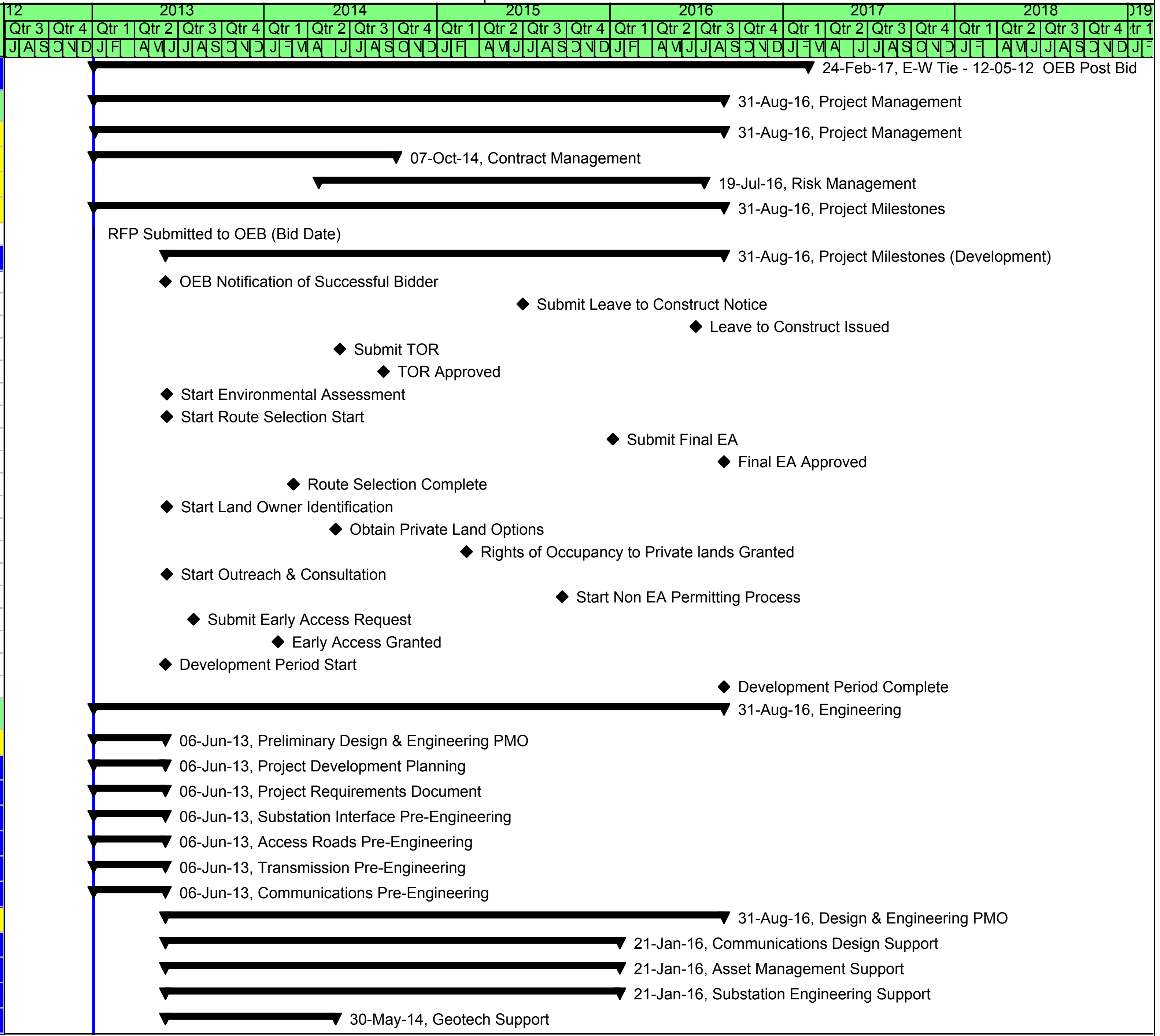
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
E-W Tie - 12-05-12 OEB Post Bid		04-Jan-13	24-Feb-17
Project Management		04-Jan-13	31-Aug-16
Project Management		07-Jan-13	31-Aug-16
Contract Management		04-Jan-13	07-Oct-14
Risk Management		25-Apr-14	19-Jul-16
Project Milestones		04-Jan-13	31-Aug-16
A2300	RFP Submitted to OEB (Bid Date)	04-Jan-13	04-Jan-13*
Project Milestones (Development)		06-Jun-13	31-Aug-16
A2310	OEB Notification of Successful Bidder		06-Jun-13
A2320	Submit Leave to Construct Notice	30-Jun-15	
A2330	Leave to Construct Issued		30-Jun-16
A2340	Submit TOR	09-Jun-14	
A2350	TOR Approved	09-Sep-14	
A2370	Start Environmental Assessment	07-Jun-13	
A2380	Start Route Selection Start	07-Jun-13	
A2390	Submit Final EA	07-Jan-16	
A2400	Final EA Approved		31-Aug-16
A2410	Route Selection Complete		04-Mar-14
A2420	Start Land Owner Identification	07-Jun-13	
A2431	Obtain Private Land Options		30-May-14
A2441	Rights of Occupancy to Private lands Granted		05-Mar-15
A2450	Start Outreach & Consultation	07-Jun-13	
A2460	Start Non EA Permitting Process	24-Sep-15	
A64160	Submit Early Access Request	02-Aug-13	
A64170	Early Access Granted		28-Jan-14
A64180	Development Period Start	06-Jun-13	
A64190	Development Period Complete		31-Aug-16
Engineering		04-Jan-13	31-Aug-16
Preliminary Design & Engineering PMO		04-Jan-13	06-Jun-13
Project Development Planning		04-Jan-13	06-Jun-13
Project Requirements Document		04-Jan-13	06-Jun-13
Substation Interface Pre-Engineering		04-Jan-13	06-Jun-13
Access Roads Pre-Engineering		04-Jan-13	06-Jun-13
Transmission Pre-Engineering		04-Jan-13	06-Jun-13
Communications Pre-Engineering		04-Jan-13	06-Jun-13
Design & Engineering PMO		06-Jun-13	31-Aug-16
Communications Design Support		06-Jun-13	21-Jan-16
Asset Management Support		06-Jun-13	21-Jan-16
Substation Engineering Support		06-Jun-13	21-Jan-16
Geotech Support		06-Jun-13	30-May-14



🟩 Remaining Level of Effort	▬ % Complete
▬ Actual Level of Effort	▼▬▼ Summary
🟦 Actual Work	
🟩 Remaining Work	
🟥 Critical Remaining Work	
◆ ◆ Milestone	

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Pre Construction.

Layout: MAT Development Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

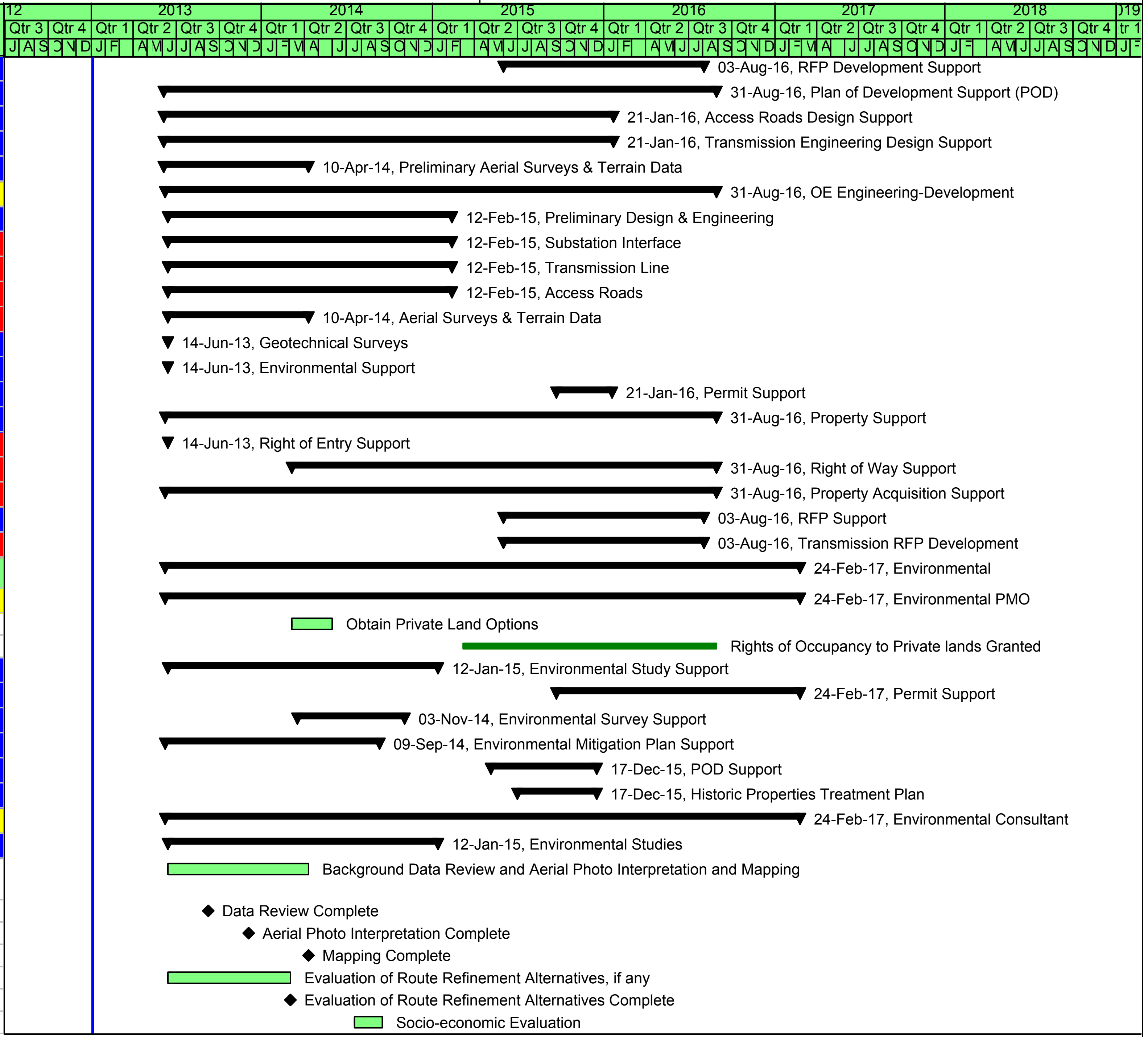
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
RFP Development Support		01-Jun-15	03-Aug-16
Plan of Development Support (POD)		06-Jun-13	31-Aug-16
Access Roads Design Support		06-Jun-13	21-Jan-16
Transmission Engineering Design Support		06-Jun-13	21-Jan-16
Preliminary Aerial Surveys & Terrain Data		06-Jun-13	10-Apr-14
OE Engineering-Development		07-Jun-13	31-Aug-16
Preliminary Design & Engineering		13-Jun-13	12-Feb-15
Substation Interface		13-Jun-13	12-Feb-15
Transmission Line		13-Jun-13	12-Feb-15
Access Roads		13-Jun-13	12-Feb-15
Aerial Surveys & Terrain Data		13-Jun-13	10-Apr-14
Geotechnical Surveys		13-Jun-13	14-Jun-13
Environmental Support		13-Jun-13	14-Jun-13
Permit Support		24-Sep-15	21-Jan-16
Property Support		07-Jun-13	31-Aug-16
Right of Entry Support		13-Jun-13	14-Jun-13
Right of Way Support		05-Mar-14	31-Aug-16
Property Acquisition Support		07-Jun-13	31-Aug-16
RFP Support		01-Jun-15	03-Aug-16
Transmission RFP Development		01-Jun-15	03-Aug-16
Environmental		07-Jun-13	24-Feb-17
Environmental PMO		07-Jun-13	24-Feb-17
A2430	Obtain Private Land Options	05-Mar-14	30-May-14
A2440	Rights of Occupancy to Private lands Granted	06-Mar-15	31-Aug-16
Environmental Study Support		13-Jun-13	12-Jan-15
Permit Support		24-Sep-15	24-Feb-17
Environmental Survey Support		19-Mar-14	03-Nov-14
Environmental Mitigation Plan Support		07-Jun-13	09-Sep-14
POD Support		04-May-15	17-Dec-15
Historic Properties Treatment Plan		30-Jun-15	17-Dec-15
Environmental Consultant		07-Jun-13	24-Feb-17
Environmental Studies		13-Jun-13	12-Jan-15
T2.01	Background Data Review and Aerial Photo Interpretation and Mapping	13-Jun-13	10-Apr-14
T2.01a	Data Review Complete		09-Sep-13
T2.01b	Aerial Photo Interpretation Complete		04-Dec-13
T2.01c	Mapping Complete		10-Apr-14
T2.02	Evaluation of Route Refinement Alternatives, if any	13-Jun-13	04-Mar-14
T2.02a	Evaluation of Route Refinement Alternatives Complete		04-Mar-14
T2.09	Socio-economic Evaluation	17-Jul-14	15-Sep-14



🟩 Remaining Level of Effort
▬ % Complete
▬ Actual Level of Effort
▼ Summary
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Pre Construction.

Layout: MAT Development Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
T2.09a	Socio-economic Evaluation Complete		15-Sep-14
T2.10	Timber Evaluation	17-Jul-14	15-Sep-14
T2.10a	Timber Evaluation Complete		15-Sep-14
T2.11	Hydrogeology	17-Jul-14	15-Sep-14
T2.11a	Hydrogeology Complete		15-Sep-14
T2.12	Preparation of Terrestrial Report	15-Sep-14	12-Jan-15
T2.12a	Preparation of Terrestrial Report Complete		12-Jan-15
T2.13	Preparation of Aquatic Technical Report	15-Sep-14	12-Jan-15
T2.13a	Preparation of Aquatic Technical Report Complete		12-Jan-15
Environmental Surveys		19-Mar-14	03-Nov-14
T2.03	Winter Wildlife Field Surveys (December-March)	06-Aug-14	03-Nov-14
T2.03a	Winter Wildlife Field Surveys Complete		03-Nov-14
T2.04	Spring Botanical and ELC (May-June)	11-Apr-14	18-Jun-14
T2.04a	Spring Botanical and ELC Complete		18-Jun-14
T2.05	Summer Botanical and ELC (August-September)	17-Jul-14	19-Sep-14
T2.05a	Summer Botanical and ELC Complete		19-Sep-14
T2.06	Fisheries and Aquatic Habitat Assessments (April-September)	19-Mar-14	17-Sep-14
T2.06a	Fisheries and Aquatic Habitat Assessments Complete		17-Sep-14
T2.08	Agriculture Field Inventory	17-Jul-14	15-Sep-14
T2.08a	Agriculture Field Inventory Complete		15-Sep-14
Environmental Impact Statement		07-Jun-13	26-Aug-16
T1.01	Consultation with MOE/Federal requirements/ Data Collection/Existing Environmental Conditions	07-Jun-13	04-Sep-13
T1.01a	Consultation Methodology Agreement		04-Sep-13
T1.02	Preparation of Consultation and Communications Plan	07-Jun-13*	04-Sep-13
T1.02a	Communications Plan Complete		04-Sep-13
T1.03	Agency and Stakeholders Mailings, Contact lists	07-Jun-13*	04-Sep-13
T1.03a	Agency and Stakeholders Contact lists Complete		04-Sep-13
T1.04	Newsletter Preparation and Mail out	07-Jun-13*	05-Dec-13
T1.05	Public Information Centres (4 total - two Thunder Bay, two in Wawa)	01-Aug-13	31-Mar-14
T1.05a	Public Information Centres two Thunder Bay (March & August 2013)	01-Aug-13*	29-Aug-13
T1.05a1	Thunder Bay PIC Complete		29-Aug-13
T1.05b	Public Information Centres two in Wawa (March & August 2013)	03-Mar-14*	31-Mar-14
T1.05b1	Wawa PIC Complete		31-Mar-14
T1.06	Preparation of Field study program (incl fly over to refine access/methods)	07-Jun-13	29-Nov-13
T1.06a	Field Study Program Complete		29-Nov-13
T1.07	Route Refinement Evaluation	07-Jun-13	29-Nov-13
T1.07a	Route Refinement Complete		29-Nov-13
T1.08	Agency and Interest Group Meetings/Workshop	07-Jun-13	04-Sep-13

🟩 Remaining Level of Effort	▬ % Complete
🟦 Actual Level of Effort	▼▬▼ Summary
🟦 Actual Work	
🟩 Remaining Work	
🟥 Critical Remaining Work	
◆ ◆ Milestone	

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Pre Construction.

Layout: MAT Development Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

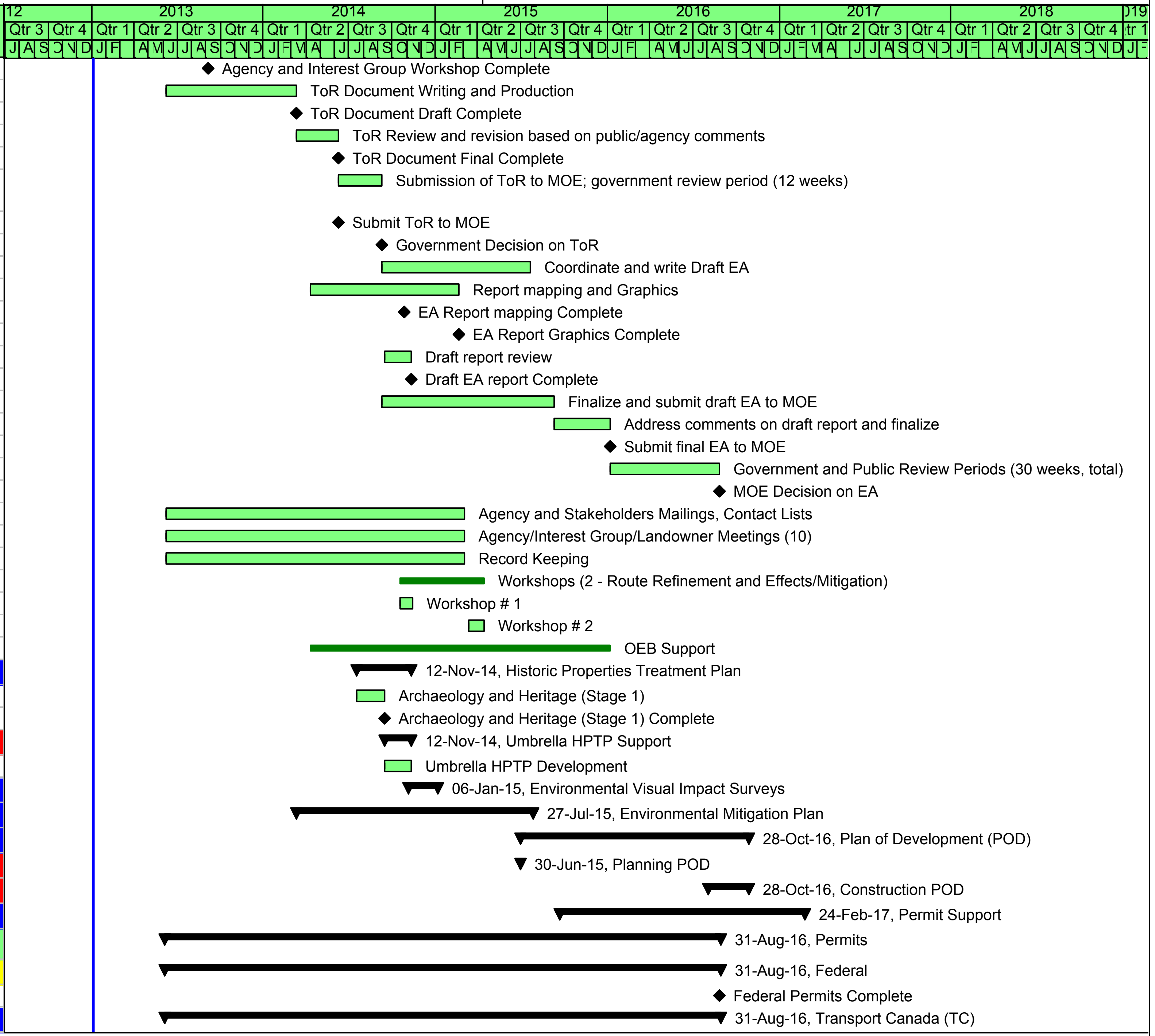
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
T1.08a	Agency and Interest Group Workshop Complete		04-Sep-13
T1.09	ToR Document Writing and Production	07-Jun-13	12-Mar-14
T1.09a	ToR Document Draft Complete		12-Mar-14
T1.10	ToR Review and revision based on public/agency comme...	12-Mar-14	09-Jun-14
T1.10b	ToR Document Final Complete		09-Jun-14
T1.11	Submission of ToR to MOE; government review period (12 weeks)	09-Jun-14	09-Sep-14
T1.11a	Submit ToR to MOE		09-Jun-14
T1.12	Government Decision on ToR	09-Sep-14	
T2.14	Coordinate and write Draft EA	09-Sep-14	22-Jul-15
T2.15	Report mapping and Graphics	11-Apr-14	20-Feb-15
T2.15a	EA Report mapping Complete		27-Oct-14
T2.15b	EA Report Graphics Complete		20-Feb-15
T2.16	Draft report review	15-Sep-14	12-Nov-14
T2.16a	Draft EA report Complete		12-Nov-14
T2.17	Finalize and submit draft EA to MOE	09-Sep-14	10-Sep-15
T2.18	Address comments on draft report and finalize	10-Sep-15	07-Jan-16
T2.19	Submit final EA to MOE		07-Jan-16
T2.20	Government and Public Review Periods (30 weeks, total)	07-Jan-16	26-Aug-16
T2.21	MOE Decision on EA		26-Aug-16
T3.01	Agency and Stakeholders Mailings, Contact Lists	07-Jun-13	05-Mar-15
T3.04	Agency/Interest Group/Landowner Meetings (10)	07-Jun-13	04-Mar-15
T3.05	Record Keeping	07-Jun-13	04-Mar-15
T3.07	Workshops (2 - Route Refinement and Effects/Mitigation)	17-Oct-14	13-Apr-15
T3.07a	Workshop # 1	17-Oct-14	14-Nov-14
T3.07b	Workshop # 2	13-Mar-15	13-Apr-15
T4.01	OEB Support	11-Apr-14	07-Jan-16
Historic Properties Treatment Plan		17-Jul-14	12-Nov-14
T2.07	Archaeology and Heritage (Stage 1)	17-Jul-14	15-Sep-14
T2.07a	Archaeology and Heritage (Stage 1) Complete		15-Sep-14
Umbrella HPTP Support		15-Sep-14	12-Nov-14
A1500	Umbrella HPTP Development	15-Sep-14	12-Nov-14
Environmental Visual Impact Surveys		05-Nov-14	06-Jan-15
Environmental Mitigation Plan		12-Mar-14	27-Jul-15
Plan of Development (POD)		30-Jun-15	28-Oct-16
Planning POD		30-Jun-15	30-Jun-15
Construction POD		03-Aug-16	28-Oct-16
Permit Support		24-Sep-15	24-Feb-17
Permits		06-Jun-13	31-Aug-16
Federal		06-Jun-13	31-Aug-16
A63020	Federal Permits Complete		26-Aug-16
Transport Canada (TC)		06-Jun-13	31-Aug-16



🟩 Remaining Level of Effort
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ Milestone
▬ % Complete
▼ Summary

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Pre Construction.

Layout: MAT Development Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

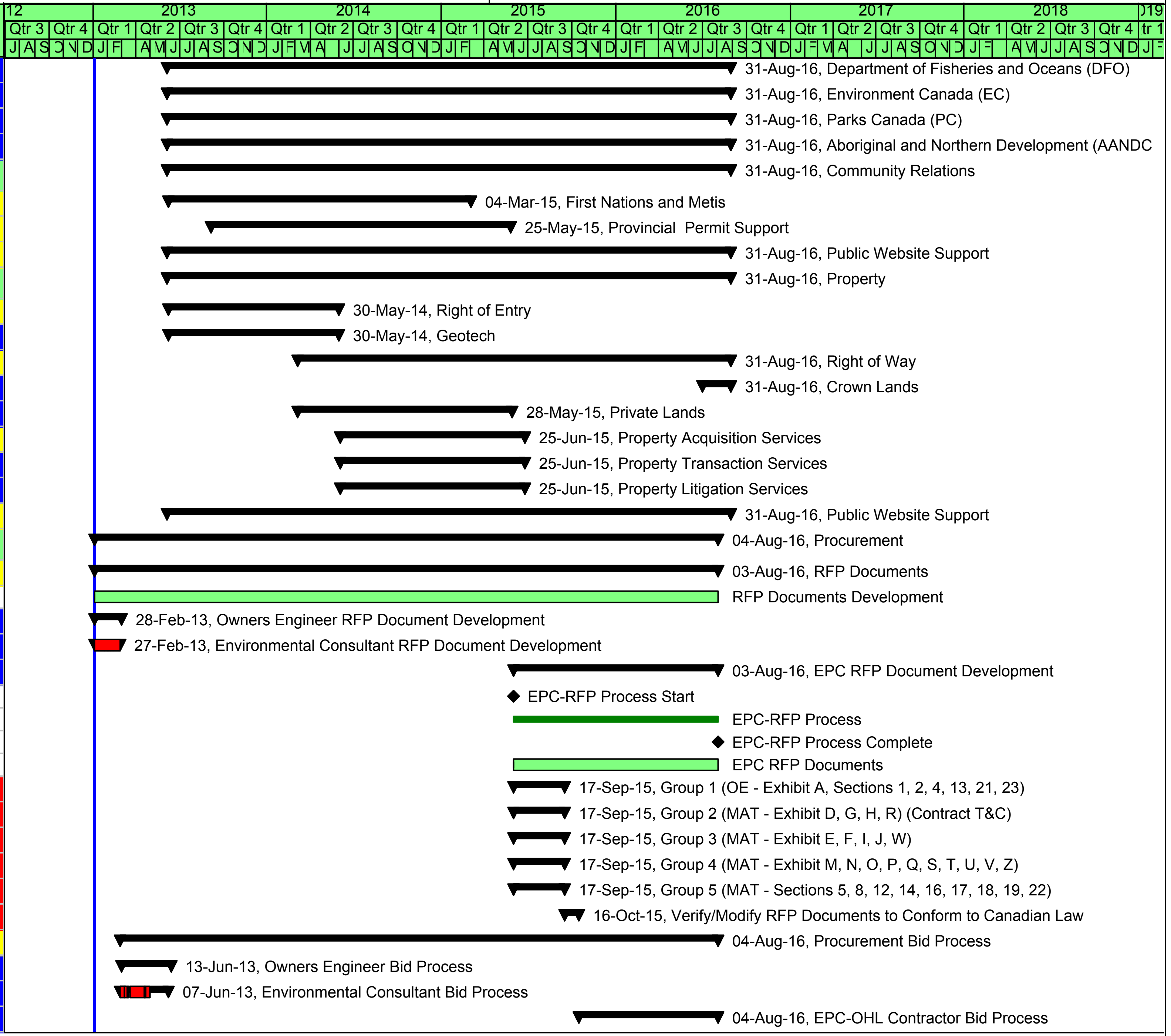
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
Department of Fisheries and Oceans (DFO)		06-Jun-13	31-Aug-16
Environment Canada (EC)		06-Jun-13	31-Aug-16
Parks Canada (PC)		06-Jun-13	31-Aug-16
Aboriginal and Northern Development (AANDC		06-Jun-13	31-Aug-16
Community Relations		06-Jun-13	31-Aug-16
First Nations and Metis		07-Jun-13	04-Mar-15
Provincial Permit Support		04-Sep-13	25-May-15
Public Website Support		06-Jun-13	31-Aug-16
Property		06-Jun-13	31-Aug-16
Right of Entry		07-Jun-13	30-May-14
Geotech		07-Jun-13	30-May-14
Right of Way		05-Mar-14	31-Aug-16
Crown Lands		30-Jun-16	31-Aug-16
Private Lands		05-Mar-14	28-May-15
Property Acquisition Services		02-Jun-14	25-Jun-15
Property Transaction Services		02-Jun-14	25-Jun-15
Property Litigation Services		02-Jun-14	25-Jun-15
Public Website Support		06-Jun-13	31-Aug-16
Procurement		04-Jan-13	04-Aug-16
RFP Documents		04-Jan-13	03-Aug-16
A64120	RFP Documents Development	04-Jan-13	03-Aug-16
Owners Engineer RFP Document Development		04-Jan-13	28-Feb-13
Environmental Consultant RFP Document Development		04-Jan-13	27-Feb-13
EPC RFP Document Development		01-Jun-15	03-Aug-16
EPC-RFP-0000	EPC-RFP Process Start	01-Jun-15	
EPC-RFP-1000	EPC-RFP Process	01-Jun-15	03-Aug-16
EPC-RFP-2000	EPC-RFP Process Complete		03-Aug-16
EPC-RFP-WBS	EPC RFP Documents	01-Jun-15	03-Aug-16
Group 1 (OE - Exhibit A, Sections 1, 2, 4, 13, 21, 23)		01-Jun-15	17-Sep-15
Group 2 (MAT - Exhibit D, G, H, R) (Contract T&C)		01-Jun-15	17-Sep-15
Group 3 (MAT - Exhibit E, F, I, J, W)		01-Jun-15	17-Sep-15
Group 4 (MAT - Exhibit M, N, O, P, Q, S, T, U, V, Z)		01-Jun-15	17-Sep-15
Group 5 (MAT - Sections 5, 8, 12, 14, 16, 17, 18, 19, 22)		01-Jun-15	17-Sep-15
Verify/Modify RFP Documents to Conform to Canadian Law		17-Sep-15	16-Oct-15
Procurement Bid Process		27-Feb-13	04-Aug-16
Owners Engineer Bid Process		28-Feb-13	13-Jun-13
Environmental Consultant Bid Process		27-Feb-13	07-Jun-13
EPC-OHL Contractor Bid Process		16-Oct-15	04-Aug-16



🟩 Remaining Level of Effort
▬ % Complete
🟦 Actual Level of Effort
▼ Summary
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Pre Construction.

Layout: MAT Development Layout Rollup

TAB N-2-2

Development Phase – Milestones

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

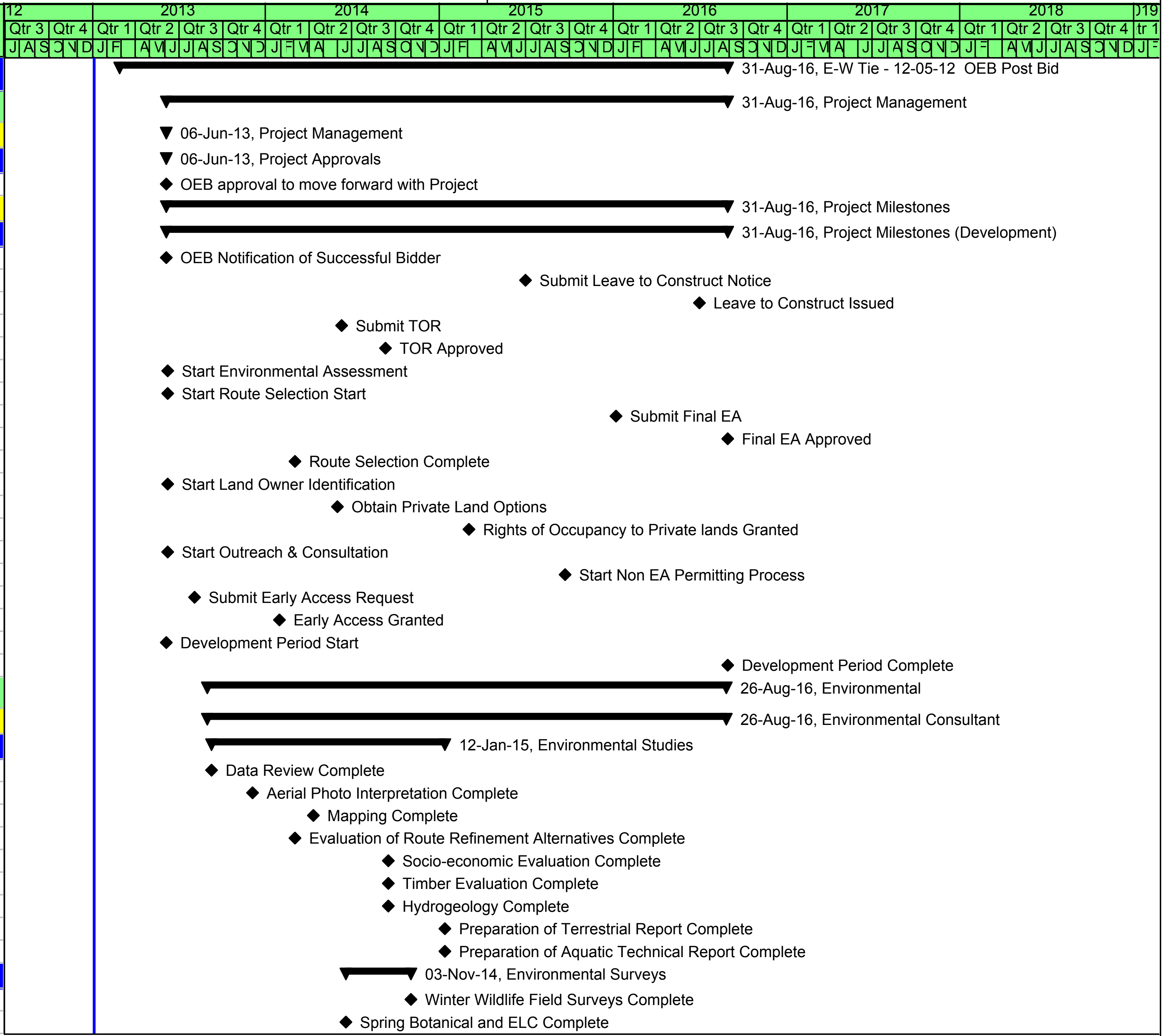
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
E-W Tie - 12-05-12 OEB Post Bid		27-Feb-13	31-Aug-16
Project Management		06-Jun-13	31-Aug-16
Project Management		06-Jun-13	06-Jun-13
Project Approvals		06-Jun-13	06-Jun-13
A1030	OEB approval to move forward with Project	06-Jun-13	
Project Milestones		06-Jun-13	31-Aug-16
Project Milestones (Development)		06-Jun-13	31-Aug-16
A2310	OEB Notification of Successful Bidder		06-Jun-13
A2320	Submit Leave to Construct Notice	30-Jun-15	
A2330	Leave to Construct Issued		30-Jun-16
A2340	Submit TOR	09-Jun-14	
A2350	TOR Approved	09-Sep-14	
A2370	Start Environmental Assessment	07-Jun-13	
A2380	Start Route Selection Start	07-Jun-13	
A2390	Submit Final EA	07-Jan-16	
A2400	Final EA Approved		31-Aug-16
A2410	Route Selection Complete		04-Mar-14
A2420	Start Land Owner Identification	07-Jun-13	
A2431	Obtain Private Land Options		30-May-14
A2441	Rights of Occupancy to Private lands Granted		05-Mar-15
A2450	Start Outreach & Consultation	07-Jun-13	
A2460	Start Non EA Permitting Process	24-Sep-15	
A64160	Submit Early Access Request	02-Aug-13	
A64170	Early Access Granted		28-Jan-14
A64180	Development Period Start	06-Jun-13	
A64190	Development Period Complete		31-Aug-16
Environmental		29-Aug-13	26-Aug-16
Environmental Consultant		29-Aug-13	26-Aug-16
Environmental Studies		09-Sep-13	12-Jan-15
T2.01a	Data Review Complete		09-Sep-13
T2.01b	Aerial Photo Interpretation Complete		04-Dec-13
T2.01c	Mapping Complete		10-Apr-14
T2.02a	Evaluation of Route Refinement Alternatives Complete		04-Mar-14
T2.09a	Socio-economic Evaluation Complete		15-Sep-14
T2.10a	Timber Evaluation Complete		15-Sep-14
T2.11a	Hydrogeology Complete		15-Sep-14
T2.12a	Preparation of Terrestrial Report Complete		12-Jan-15
T2.13a	Preparation of Aquatic Technical Report Complete		12-Jan-15
Environmental Surveys		18-Jun-14	03-Nov-14
T2.03a	Winter Wildlife Field Surveys Complete		03-Nov-14
T2.04a	Spring Botanical and ELC Complete		18-Jun-14



🟩 Remaining Level of Effort
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone
▬ % Complete
▼ Summary

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Pre Construction, Milestone.

Layout: MAT Development Milestone Layout

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

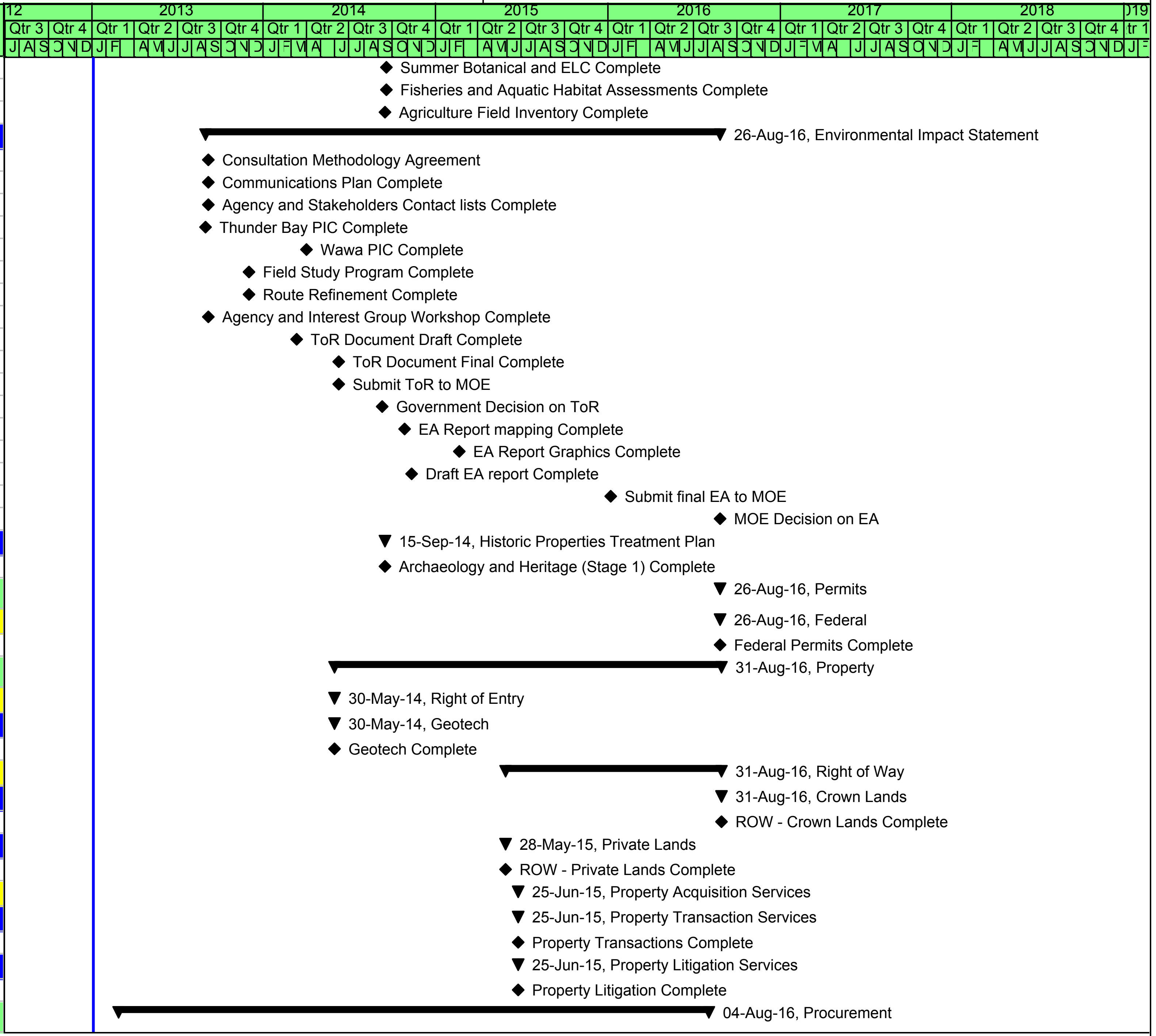
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
T2.05a	Summer Botanical and ELC Complete		19-Sep-14
T2.06a	Fisheries and Aquatic Habitat Assessments Complete		17-Sep-14
T2.08a	Agriculture Field Inventory Complete		15-Sep-14
Environmental Impact Statement		29-Aug-13	26-Aug-16
T1.01a	Consultation Methodology Agreement		04-Sep-13
T1.02a	Communications Plan Complete		04-Sep-13
T1.03a	Agency and Stakeholders Contact lists Complete		04-Sep-13
T1.05a1	Thunder Bay PIC Complete		29-Aug-13
T1.05b1	Wawa PIC Complete		31-Mar-14
T1.06a	Field Study Program Complete		29-Nov-13
T1.07a	Route Refinement Complete		29-Nov-13
T1.08a	Agency and Interest Group Workshop Complete		04-Sep-13
T1.09a	ToR Document Draft Complete		12-Mar-14
T1.10b	ToR Document Final Complete		09-Jun-14
T1.11a	Submit ToR to MOE		09-Jun-14
T1.12	Government Decision on ToR	09-Sep-14	
T2.15a	EA Report mapping Complete		27-Oct-14
T2.15b	EA Report Graphics Complete		20-Feb-15
T2.16a	Draft EA report Complete		12-Nov-14
T2.19	Submit final EA to MOE		07-Jan-16
T2.21	MOE Decision on EA		26-Aug-16
Historic Properties Treatment Plan		15-Sep-14	15-Sep-14
T2.07a	Archaeology and Heritage (Stage 1) Complete		15-Sep-14
Permits		26-Aug-16	26-Aug-16
Federal		26-Aug-16	26-Aug-16
A63020	Federal Permits Complete		26-Aug-16
Property		30-May-14	31-Aug-16
Right of Entry		30-May-14	30-May-14
Geotech		30-May-14	30-May-14
A63050	Geotech Complete		30-May-14
Right of Way		28-May-15	31-Aug-16
Crown Lands		31-Aug-16	31-Aug-16
A63060	ROW - Crown Lands Complete		31-Aug-16
Private Lands		28-May-15	28-May-15
A63070	ROW - Private Lands Complete		28-May-15
Property Acquisition Services		25-Jun-15	25-Jun-15
Property Transaction Services		25-Jun-15	25-Jun-15
A63080	Property Transactions Complete		25-Jun-15
Property Litigation Services		25-Jun-15	25-Jun-15
A63090	Property Litigation Complete		25-Jun-15
Procurement		27-Feb-13	04-Aug-16



🟩 Remaining Level of Effort	▬ % Complete
▬ Actual Level of Effort	▼▬▼ Summary
🟦 Actual Work	
🟩 Remaining Work	
🟥 Critical Remaining Work	
◆ Milestone	

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Pre Construction, Milestone.

Layout: MAT Development Milestone Layout

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

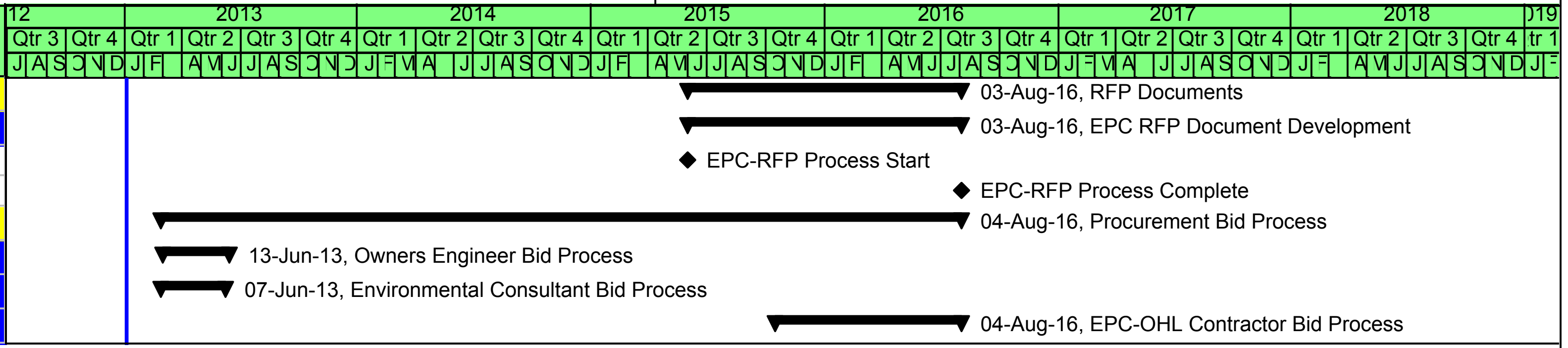
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
RFP Documents		01-Jun-15	03-Aug-16
EPC RFP Document Development		01-Jun-15	03-Aug-16
EPC-RFP-0000	EPC-RFP Process Start	01-Jun-15	
EPC-RFP-2000	EPC-RFP Process Complete		03-Aug-16
Procurement Bid Process		27-Feb-13	04-Aug-16
Owners Engineer Bid Process		28-Feb-13	13-Jun-13
Environmental Consultant Bid Process		27-Feb-13	07-Jun-13
EPC-OHL Contractor Bid Process		16-Oct-15	04-Aug-16



🟩 Remaining Level of Effort
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone
▬ % Complete
▼▬▼ Summary

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Pre Construction, Milestone.

Layout: MAT Development Milestone Layout

TAB N-2-3

Development Phase – Schedule Risks and Mitigation Strategy

Table N-1, below, summarizes the major Development Phase schedule risks, the associated mitigation strategy, the likelihood of occurrence and the assessed level of impact.

Table N-1

Schedule Exposure					
Category	**Issue/Description**	**Item**	**Mitigation Strategy**	**Likelihood**	**Severity**
Environmental Assessment	Unanticipated study requirements	1	Use of experienced Ontario consultants (Stantec or comparable equivalent) to undertake all studies; early access application to OEB if needed	Somewhat Likely	Moderate
Design/ Engineering/ Management	Accuracy of baseline assumptions for route, line length, general scope inclusions and project plan changes	2	Develop project plan and work with all stakeholder parties to define and resolve issues as they arise	Somewhat Likely	Minor
Option Agreements for Land and Access Rights	Unanticipated problems in securing options for land and access rights	3	Early and proactive outreach with all private, public, and Crown entities from which land rights will be needed. Extensive work already completed by the Applicant in connection with this Application.	Not Likely	Minor

Schedule Exposure

Category	Issue/Description	Item	Mitigation Strategy	Likelihood	Severity
Stakeholder Consultations	Unanticipated challenges in addressing and mitigating stakeholder concerns	4	Early and proactive outreach involving public meetings, mass mailings, a website, newspaper postings and similar outreach strategies.	Not Likely	Minor
Administrative/ Regulatory	Untimely decisions or actions by regulatory agencies and Hydro One	5	Early and proactive outreach supported by consultants and legal advisors, facilitated by the submission of timely and complete materials	Somewhat Likely	Moderate
Option Agreements for Mining & Timber Rights	Unanticipated problems in securing options for mining & timber rights	6	Early and proactive outreach with entities that have mining and timber rights on Crown lands, supported by experienced counsel (FMC)	Not Likely	Minor
First Nation Participation	Unanticipated problems in negotiating satisfactory participation agreements	7	Early and proactive outreach assisted by John Beaucage in which multiple options are made available to First Nation	Somewhat Likely	Moderate
Terms of Reference (ToR) for Environmental Assessment	Unanticipated delays in preparing and securing approvals for Terms of Reference (ToR)	8	Use of experienced Ontario consultants (Stantec or comparable equivalent) to prepare a complete ToR application; close coordination with MOE	Not Likely	Minor

Schedule Exposure					
Category	**Issue/Description**	**Item**	**Mitigation Strategy**	**Likelihood**	**Severity**
Aboriginal Consultations	Unanticipated challenges in negotiating impact benefit agreements with First Nation and Métis peoples	9	Early and proactive outreach assisted by John Beaucage that involves coordination and a MOU with the OPA	Somewhat Likely	Moderate
Project Need	Unanticipated requirements to support OPA in the preparation of a benefit/cost analysis	10	Close coordination with OPA and the use of advisors experienced in such matters (E3 or Brattle)	Not Likely	Minor
Route Selection	Unanticipated challenges in selecting a final route	11	Input from stakeholder and First Nation and Métis consultation processes to identify route refinements in conjunction with design and engineering input; substantial work already completed by Applicant	Not Likely	Minor

TAB N-3-1

Construction Phase – Schedule

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

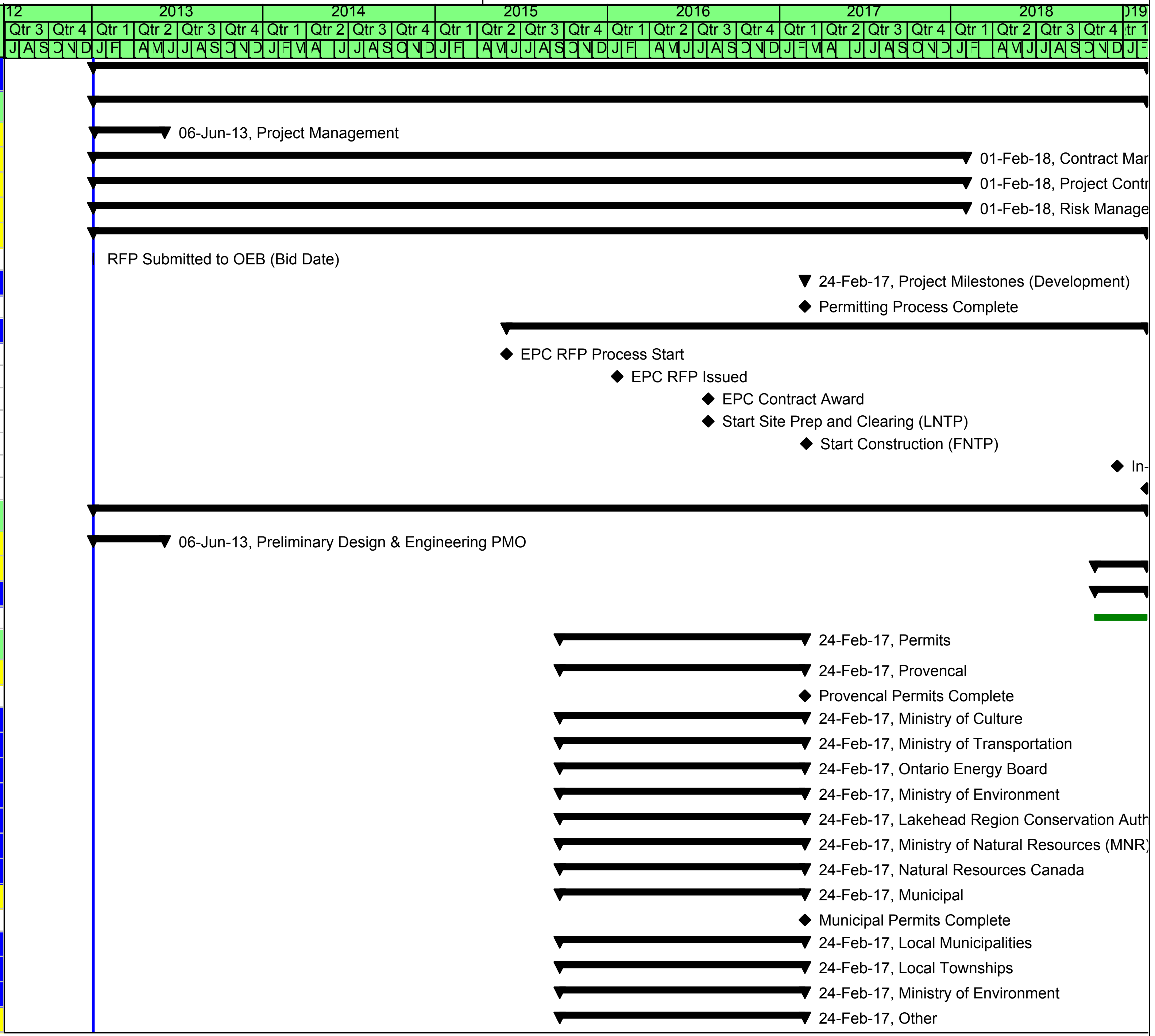
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
E-W Tie - 12-05-12 OEB Post Bid		04-Jan-13	21-Feb-19
Project Management		04-Jan-13	20-Feb-19
Project Management		07-Jan-13	06-Jun-13
Contract Management		04-Jan-13	01-Feb-18
Project Controls		04-Jan-13	01-Feb-18
Risk Management		04-Jan-13	01-Feb-18
Project Milestones		04-Jan-13	20-Feb-19
A2300	RFP Submitted to OEB (Bid Date)	04-Jan-13	04-Jan-13*
Project Milestones (Development)		24-Feb-17	24-Feb-17
A2470	Permitting Process Complete		24-Feb-17
Project Milestones (Construction)		01-Jun-15	20-Feb-19
A2480	EPC RFP Process Start	01-Jun-15	
A2490	EPC RFP Issued	21-Jan-16	
A2500	EPC Contract Award		03-Aug-16
A2510	Start Site Prep and Clearing (LNTP)	04-Aug-16	
A2520	Start Construction (FNTP)	27-Feb-17	
A2530	In-Service Date		19-Dec-18
A2540	Project Completion		20-Feb-19
Engineering		04-Jan-13	20-Feb-19
Preliminary Design & Engineering PMO		04-Jan-13	06-Jun-13
Design & Engineering PMO		02-Nov-18	20-Feb-19
Close Out Support		02-Nov-18	20-Feb-19
A1450	Project Close Out Support	02-Nov-18	20-Feb-19
Permits		24-Sep-15	24-Feb-17
Provencal		24-Sep-15	24-Feb-17
A63010	Provencal Permits Complete		24-Feb-17
Ministry of Culture		24-Sep-15	24-Feb-17
Ministry of Transportation		24-Sep-15	24-Feb-17
Ontario Energy Board		24-Sep-15	24-Feb-17
Ministry of Environment		24-Sep-15	24-Feb-17
Lakehead Region Conservation Authority (LRCA)		24-Sep-15	24-Feb-17
Ministry of Natural Resources (MNR)		24-Sep-15	24-Feb-17
Natural Resources Canada		24-Sep-15	24-Feb-17
Municipal		24-Sep-15	24-Feb-17
A63030	Municipal Permits Complete		24-Feb-17
Local Municipalities		24-Sep-15	24-Feb-17
Local Townships		24-Sep-15	24-Feb-17
Ministry of Environment		24-Sep-15	24-Feb-17
Other		24-Sep-15	24-Feb-17



▬ Remaining Level of Effort
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone
▬ % Complete
▼▬▼ Summary

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

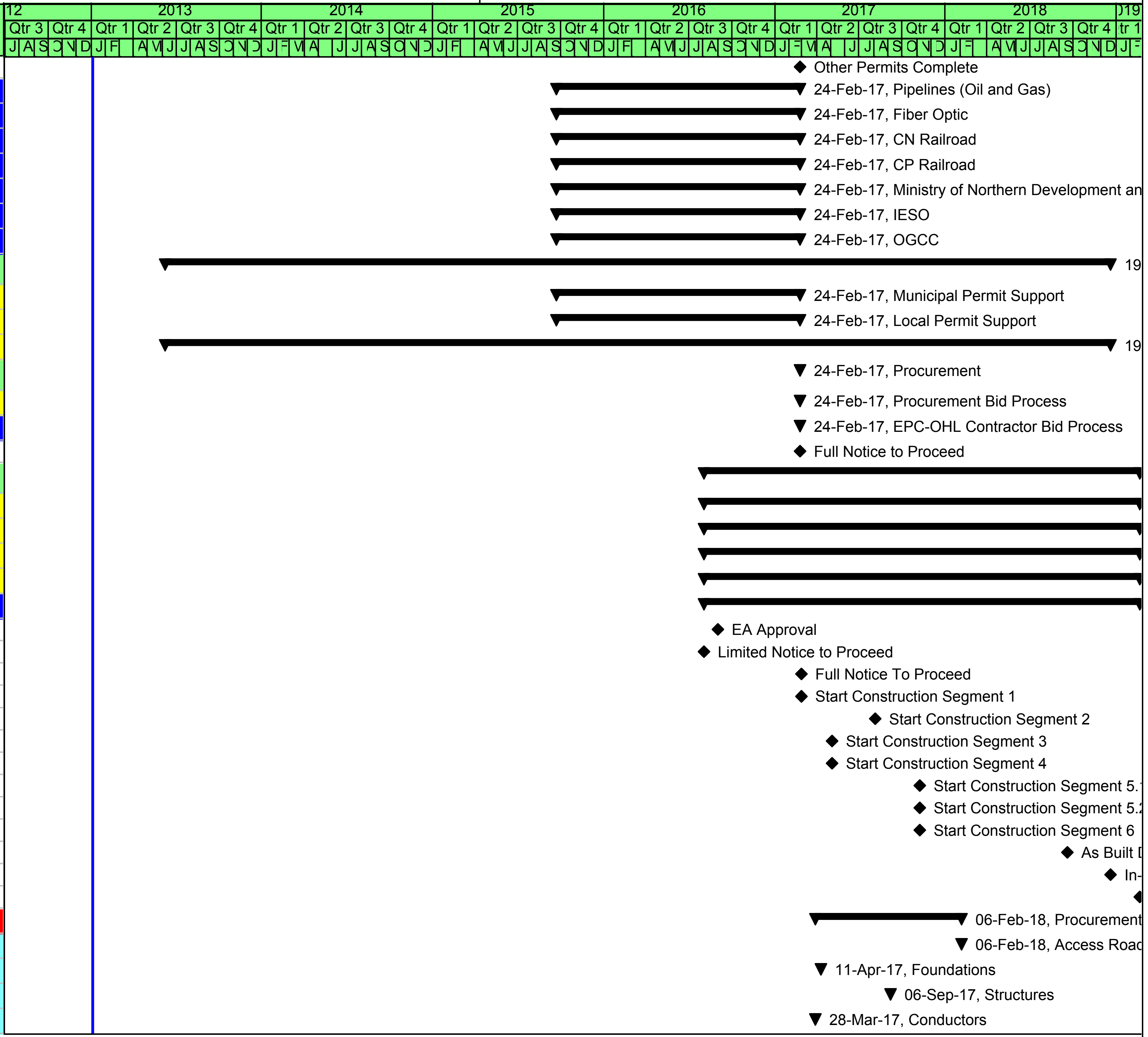
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
A63040	Other Permits Complete		24-Feb-17
Pipelines (Oil and Gas)		24-Sep-15	24-Feb-17
Fiber Optic		24-Sep-15	24-Feb-17
CN Railroad		24-Sep-15	24-Feb-17
CP Railroad		24-Sep-15	24-Feb-17
Ministry of Northern Development and Mines (MNDM)		24-Sep-15	24-Feb-17
IESO		24-Sep-15	24-Feb-17
OGCC		24-Sep-15	24-Feb-17
Community Relations		07-Jun-13	19-Dec-18
Municipal Permit Support		24-Sep-15	24-Feb-17
Local Permit Support		24-Sep-15	24-Feb-17
Property ROE ROW Support		07-Jun-13	19-Dec-18
Procurement		24-Feb-17	24-Feb-17
Procurement Bid Process		24-Feb-17	24-Feb-17
EPC-OHL Contractor Bid Process		24-Feb-17	24-Feb-17
EPC-PR-1550	Full Notice to Proceed		24-Feb-17
EPC Construction		03-Aug-16	21-Feb-19
Project Management Oversight		03-Aug-16	21-Feb-19
Environmental Compliance		04-Aug-16	20-Feb-19
Permitting Compliance		04-Aug-16	21-Feb-19
Transmission Lines Construction		04-Aug-16	20-Feb-19
Project Milestones		04-Aug-16	20-Feb-19
PRJ-MS-0000	EA Approval	01-Sep-16	
PRJ-MS-1000	Limited Notice to Proceed	04-Aug-16	
PRJ-MS-1010	Full Notice To Proceed	27-Feb-17	
PRJ-MS-1020	Start Construction Segment 1	27-Feb-17	
PRJ-MS-1030	Start Construction Segment 2	04-Aug-17	
PRJ-MS-1040	Start Construction Segment 3	03-May-17	
PRJ-MS-1050	Start Construction Segment 4	03-May-17	
PRJ-MS-1060	Start Construction Segment 5.1	08-Nov-17	
PRJ-MS-1070	Start Construction Segment 5.2	08-Nov-17	
PRJ-MS-1080	Start Construction Segment 6	08-Nov-17	
PRJ-MS-1090	As Built Documents Complete		20-Sep-18
PRJ-MS-1100	In-Service Date		19-Dec-18
PRJ-MS-1110	Final Project Completion Date		20-Feb-19
Procurement Milestones		28-Mar-17	06-Feb-18
Access Roads		06-Feb-18	06-Feb-18
Foundations		11-Apr-17	11-Apr-17
Structures		06-Sep-17	06-Sep-17
Conductors		28-Mar-17	28-Mar-17



Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
◆ Milestone
% Complete
Summary

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

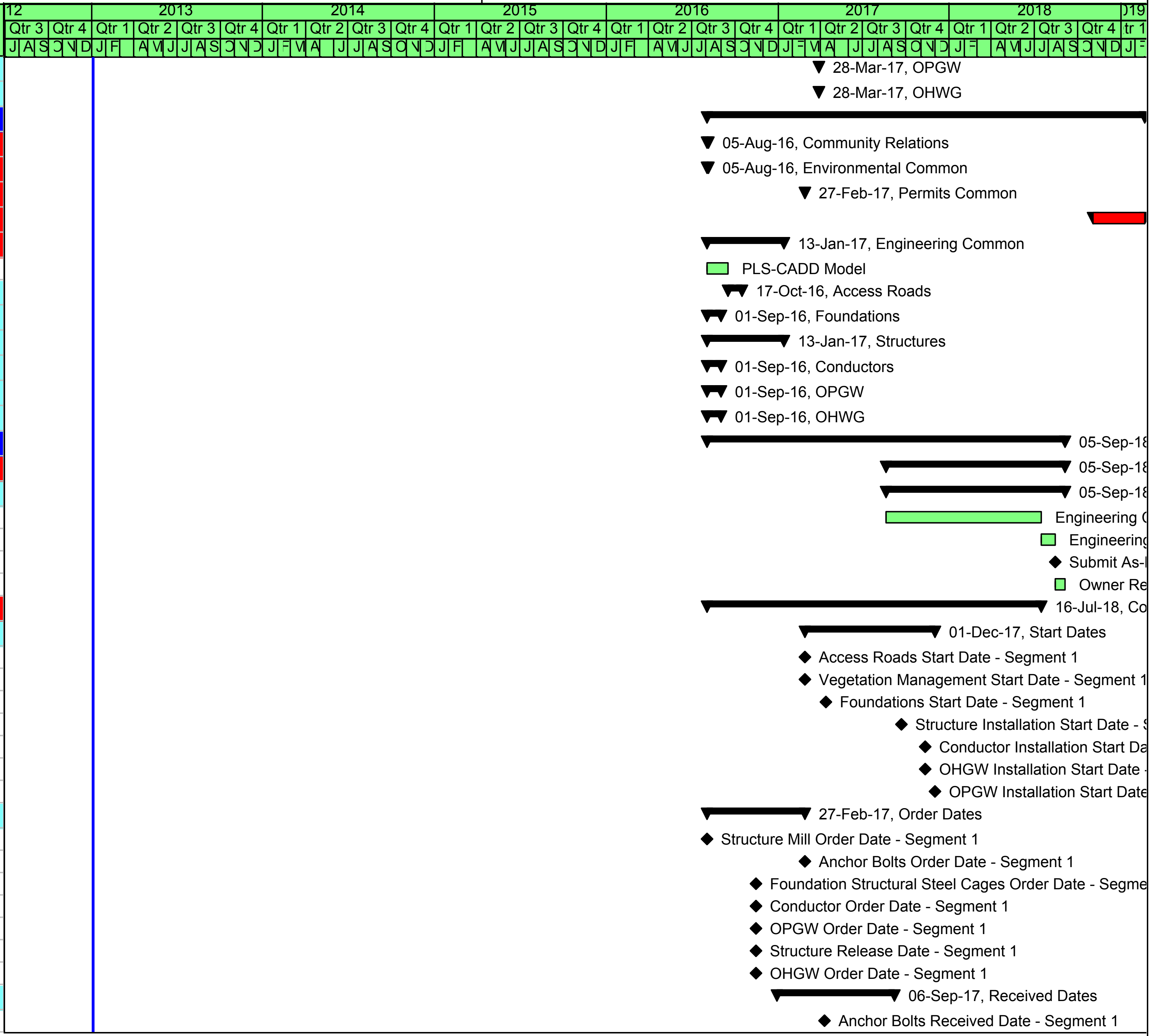
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
OPGW		28-Mar-17	28-Mar-17
OHWG		28-Mar-17	28-Mar-17
Project Common		04-Aug-16	20-Feb-19
Community Relations		04-Aug-16	05-Aug-16
Environmental Common		04-Aug-16	05-Aug-16
Permits Common		27-Feb-17	27-Feb-17
General		02-Nov-18	20-Feb-19
Engineering Common		04-Aug-16	13-Jan-17
A60350	PLS-CADD Model	04-Aug-16	16-Sep-16
Access Roads		16-Sep-16	17-Oct-16
Foundations		04-Aug-16	01-Sep-16
Structures		04-Aug-16	13-Jan-17
Conductors		04-Aug-16	01-Sep-16
OPGW		04-Aug-16	01-Sep-16
OHWG		04-Aug-16	01-Sep-16
Segment 1 Thunder Bay - Nipigon River (85 km)		04-Aug-16	05-Sep-18
Project Management		18-Aug-17	05-Sep-18
Project Support		18-Aug-17	05-Sep-18
S1-ENG-9000	Engineering Construction Support - Segment 1	18-Aug-17	16-Jul-18
S1-ENG-9010	Engineering As-Builts - Segment 1	16-Jul-18	14-Aug-18
S1-ENG-9020	Submit As-Builts - Segment 1		14-Aug-18
S1-ENG-9030	Owner Review As-Builts - Segment 1	14-Aug-18	05-Sep-18
Contractor Milestones Segment 1		04-Aug-16	16-Jul-18
Start Dates		27-Feb-17	01-Dec-17
S1-SD-MS-1010	Access Roads Start Date - Segment 1	27-Feb-17	
S1-SD-MS-1020	Vegetation Management Start Date - Segment 1	27-Feb-17	
S1-SD-MS-1030	Foundations Start Date - Segment 1	12-Apr-17	
S1-SD-MS-1040	Structure Installation Start Date - Segment 1	20-Sep-17	
S1-SD-MS-1050	Conductor Installation Start Date - Segment 1	09-Nov-17	
S1-SD-MS-1060	OHGW Installation Start Date - Segment 1	09-Nov-17	
S1-SD-MS-1070	OPGW Installation Start Date - Segment 1	01-Dec-17	
Order Dates		04-Aug-16	27-Feb-17
S1-OD-MS-1000	Structure Mill Order Date - Segment 1	04-Aug-16	
S1-OD-MS-1010	Anchor Bolts Order Date - Segment 1	27-Feb-17	
S1-OD-MS-1020	Foundation Structural Steel Cages Order Date - Segment 1	16-Nov-16	
S1-OD-MS-1030	Conductor Order Date - Segment 1	16-Nov-16	
S1-OD-MS-1040	OPGW Order Date - Segment 1	16-Nov-16	
S1-OD-MS-1050	Structure Release Date - Segment 1	16-Nov-16	
S1-OD-MS-1060	OHGW Order Date - Segment 1	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S1-RD-MS-1010	Anchor Bolts Received Date - Segment 1		11-Apr-17



- 🟩 Remaining Level of Effort
- 🟦 Actual Level of Effort
- 🟦 Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ ◆ Milestone
- % Complete
- Summary

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

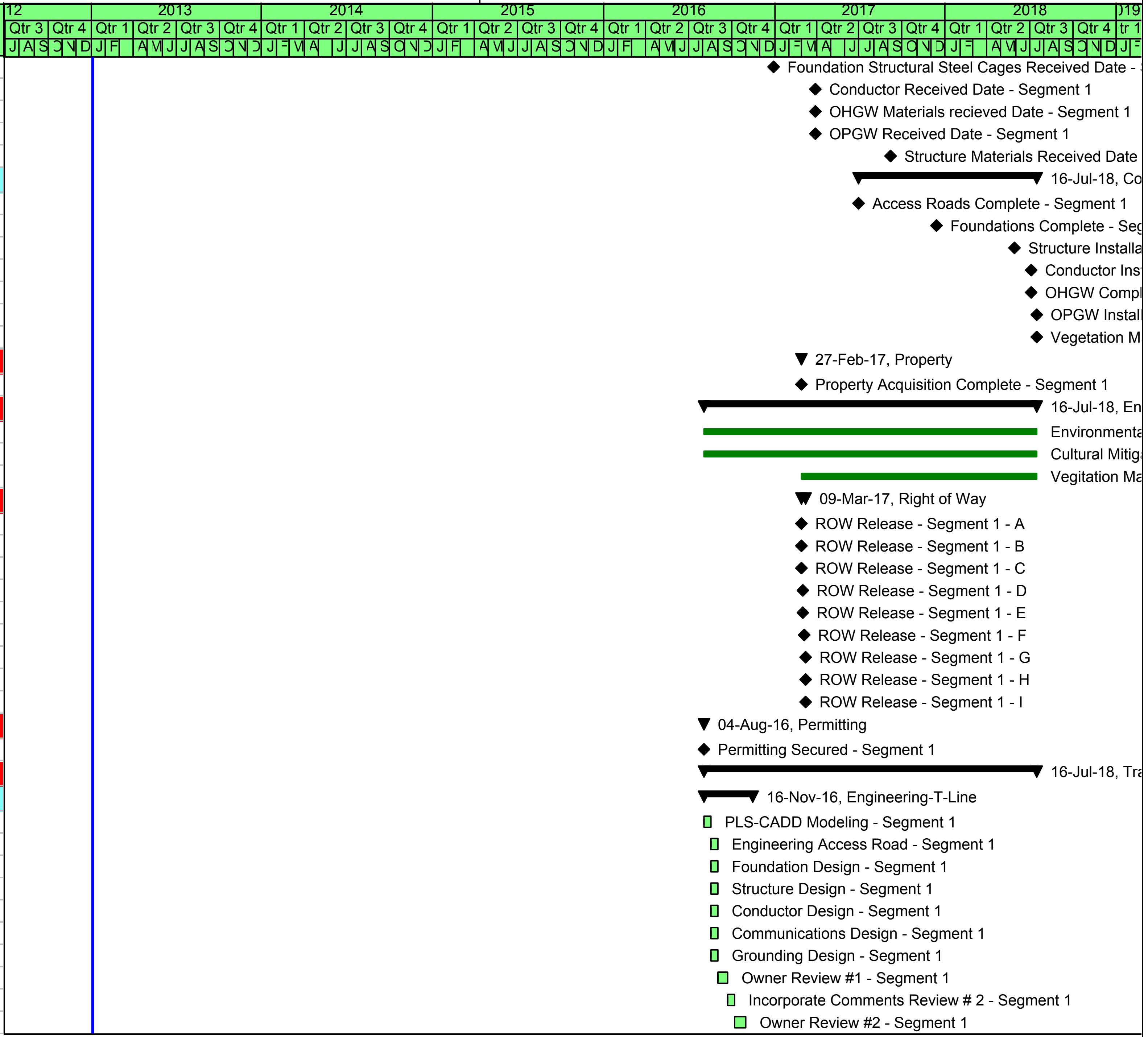
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S1-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segm...		30-Dec-16
S1-RD-MS-1030	Conductor Received Date - Segment 1		28-Mar-17
S1-RD-MS-1040	OHGW Materials recieved Date - Segment 1		28-Mar-17
S1-RD-MS-1050	OPGW Received Date - Segment 1		28-Mar-17
S1-RD-MS-1060	Structure Materials Received Date - Segment 1 (40weeks)		06-Sep-17
Completion Dates		29-Jun-17	16-Jul-18
S1-CD-MS-1010	Access Roads Complete - Segment 1		29-Jun-17
S1-CD-MS-1020	Foundations Complete - Segment 1		13-Dec-17
S1-CD-MS-1030	Structure Installation Complete - Segment 1		29-May-18
S1-CD-MS-1040	Conductor Installation Complete - Segment 1		04-Jul-18
S1-CD-MS-1050	OHGW Complete - Segment 1		04-Jul-18
S1-CD-MS-1060	OPGW Installation Complete - Segment 1		16-Jul-18
S1-CD-MS-1070	Vegetation Management Complete - Segment 1		16-Jul-18
Property		27-Feb-17	27-Feb-17
S1-PRP-1000	Property Acquisition Complete - Segment 1		27-Feb-17
Environmental		04-Aug-16	16-Jul-18
S1-ENV-1000	Environmental Monitoring- Segment 1	04-Aug-16	16-Jul-18
S1-ENV-1010	Cultural Mitigation - Segment 1	04-Aug-16	16-Jul-18
S1-ENV-1020	Vegitation Management - Segment 1	27-Feb-17	16-Jul-18
Right of Way		27-Feb-17	09-Mar-17
ROW-1A	ROW Release - Segment 1 - A	27-Feb-17	
ROW-1B	ROW Release - Segment 1 - B	28-Feb-17	
ROW-1C	ROW Release - Segment 1 - C	01-Mar-17	
ROW-1D	ROW Release - Segment 1 - D	02-Mar-17	
ROW-1E	ROW Release - Segment 1 - E	03-Mar-17	
ROW-1F	ROW Release - Segment 1 - F	06-Mar-17	
ROW-1G	ROW Release - Segment 1 - G	07-Mar-17	
ROW-1H	ROW Release - Segment 1 - H	08-Mar-17	
ROW-1I	ROW Release - Segment 1 - I	09-Mar-17	
Permitting		04-Aug-16	04-Aug-16
S1-PMT-1000	Permitting Secured - Segment 1		04-Aug-16
Transmission Lines		04-Aug-16	16-Jul-18
Engineering-T-Line		04-Aug-16	16-Nov-16
S1-ENG-1000	PLS-CADD Modeling - Segment 1	04-Aug-16	18-Aug-16
S1-ENG-1010	Engineering Access Road - Segment 1	18-Aug-16	01-Sep-16
S1-ENG-1020	Foundation Design - Segment 1	18-Aug-16	01-Sep-16
S1-ENG-1030	Structure Design - Segment 1	18-Aug-16	01-Sep-16
S1-ENG-1040	Conductor Design - Segment 1	18-Aug-16	01-Sep-16
S1-ENG-1050	Communications Design - Segment 1	18-Aug-16	01-Sep-16
S1-ENG-1060	Grounding Design - Segment 1	18-Aug-16	01-Sep-16
S1-ENG-1070	Owner Review #1 - Segment 1	01-Sep-16	23-Sep-16
S1-ENG-1080	Incorporate Comments Review # 2 - Segment 1	23-Sep-16	07-Oct-16
S1-ENG-1090	Owner Review #2 - Segment 1	07-Oct-16	31-Oct-16



🟩 Remaining Level of Effort
▬ % Complete
🟦 Actual Level of Effort
▼ Summary
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

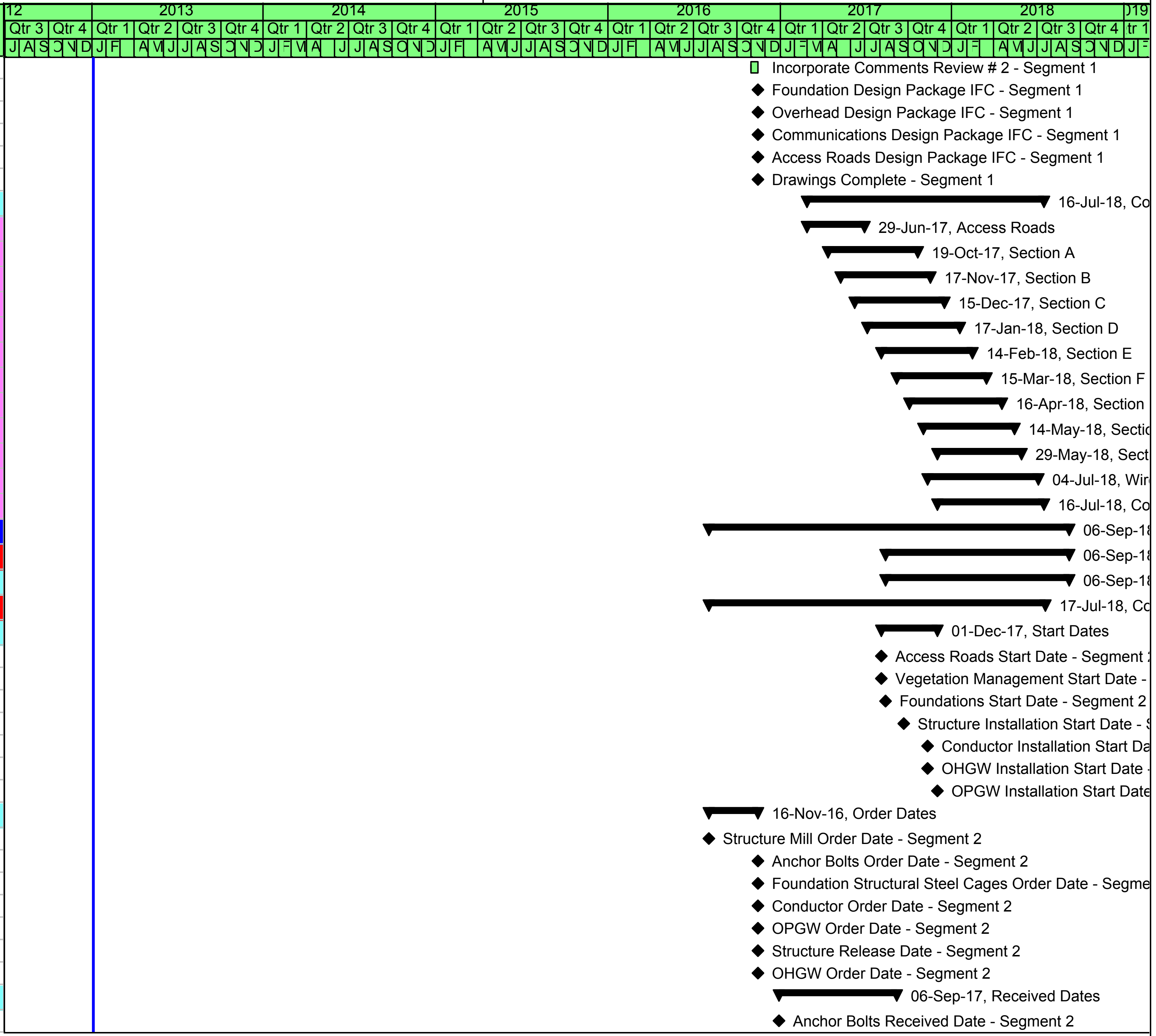
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S1-ENG-1100	Incorporate Comments Review # 2 - Segment 1	31-Oct-16	15-Nov-16
S1-ENG-1120	Foundation Design Package IFC - Segment 1		15-Nov-16
S1-ENG-1130	Overhead Design Package IFC - Segment 1		15-Nov-16
S1-ENG-1140	Communications Design Package IFC - Segment 1		15-Nov-16
S1-ENG-1150	Access Roads Design Package IFC - Segment 1		15-Nov-16
S1-ENG-1160	Drawings Complete - Segment 1		16-Nov-16
Construction-T-Line		27-Feb-17	16-Jul-18
Access Roads		27-Feb-17	29-Jun-17
Section A		12-Apr-17	19-Oct-17
Section B		10-May-17	17-Nov-17
Section C		08-Jun-17	15-Dec-17
Section D		07-Jul-17	17-Jan-18
Section E		04-Aug-17	14-Feb-18
Section F		05-Sep-17	15-Mar-18
Section G		03-Oct-17	16-Apr-18
Section H		01-Nov-17	14-May-18
Section I		30-Nov-17	29-May-18
Wire Runs		09-Nov-17	04-Jul-18
Communications		01-Dec-17	16-Jul-18
Segment 2 Nipigon River - Terrace Bay (86 km)		04-Aug-16	06-Sep-18
Project Management		14-Aug-17	06-Sep-18
Project Support		14-Aug-17	06-Sep-18
Contractor Milestones Segment 2		04-Aug-16	17-Jul-18
Start Dates		04-Aug-17	01-Dec-17
S2-SD-MS-1010	Access Roads Start Date - Segment 2	04-Aug-17	
S2-SD-MS-1020	Vegetation Management Start Date - Segment 2	04-Aug-17	
S2-SD-MS-1030	Foundations Start Date - Segment 2	14-Aug-17	
S2-SD-MS-1040	Structure Installation Start Date - Segment 2	20-Sep-17	
S2-SD-MS-1050	Conductor Installation Start Date - Segment 2	09-Nov-17	
S2-SD-MS-1060	OHGW Installation Start Date - Segment 2	09-Nov-17	
S2-SD-MS-1070	OPGW Installation Start Date - Segment 2	01-Dec-17	
Order Dates		04-Aug-16	16-Nov-16
S2-OD-MS-1010	Structure Mill Order Date - Segment 2	04-Aug-16	
S2-OD-MS-1020	Anchor Bolts Order Date - Segment 2	16-Nov-16	
S2-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 2	16-Nov-16	
S2-OD-MS-1040	Conductor Order Date - Segment 2	16-Nov-16	
S2-OD-MS-1050	OPGW Order Date - Segment 2	16-Nov-16	
S2-OD-MS-1060	Structure Release Date - Segment 2	16-Nov-16	
S2-OD-MS-1070	OHGW Order Date - Segment 2	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S2-RD-MS-1010	Anchor Bolts Received Date - Segment 2		30-Dec-16



🟩 Remaining Level of Effort	▬ % Complete
🟦 Actual Level of Effort	▼ Summary
🟦 Actual Work	
🟩 Remaining Work	
🟥 Critical Remaining Work	
◆ ◆ Milestone	

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

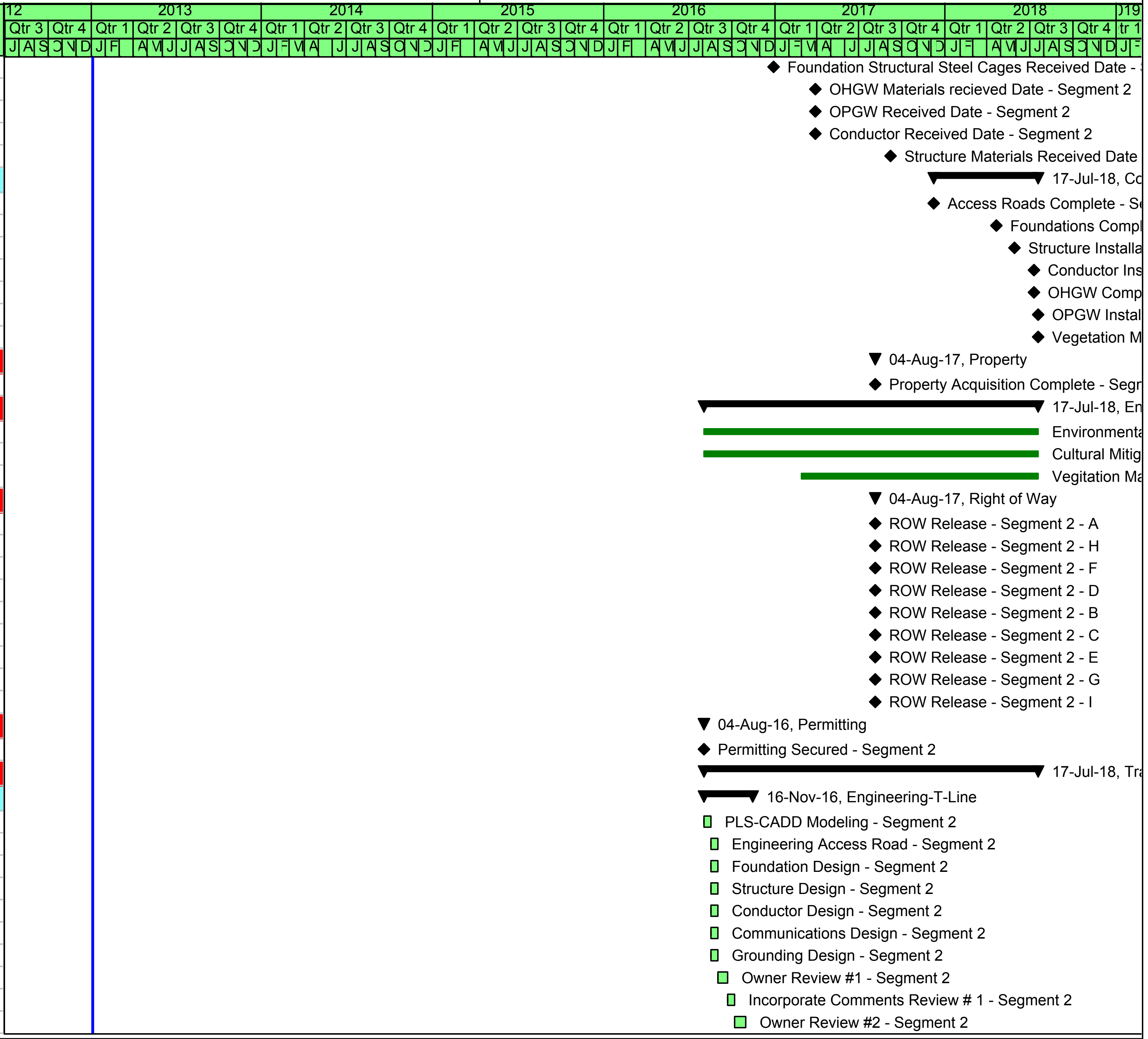
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S2-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segm...		30-Dec-16
S2-RD-MS-1030	OHGW Materials recieved Date - Segment 2		28-Mar-17
S2-RD-MS-1040	OPGW Received Date - Segment 2		28-Mar-17
S2-RD-MS-1050	Conductor Received Date - Segment 2		28-Mar-17
S2-RD-MS-1060	Structure Materials Received Date - Segment 2		06-Sep-17
Completion Dates		08-Dec-17	17-Jul-18
S2-CD-MS-1010	Access Roads Complete - Segment 2		08-Dec-17
S2-CD-MS-1020	Foundations Complete - Segment 2		20-Apr-18
S2-CD-MS-1030	Structure Installation Complete - Segment 2		29-May-18
S2-CD-MS-1040	Conductor Installation Complete - Segment 2		09-Jul-18
S2-CD-MS-1050	OHGW Complete - Segment 2		09-Jul-18
S2-CD-MS-1060	OPGW Installation Complete - Segment 2		17-Jul-18
S2-CD-MS-1070	Vegetation Management Complete - Segment 2		17-Jul-18
Property		04-Aug-17	04-Aug-17
S2-PRP-1000	Property Acquisition Complete - Segment 2		04-Aug-17
Environmental		04-Aug-16	17-Jul-18
S2-ENV-1000	Environmental Monitoring- Segment 2	04-Aug-16	17-Jul-18
S2-ENV-1010	Cultural Mitigation - Segment 2	04-Aug-16	17-Jul-18
S2-ENV-1020	Vegitation Management - Segment 2	27-Feb-17	17-Jul-18
Right of Way		04-Aug-17	04-Aug-17
S2-ROW-1000	ROW Release - Segment 2 - A	04-Aug-17	
S2-ROW-1010	ROW Release - Segment 2 - H	04-Aug-17	
S2-ROW-1020	ROW Release - Segment 2 - F	04-Aug-17	
S2-ROW-1030	ROW Release - Segment 2 - D	04-Aug-17	
S2-ROW-1040	ROW Release - Segment 2 - B	04-Aug-17	
S2-ROW-1050	ROW Release - Segment 2 - C	04-Aug-17	
S2-ROW-1060	ROW Release - Segment 2 - E	04-Aug-17	
S2-ROW-1070	ROW Release - Segment 2 - G	04-Aug-17	
S2-ROW-1080	ROW Release - Segment 2 - I	04-Aug-17	
Permitting		04-Aug-16	04-Aug-16
S2-PMT-1000	Permitting Secured - Segment 2		04-Aug-16
Transmission Lines		04-Aug-16	17-Jul-18
Engineering-T-Line		04-Aug-16	16-Nov-16
S2-ENG-1000	PLS-CADD Modeling - Segment 2	04-Aug-16	18-Aug-16
S2-ENG-1010	Engineering Access Road - Segment 2	18-Aug-16	01-Sep-16
S2-ENG-1020	Foundation Design - Segment 2	18-Aug-16	01-Sep-16
S2-ENG-1030	Structure Design - Segment 2	18-Aug-16	01-Sep-16
S2-ENG-1040	Conductor Design - Segment 2	18-Aug-16	01-Sep-16
S2-ENG-1050	Communications Design - Segment 2	18-Aug-16	01-Sep-16
S2-ENG-1060	Grounding Design - Segment 2	18-Aug-16	01-Sep-16
S2-ENG-1070	Owner Review #1 - Segment 2	01-Sep-16	23-Sep-16
S2-ENG-1080	Incorporate Comments Review # 1 - Segment 2	23-Sep-16	07-Oct-16
S2-ENG-1090	Owner Review #2 - Segment 2	07-Oct-16	31-Oct-16



Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
◆ ◆ Milestone
% Complete
Summary

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

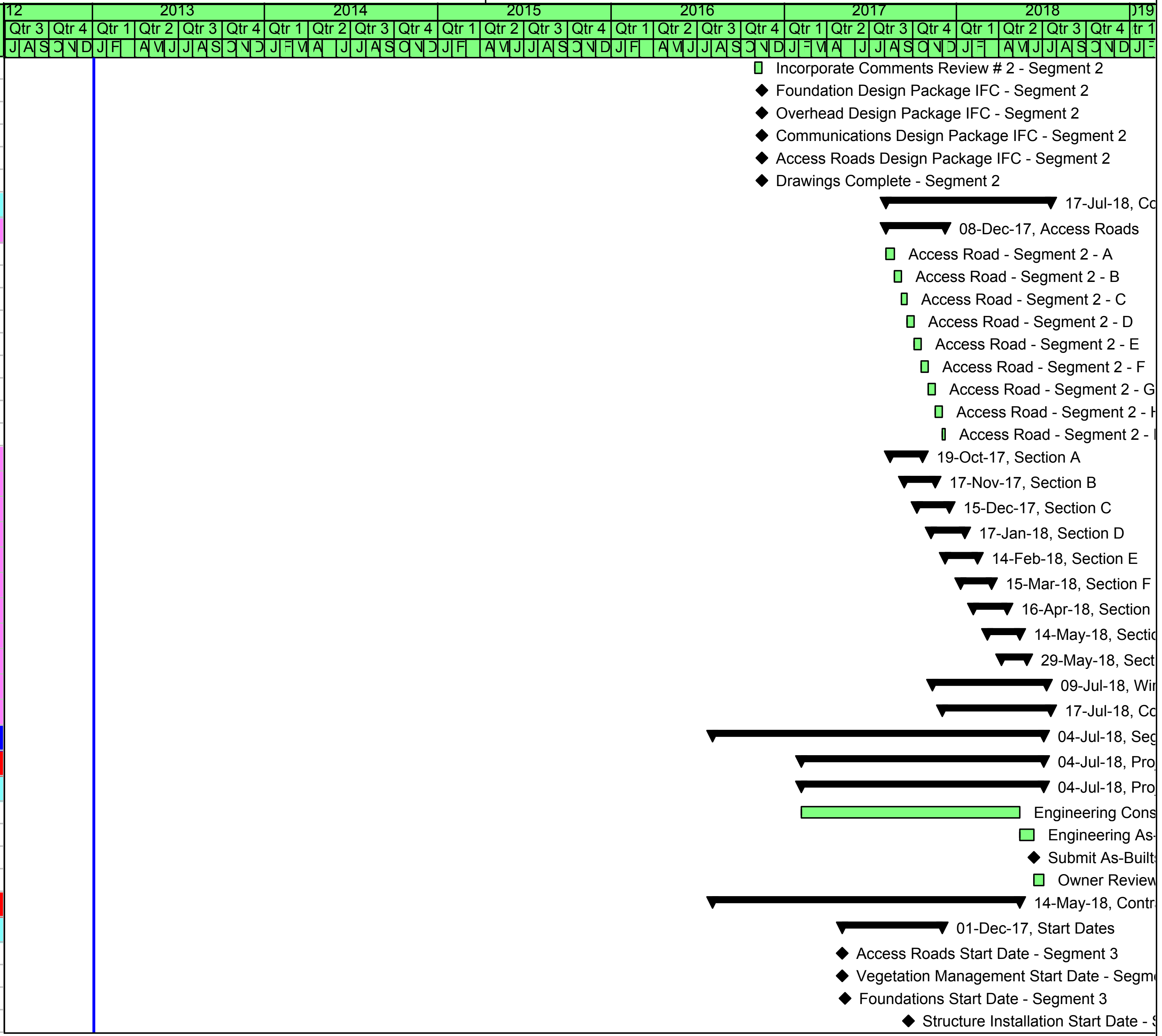
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S2-ENG-1100	Incorporate Comments Review # 2 - Segment 2	31-Oct-16	15-Nov-16
S2-ENG-1120	Foundation Design Package IFC - Segment 2		15-Nov-16
S2-ENG-1130	Overhead Design Package IFC - Segment 2		15-Nov-16
S2-ENG-1140	Communications Design Package IFC - Segment 2		15-Nov-16
S2-ENG-1150	Access Roads Design Package IFC - Segment 2		15-Nov-16
S2-ENG-1160	Drawings Complete - Segment 2		16-Nov-16
Construction-T-Line		04-Aug-17	17-Jul-18
Access Roads		04-Aug-17	08-Dec-17
S2-AR-1000	Access Road - Segment 2 - A	04-Aug-17	21-Aug-17
S2-AR-1010	Access Road - Segment 2 - B	21-Aug-17	05-Sep-17
S2-AR-1020	Access Road - Segment 2 - C	05-Sep-17	19-Sep-17
S2-AR-1030	Access Road - Segment 2 - D	19-Sep-17	03-Oct-17
S2-AR-1040	Access Road - Segment 2 - E	03-Oct-17	18-Oct-17
S2-AR-1050	Access Road - Segment 2 - F	18-Oct-17	01-Nov-17
S2-AR-1060	Access Road - Segment 2 - G	01-Nov-17	16-Nov-17
S2-AR-1070	Access Road - Segment 2 - H	16-Nov-17	30-Nov-17
S2-AR-1080	Access Road - Segment 2 - I	30-Nov-17	08-Dec-17
Section A		14-Aug-17	19-Oct-17
Section B		12-Sep-17	17-Nov-17
Section C		10-Oct-17	15-Dec-17
Section D		08-Nov-17	17-Jan-18
Section E		07-Dec-17	14-Feb-18
Section F		09-Jan-18	15-Mar-18
Section G		06-Feb-18	16-Apr-18
Section H		07-Mar-18	14-May-18
Section I		06-Apr-18	29-May-18
Wire Runs		09-Nov-17	09-Jul-18
Communications		01-Dec-17	17-Jul-18
Segment 3 Terrace Bay - Marathon (60 km)		04-Aug-16	04-Jul-18
Project Management		06-Feb-17	04-Jul-18
Project Support		06-Feb-17	04-Jul-18
S3-ENG-9000	Engineering Construction Support - Segment 3	06-Feb-17	14-May-18
S3-ENG-9010	Engineering As-Builts - Segment 3	14-May-18	12-Jun-18
S3-ENG-9020	Submit As-Builts - Segment 3		12-Jun-18
S3-ENG-9030	Owner Review As-Builts - Segment 3	12-Jun-18	04-Jul-18
Contractor Milestones Segment 3		04-Aug-16	14-May-18
Start Dates		03-May-17	01-Dec-17
S3-SD-MS-1010	Access Roads Start Date - Segment 3	03-May-17	
S3-SD-MS-1020	Vegetation Management Start Date - Segment 3	03-May-17	
S3-SD-MS-1030	Foundations Start Date - Segment 3	10-May-17	
S3-SD-MS-1040	Structure Installation Start Date - Segment 3	20-Sep-17	



🟩	Remaining Level of Effort	▬	% Complete
🟦	Actual Level of Effort	▼	Summary
🟦	Actual Work		
🟩	Remaining Work		
🟥	Critical Remaining Work		
◆	◆ Milestone		

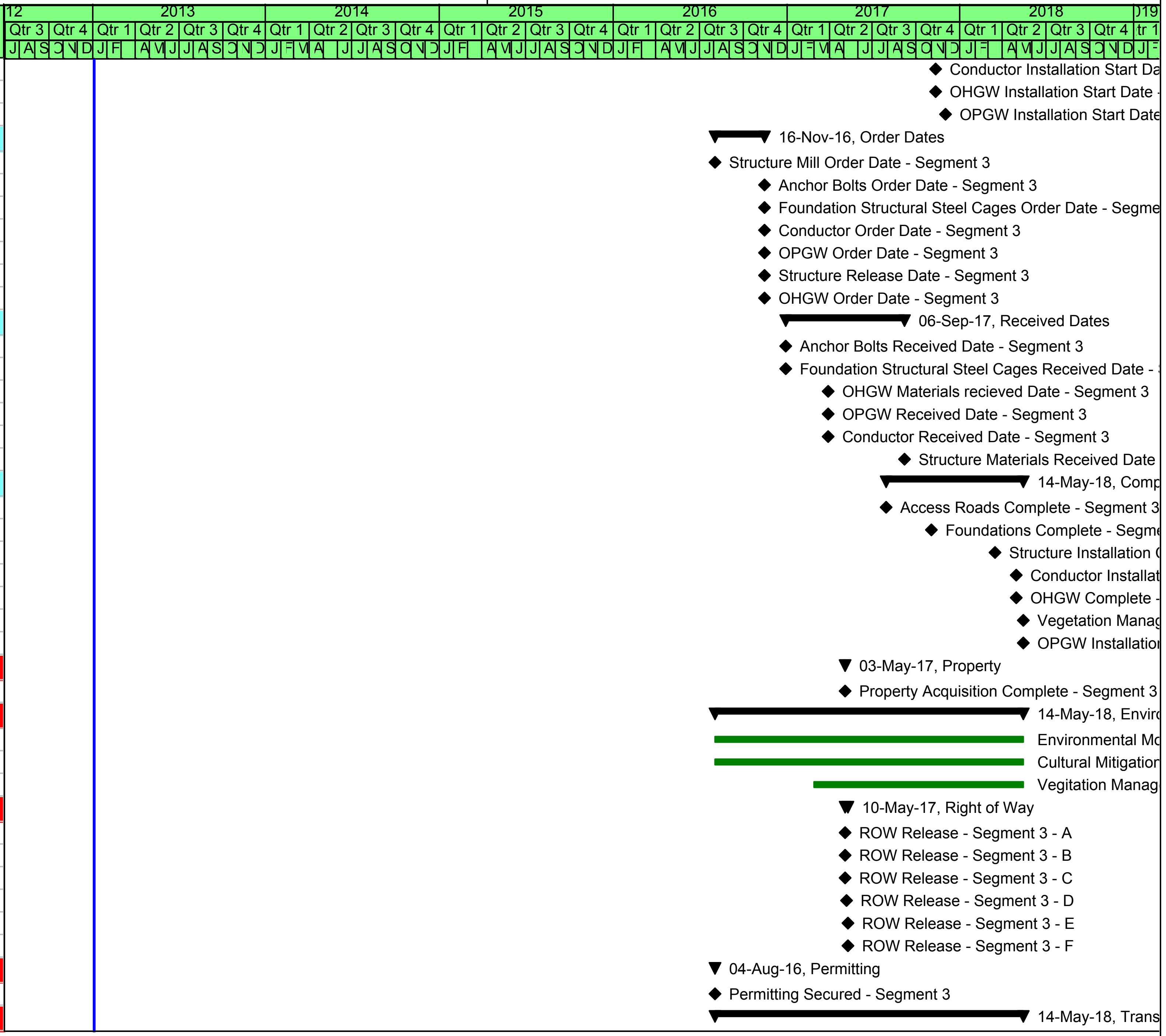
Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

Activity ID	Activity Name	Start	Finish
S3-SD-MS-1050	Conductor Installation Start Date - Segment 3	09-Nov-17	
S3-SD-MS-1060	OHGW Installation Start Date - Segment 3	09-Nov-17	
S3-SD-MS-1070	OPGW Installation Start Date - Segment 3	01-Dec-17	
Order Dates		04-Aug-16	16-Nov-16
S3-OD-MS-1010	Structure Mill Order Date - Segment 3	04-Aug-16	
S3-OD-MS-1020	Anchor Bolts Order Date - Segment 3	16-Nov-16	
S3-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 3	16-Nov-16	
S3-OD-MS-1040	Conductor Order Date - Segment 3	16-Nov-16	
S3-OD-MS-1050	OPGW Order Date - Segment 3	16-Nov-16	
S3-OD-MS-1060	Structure Release Date - Segment 3	16-Nov-16	
S3-OD-MS-1070	OHGW Order Date - Segment 3	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S3-RD-MS-1010	Anchor Bolts Received Date - Segment 3		30-Dec-16
S3-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segm...		30-Dec-16
S3-RD-MS-1030	OHGW Materials recieved Date - Segment 3		28-Mar-17
S3-RD-MS-1040	OPGW Received Date - Segment 3		28-Mar-17
S3-RD-MS-1050	Conductor Received Date - Segment 3		28-Mar-17
S3-RD-MS-1060	Structure Materials Received Date - Segment 3		06-Sep-17
Completion Dates		28-Jul-17	14-May-18
S3-CD-MS-1010	Access Roads Complete - Segment 3		28-Jul-17
S3-CD-MS-1020	Foundations Complete - Segment 3		01-Nov-17
S3-CD-MS-1030	Structure Installation Complete - Segment 3		15-Mar-18
S3-CD-MS-1040	Conductor Installation Complete - Segment 3		30-Apr-18
S3-CD-MS-1060	OHGW Complete - Segment 3		30-Apr-18
S3-CD-MS-1070	Vegetation Management Complete - Segment 3		14-May-18
S3-CD-MS-1080	OPGW Installation Complete - Segment 3		14-May-18
Property		03-May-17	03-May-17
A62990	Property Acquisition Complete - Segment 3		03-May-17
Environmental		04-Aug-16	14-May-18
S3-ENV-1000	Environmental Monitoring- Segment 3	04-Aug-16	14-May-18
S3-ENV-1010	Cultural Mitigation - Segment 3	04-Aug-16	14-May-18
S3-ENV-1020	Vegitation Management - Segment 3	27-Feb-17	14-May-18
Right of Way		03-May-17	10-May-17
S3-ROW-1000	ROW Release - Segment 3 - A	03-May-17	
S3-ROW-1010	ROW Release - Segment 3 - B	04-May-17	
S3-ROW-1020	ROW Release - Segment 3 - C	05-May-17	
S3-ROW-1030	ROW Release - Segment 3 - D	08-May-17	
S3-ROW-1040	ROW Release - Segment 3 - E	09-May-17	
S3-ROW-1050	ROW Release - Segment 3 - F	10-May-17	
Permitting		04-Aug-16	04-Aug-16
S3-PMT-1000	Permitting Secured - Segment 3		04-Aug-16
Transmission Lines		04-Aug-16	14-May-18



- 🟩 Remaining Level of Effort
- 🟦 Actual Level of Effort
- 🟦 Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ Milestone
- ▬ % Complete
- ▼ Summary

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

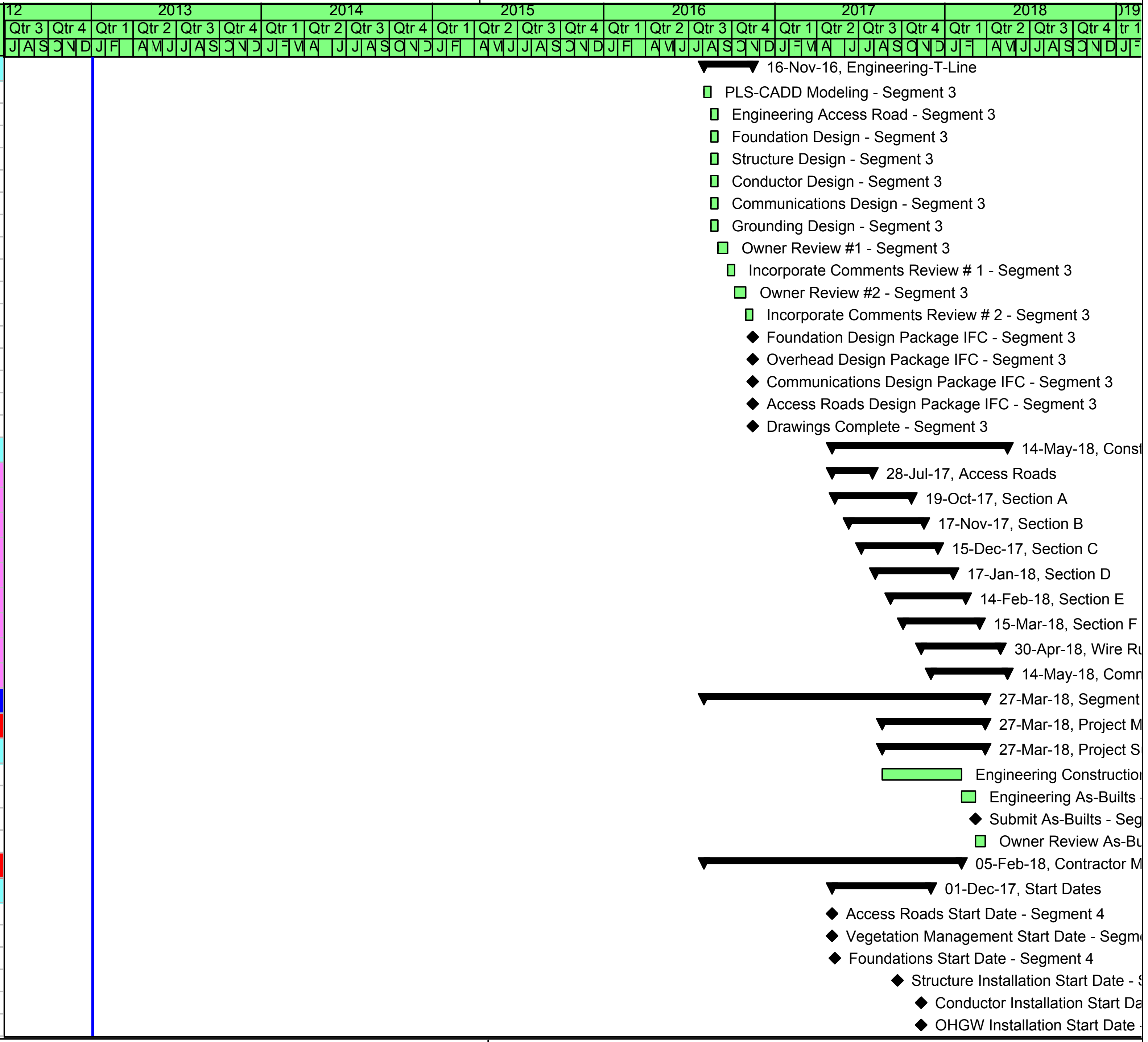
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
Engineering-T-Line		04-Aug-16	16-Nov-16
S3-ENG-1000	PLS-CADD Modeling - Segment 3	04-Aug-16	18-Aug-16
S3-ENG-1010	Engineering Access Road - Segment 3	18-Aug-16	01-Sep-16
S3-ENG-1020	Foundation Design - Segment 3	18-Aug-16	01-Sep-16
S3-ENG-1030	Structure Design - Segment 3	18-Aug-16	01-Sep-16
S3-ENG-1040	Conductor Design - Segment 3	18-Aug-16	01-Sep-16
S3-ENG-1050	Communications Design - Segment 3	18-Aug-16	01-Sep-16
S3-ENG-1060	Grounding Design - Segment 3	18-Aug-16	01-Sep-16
S3-ENG-1070	Owner Review #1 - Segment 3	01-Sep-16	23-Sep-16
S3-ENG-1080	Incorporate Comments Review # 1 - Segment 3	23-Sep-16	07-Oct-16
S3-ENG-1090	Owner Review #2 - Segment 3	07-Oct-16	31-Oct-16
S3-ENG-1100	Incorporate Comments Review # 2 - Segment 3	31-Oct-16	15-Nov-16
S3-ENG-1120	Foundation Design Package IFC - Segment 3		15-Nov-16
S3-ENG-1130	Overhead Design Package IFC - Segment 3		15-Nov-16
S3-ENG-1140	Communications Design Package IFC - Segment 3		15-Nov-16
S3-ENG-1150	Access Roads Design Package IFC - Segment 3		15-Nov-16
S3-ENG-1160	Drawings Complete - Segment 3		16-Nov-16
Construction-T-Line		03-May-17	14-May-18
Access Roads		03-May-17	28-Jul-17
Section A		10-May-17	19-Oct-17
Section B		08-Jun-17	17-Nov-17
Section C		07-Jul-17	15-Dec-17
Section D		04-Aug-17	17-Jan-18
Section E		05-Sep-17	14-Feb-18
Section F		03-Oct-17	15-Mar-18
Wire Runs		09-Nov-17	30-Apr-18
Communications		01-Dec-17	14-May-18
Segment 4 Marathon - White River (28 km)		04-Aug-16	27-Mar-18
Project Management		18-Aug-17	27-Mar-18
Project Support		18-Aug-17	27-Mar-18
S4-ENG-9000	Engineering Construction Support - Segment 4	18-Aug-17	05-Feb-18
S4-ENG-9010	Engineering As-Builts - Segment 4	05-Feb-18	06-Mar-18
S4-ENG-9020	Submit As-Builts - Segment 4		06-Mar-18
S4-ENG-9030	Owner Review As-Builts - Segment 4	06-Mar-18	27-Mar-18
Contractor Milestones Segment 4		04-Aug-16	05-Feb-18
Start Dates		03-May-17	01-Dec-17
S4-SD-MS-1010	Access Roads Start Date - Segment 4	03-May-17	
S4-SD-MS-1020	Vegetation Management Start Date - Segment 4	03-May-17	
S4-SD-MS-1030	Foundations Start Date - Segment 4	10-May-17	
S4-SD-MS-1040	Structure Installation Start Date - Segment 4	20-Sep-17	
S4-SD-MS-1050	Conductor Installation Start Date - Segment 4	09-Nov-17	
S4-SD-MS-1060	OHGW Installation Start Date - Segment 4	09-Nov-17	



🟩	Remaining Level of Effort	▬	% Complete
🟦	Actual Level of Effort	▼▬▼	Summary
🟦	Actual Work		
🟩	Remaining Work		
🟥	Critical Remaining Work		
◆ ◆	Milestone		

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

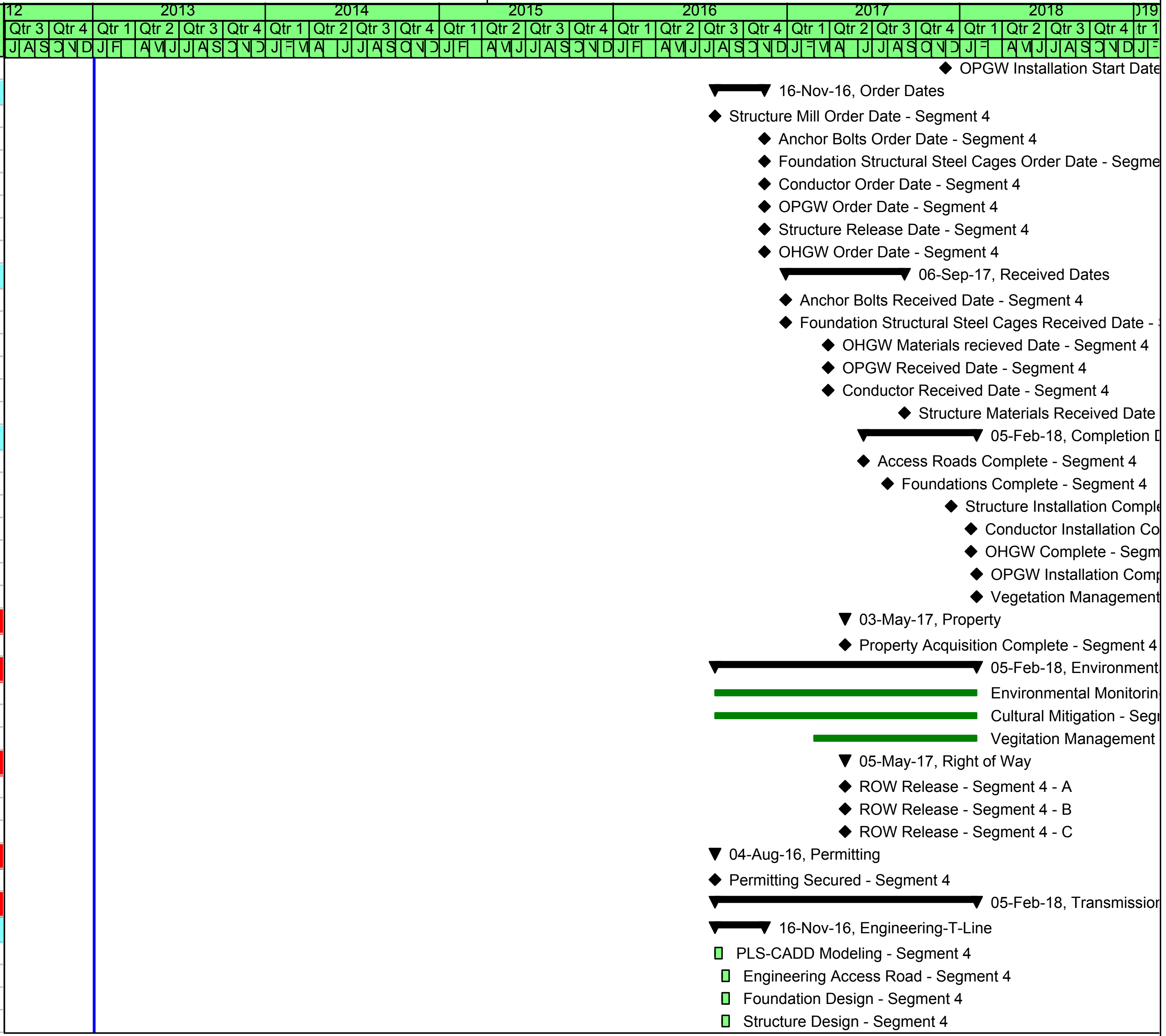
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S4-SD-MS-1070	OPGW Installation Start Date - Segment 4	01-Dec-17	
Order Dates		04-Aug-16	16-Nov-16
S4-OD-MS-1010	Structure Mill Order Date - Segment 4	04-Aug-16	
S4-OD-MS-1020	Anchor Bolts Order Date - Segment 4	16-Nov-16	
S4-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 4	16-Nov-16	
S4-OD-MS-1040	Conductor Order Date - Segment 4	16-Nov-16	
S4-OD-MS-1050	OPGW Order Date - Segment 4	16-Nov-16	
S4-OD-MS-1060	Structure Release Date - Segment 4	16-Nov-16	
S4-OD-MS-1070	OHGW Order Date - Segment 4	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S4-RD-MS-1010	Anchor Bolts Received Date - Segment 4		30-Dec-16
S4-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segm...		30-Dec-16
S4-RD-MS-1030	OHGW Materials recieved Date - Segment 4		28-Mar-17
S4-RD-MS-1040	OPGW Received Date - Segment 4		28-Mar-17
S4-RD-MS-1050	Conductor Received Date - Segment 4		28-Mar-17
S4-RD-MS-1060	Structure Materials Received Date - Segment 4		06-Sep-17
Completion Dates		13-Jun-17	05-Feb-18
S4-CD-MS-1010	Access Roads Complete - Segment 4		13-Jun-17
S4-CD-MS-1020	Foundations Complete - Segment 4		02-Aug-17
S4-CD-MS-1030	Structure Installation Complete - Segment 4		13-Dec-17
S4-CD-MS-1040	Conductor Installation Complete - Segment 4		24-Jan-18
S4-CD-MS-1050	OHGW Complete - Segment 4		24-Jan-18
S4-CD-MS-1060	OPGW Installation Complete - Segment 4		05-Feb-18
S4-CD-MS-1070	Vegetation Management Complete - Segment 4		05-Feb-18
Property		03-May-17	03-May-17
S4-PRP-1000	Property Acquisition Complete - Segment 4		03-May-17
Environmental		04-Aug-16	05-Feb-18
S4-ENV-1000	Environmental Monitoring- Segment 4	04-Aug-16	05-Feb-18
S4-ENV-1010	Cultural Mitigation - Segment 4	04-Aug-16	05-Feb-18
S4-ENV-1020	Vegitation Management - Segment 4	27-Feb-17	05-Feb-18
Right of Way		03-May-17	05-May-17
S4-ROW-1000	ROW Release - Segment 4 - A	03-May-17	
S4-ROW-1010	ROW Release - Segment 4 - B	04-May-17	
S4-ROW-1020	ROW Release - Segment 4 - C	05-May-17	
Permitting		04-Aug-16	04-Aug-16
S4-PMT-1000	Permitting Secured - Segment 4		04-Aug-16
Transmission Lines		04-Aug-16	05-Feb-18
Engineering-T-Line		04-Aug-16	16-Nov-16
S4-ENG-1000	PLS-CADD Modeling - Segment 4	04-Aug-16	18-Aug-16
S4-ENG-1010	Engineering Access Road - Segment 4	18-Aug-16	01-Sep-16
S4-ENG-1020	Foundation Design - Segment 4	18-Aug-16	01-Sep-16
S4-ENG-1030	Structure Design - Segment 4	18-Aug-16	01-Sep-16



- 🟩 Remaining Level of Effort
- ▬ Actual Level of Effort
- 🟦 Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ ◆ Milestone
- ▬ % Complete
- ▼ Summary

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

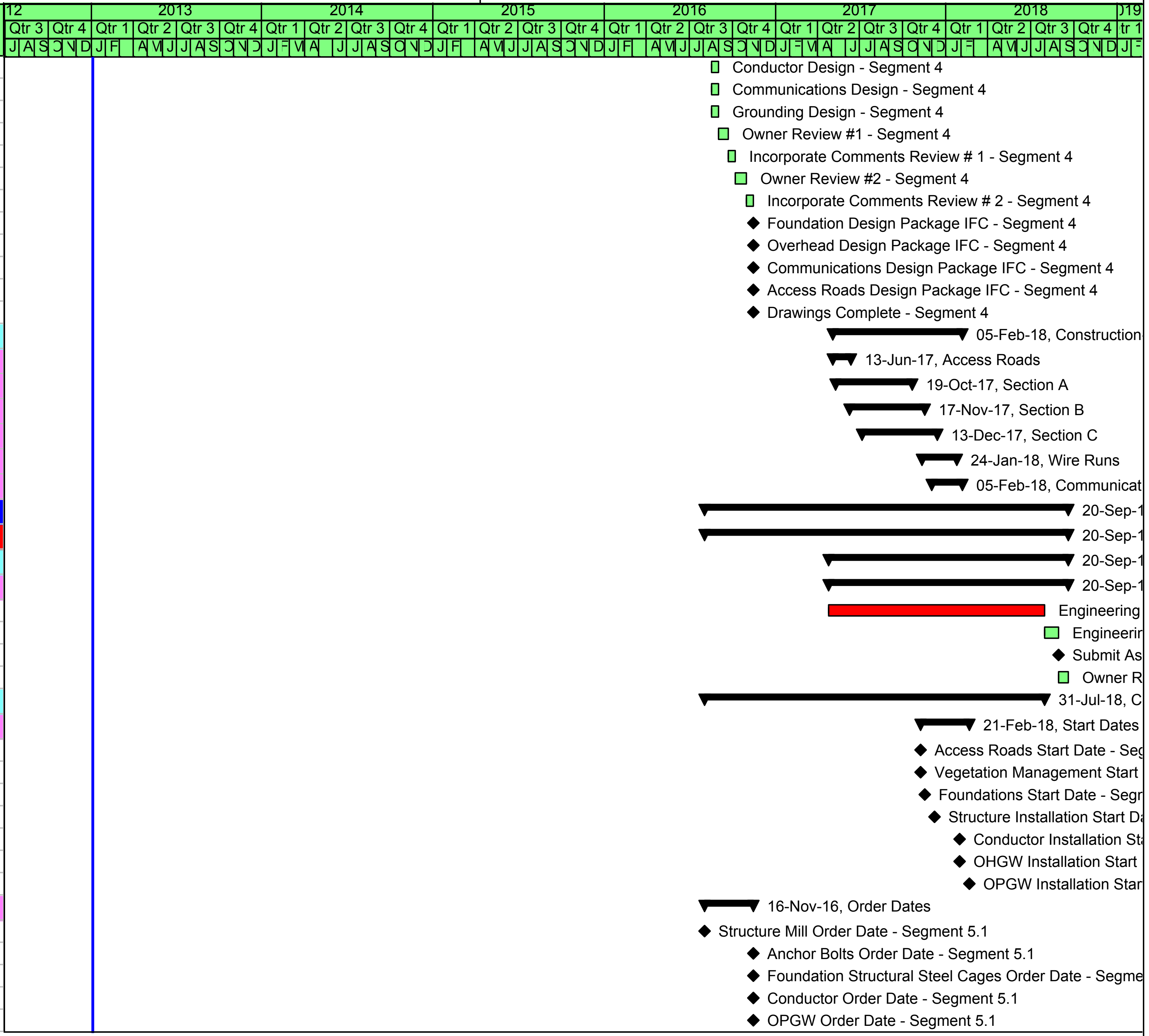
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S4-ENG-1040	Conductor Design - Segment 4	18-Aug-16	01-Sep-16
S4-ENG-1050	Communications Design - Segment 4	18-Aug-16	01-Sep-16
S4-ENG-1060	Grounding Design - Segment 4	18-Aug-16	01-Sep-16
S4-ENG-1070	Owner Review #1 - Segment 4	01-Sep-16	23-Sep-16
S4-ENG-1080	Incorporate Comments Review # 1 - Segment 4	23-Sep-16	07-Oct-16
S4-ENG-1090	Owner Review #2 - Segment 4	07-Oct-16	31-Oct-16
S4-ENG-1100	Incorporate Comments Review # 2 - Segment 4	31-Oct-16	15-Nov-16
S4-ENG-1120	Foundation Design Package IFC - Segment 4		15-Nov-16
S4-ENG-1130	Overhead Design Package IFC - Segment 4		15-Nov-16
S4-ENG-1140	Communications Design Package IFC - Segment 4		15-Nov-16
S4-ENG-1150	Access Roads Design Package IFC - Segment 4		15-Nov-16
S4-ENG-1160	Drawings Complete - Segment 4		16-Nov-16
Construction-T-Line		03-May-17	05-Feb-18
Access Roads		03-May-17	13-Jun-17
Section A		10-May-17	19-Oct-17
Section B		08-Jun-17	17-Nov-17
Section C		07-Jul-17	13-Dec-17
Wire Runs		09-Nov-17	24-Jan-18
Communications		01-Dec-17	05-Feb-18
Segment 5 White River - Wawa (118km)		04-Aug-16	20-Sep-18
Segment 5.1 (60 kilometers)		04-Aug-16	20-Sep-18
Project Management		26-Apr-17	20-Sep-18
Project Support		26-Apr-17	20-Sep-18
S5.1-ENG-9000	Engineering Construction Support - Segment 5.1	26-Apr-17	31-Jul-18
S5.1-ENG-9010	Engineering As-Builts - Segment 5.1	31-Jul-18	29-Aug-18
S5.1-ENG-9020	Submit As-Builts - Segment 5.1		29-Aug-18
S5.1-ENG-9030	Owner Review As-Builts - Segment 5.1	29-Aug-18	20-Sep-18
Contractor Milestones Segment 5.1		04-Aug-16	31-Jul-18
Start Dates		08-Nov-17	21-Feb-18
S5.1-SD-MS-1010	Access Roads Start Date - Segment 5.1	08-Nov-17	
S5.1-SD-MS-1020	Vegetation Management Start Date - Segment 5.1	08-Nov-17	
S5.1-SD-MS-1030	Foundations Start Date - Segment 5.1	16-Nov-17	
S5.1-SD-MS-1040	Structure Installation Start Date - Segment 5.1	07-Dec-17	
S5.1-SD-MS-1050	Conductor Installation Start Date - Segment 5.1	30-Jan-18	
S5.1-SD-MS-1060	OHGW Installation Start Date - Segment 5.1	30-Jan-18	
S5.1-SD-MS-1070	OPGW Installation Start Date - Segment 5.1	21-Feb-18	
Order Dates		04-Aug-16	16-Nov-16
S5.1-OD-MS-1010	Structure Mill Order Date - Segment 5.1	04-Aug-16	
S5.1-OD-MS-1020	Anchor Bolts Order Date - Segment 5.1	16-Nov-16	
S5.1-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment ...	16-Nov-16	
S5.1-OD-MS-1040	Conductor Order Date - Segment 5.1	16-Nov-16	
S5.1-OD-MS-1050	OPGW Order Date - Segment 5.1	16-Nov-16	



- 🟩 Remaining Level of Effort
- 🟦 Actual Level of Effort
- 🟦 Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ ◆ Milestone
- ▬ % Complete
- ▼▼ Summary

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

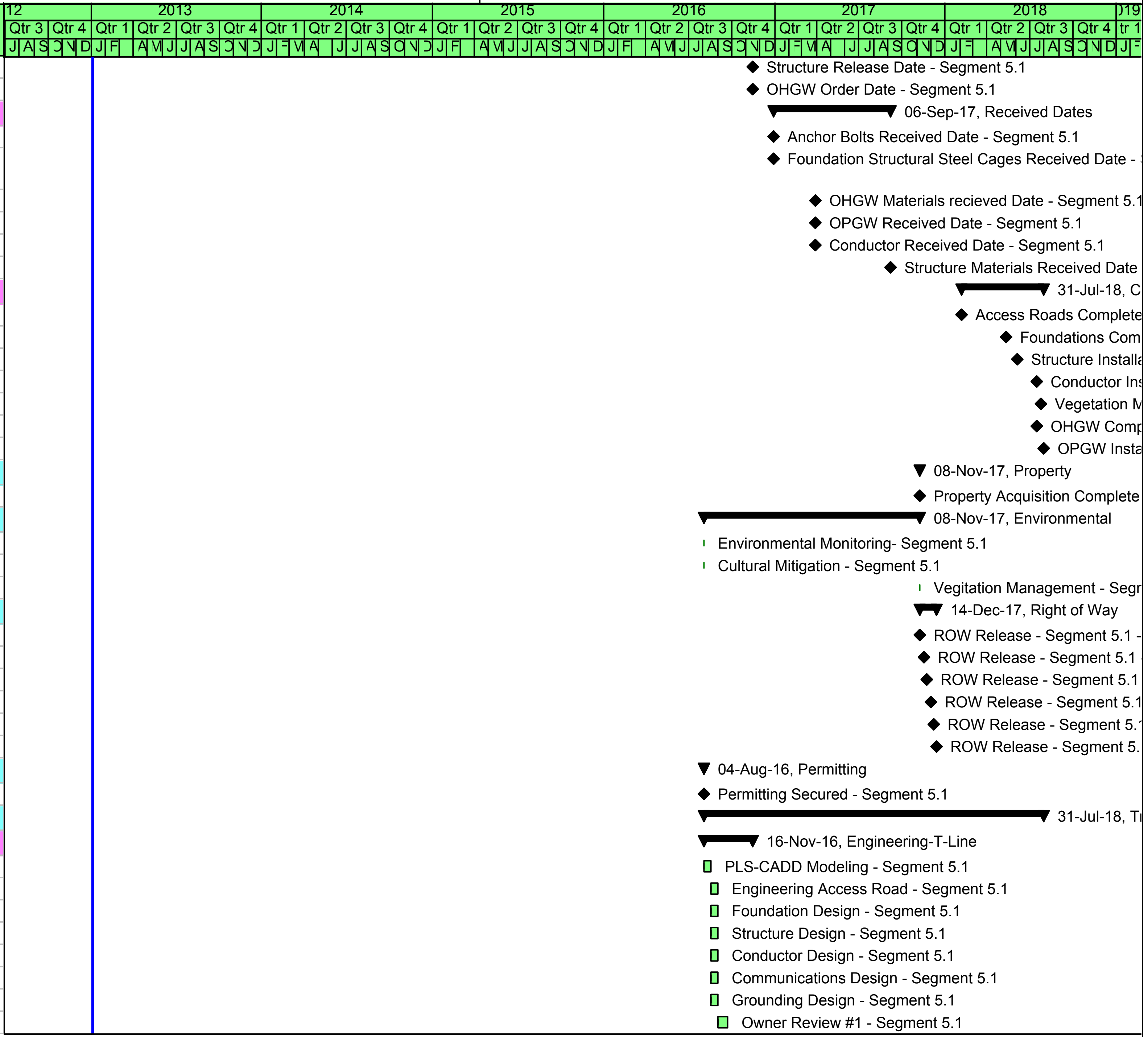
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S5.1-OD-MS-1060	Structure Release Date - Segment 5.1	16-Nov-16	
S5.1-OD-MS-1070	OHGW Order Date - Segment 5.1	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S5.1-RD-MS-1010	Anchor Bolts Received Date - Segment 5.1		30-Dec-16
S5.1-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segment 5.1		30-Dec-16
S5.1-RD-MS-1030	OHGW Materials recieved Date - Segment 5.1		28-Mar-17
S5.1-RD-MS-1040	OPGW Received Date - Segment 5.1		28-Mar-17
S5.1-RD-MS-1050	Conductor Received Date - Segment 5.1		28-Mar-17
S5.1-RD-MS-1060	Structure Materials Received Date - Segment 5.1		06-Sep-17
Completion Dates		06-Feb-18	31-Jul-18
S5.1-CD-MS-1010	Access Roads Complete - Segment 5.1		06-Feb-18
S5.1-CD-MS-1020	Foundations Complete - Segment 5.1		11-May-18
S5.1-CD-MS-1030	Structure Installation Complete - Segment 5.1		04-Jun-18
S5.1-CD-MS-1040	Conductor Installation Complete - Segment 5.1		17-Jul-18
S5.1-CD-MS-1050	Vegetation Management Complete - Segment 5.1		24-Jul-18
S5.1-CD-MS-1060	OHGW Complete - Segment 5.1		17-Jul-18
S5.1-CD-MS-1070	OPGW Installation Complete - Segment 5.1		31-Jul-18
Property		08-Nov-17	08-Nov-17
S5.1-PRP-1000	Property Acquisition Complete - Segment 5.1		08-Nov-17
Environmental		04-Aug-16	08-Nov-17
S5.1-ENV-1000	Environmental Monitoring- Segment 5.1	04-Aug-16	04-Aug-16
S5.1-ENV-1010	Cultural Mitigation - Segment 5.1	04-Aug-16	04-Aug-16
S5.1-ENV-1020	Vegitation Management - Segment 5.1	08-Nov-17	08-Nov-17
Right of Way		08-Nov-17	14-Dec-17
S5.1-ROW-1000	ROW Release - Segment 5.1 - A	08-Nov-17	
S5.1-ROW-1010	ROW Release - Segment 5.1 - B	16-Nov-17	
S5.1-ROW-1020	ROW Release - Segment 5.1 - C	23-Nov-17	
S5.1-ROW-1030	ROW Release - Segment 5.1 - D	30-Nov-17	
S5.1-ROW-1040	ROW Release - Segment 5.1 - E	07-Dec-17	
S5.1-ROW-1050	ROW Release - Segment 5.1 - F	14-Dec-17	
Permitting		04-Aug-16	04-Aug-16
S5.1-PMT-1000	Permitting Secured - Segment 5.1		04-Aug-16
Transmission Lines		04-Aug-16	31-Jul-18
Engineering-T-Line		04-Aug-16	16-Nov-16
S5.1-ENG-1000	PLS-CADD Modeling - Segment 5.1	04-Aug-16	18-Aug-16
S5.1-ENG-1010	Engineering Access Road - Segment 5.1	18-Aug-16	01-Sep-16
S5.1-ENG-1020	Foundation Design - Segment 5.1	18-Aug-16	01-Sep-16
S5.1-ENG-1030	Structure Design - Segment 5.1	18-Aug-16	01-Sep-16
S5.1-ENG-1040	Conductor Design - Segment 5.1	18-Aug-16	01-Sep-16
S5.1-ENG-1050	Communications Design - Segment 5.1	18-Aug-16	01-Sep-16
S5.1-ENG-1060	Grounding Design - Segment 5.1	18-Aug-16	01-Sep-16
S5.1-ENG-1070	Owner Review #1 - Segment 5.1	01-Sep-16	23-Sep-16



🟩 Remaining Level of Effort

▬ % Complete

🟦 Actual Level of Effort

▼ Summary

🟦 Actual Work

🟩 Remaining Work

🟥 Critical Remaining Work

◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

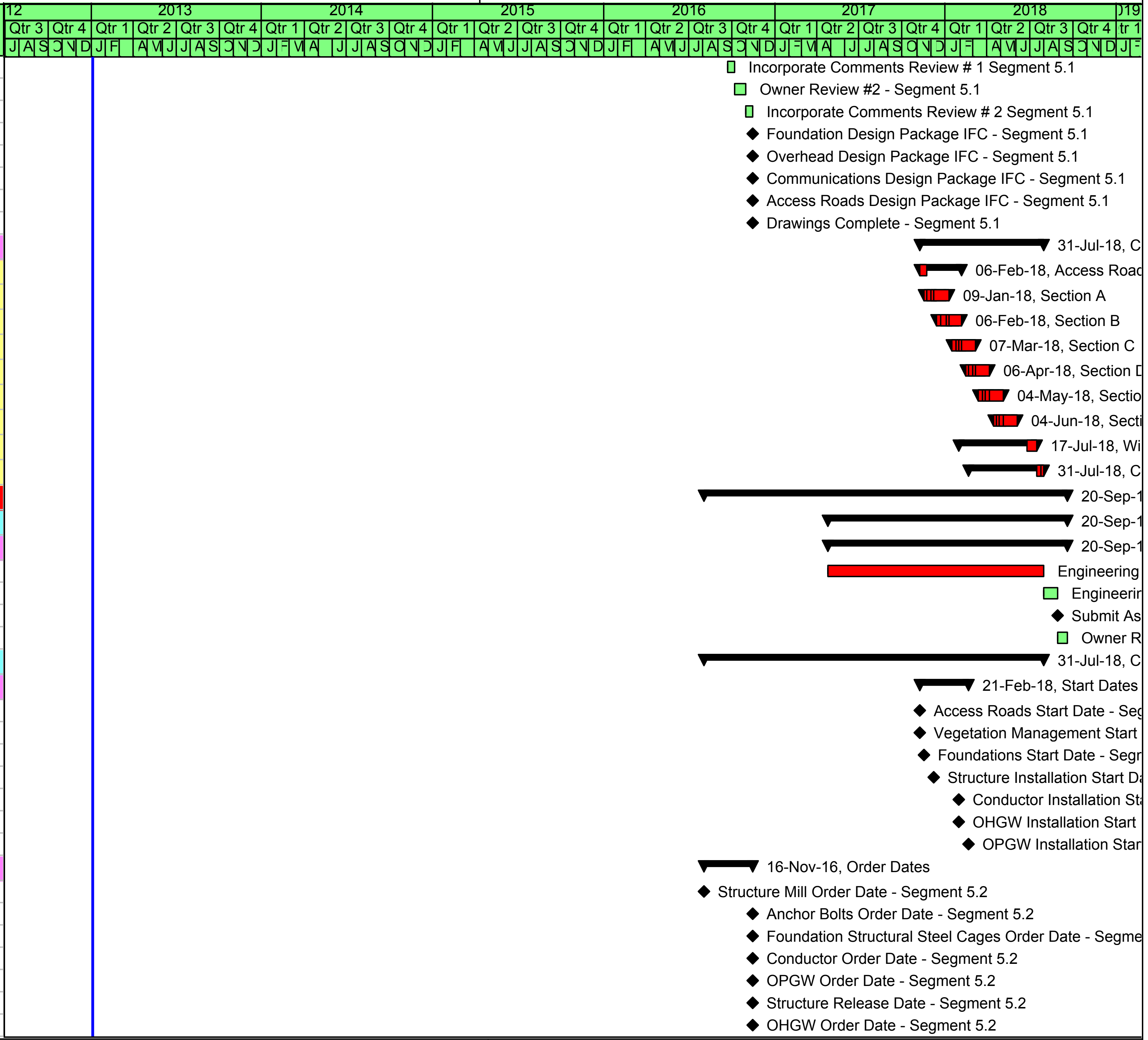
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S5.1-ENG-1080	Incorporate Comments Review # 1 Segment 5.1	23-Sep-16	07-Oct-16
S5.1-ENG-1090	Owner Review #2 - Segment 5.1	07-Oct-16	31-Oct-16
S5.1-ENG-1100	Incorporate Comments Review # 2 Segment 5.1	31-Oct-16	15-Nov-16
S5.1-ENG-1120	Foundation Design Package IFC - Segment 5.1		15-Nov-16
S5.1-ENG-1130	Overhead Design Package IFC - Segment 5.1		15-Nov-16
S5.1-ENG-1140	Communications Design Package IFC - Segment 5.1		15-Nov-16
S5.1-ENG-1150	Access Roads Design Package IFC - Segment 5.1		15-Nov-16
S5.1-ENG-1160	Drawings Complete - Segment 5.1		16-Nov-16
Construction-T-Line		08-Nov-17	31-Jul-18
Access Roads		08-Nov-17	06-Feb-18
Section A		16-Nov-17	09-Jan-18
Section B		14-Dec-17	06-Feb-18
Section C		16-Jan-18	07-Mar-18
Section D		13-Feb-18	06-Apr-18
Section E		14-Mar-18	04-May-18
Section F		13-Apr-18	04-Jun-18
Wire Runs		30-Jan-18	17-Jul-18
Communications		21-Feb-18	31-Jul-18
Segment 5.2 (58 kilometers)		04-Aug-16	20-Sep-18
Project Management		26-Apr-17	20-Sep-18
Project Support		26-Apr-17	20-Sep-18
S5.2-ENG-9000	Engineering Construction Support - Segment 5.2	26-Apr-17	31-Jul-18
S5.2-ENG-9010	Engineering As-Builts - Segment 5.2	31-Jul-18	29-Aug-18
S5.2-ENG-9020	Submit As-Builts - Segment 5.2		29-Aug-18
S5.2-ENG-9030	Owner Review As-Builts - Segment 5.2	29-Aug-18	20-Sep-18
Contractor Milestones Segment 5.2		04-Aug-16	31-Jul-18
Start Dates		08-Nov-17	21-Feb-18
S5.2-SD-MS-1010	Access Roads Start Date - Segment 5.2	08-Nov-17	
S5.2-SD-MS-1020	Vegetation Management Start Date - Segment 5.2	08-Nov-17	
S5.2-SD-MS-1030	Foundations Start Date - Segment 5.2	16-Nov-17	
S5.2-SD-MS-1040	Structure Installation Start Date - Segment 5.2	07-Dec-17	
S5.2-SD-MS-1050	Conductor Installation Start Date - Segment 5.2	30-Jan-18	
S5.2-SD-MS-1060	OHGW Installation Start Date - Segment 5.2	30-Jan-18	
S5.2-SD-MS-1070	OPGW Installation Start Date - Segment 5.2	21-Feb-18	
Order Dates		04-Aug-16	16-Nov-16
S5.2-OD-MS-1010	Structure Mill Order Date - Segment 5.2	04-Aug-16	
S5.2-OD-MS-1020	Anchor Bolts Order Date - Segment 5.2	16-Nov-16	
S5.2-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment ...	16-Nov-16	
S5.2-OD-MS-1040	Conductor Order Date - Segment 5.2	16-Nov-16	
S5.2-OD-MS-1050	OPGW Order Date - Segment 5.2	16-Nov-16	
S5.2-OD-MS-1060	Structure Release Date - Segment 5.2	16-Nov-16	
S5.2-OD-MS-1070	OHGW Order Date - Segment 5.2	16-Nov-16	



🟩 Remaining Level of Effort
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone
▬ % Complete
▼ Summary

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

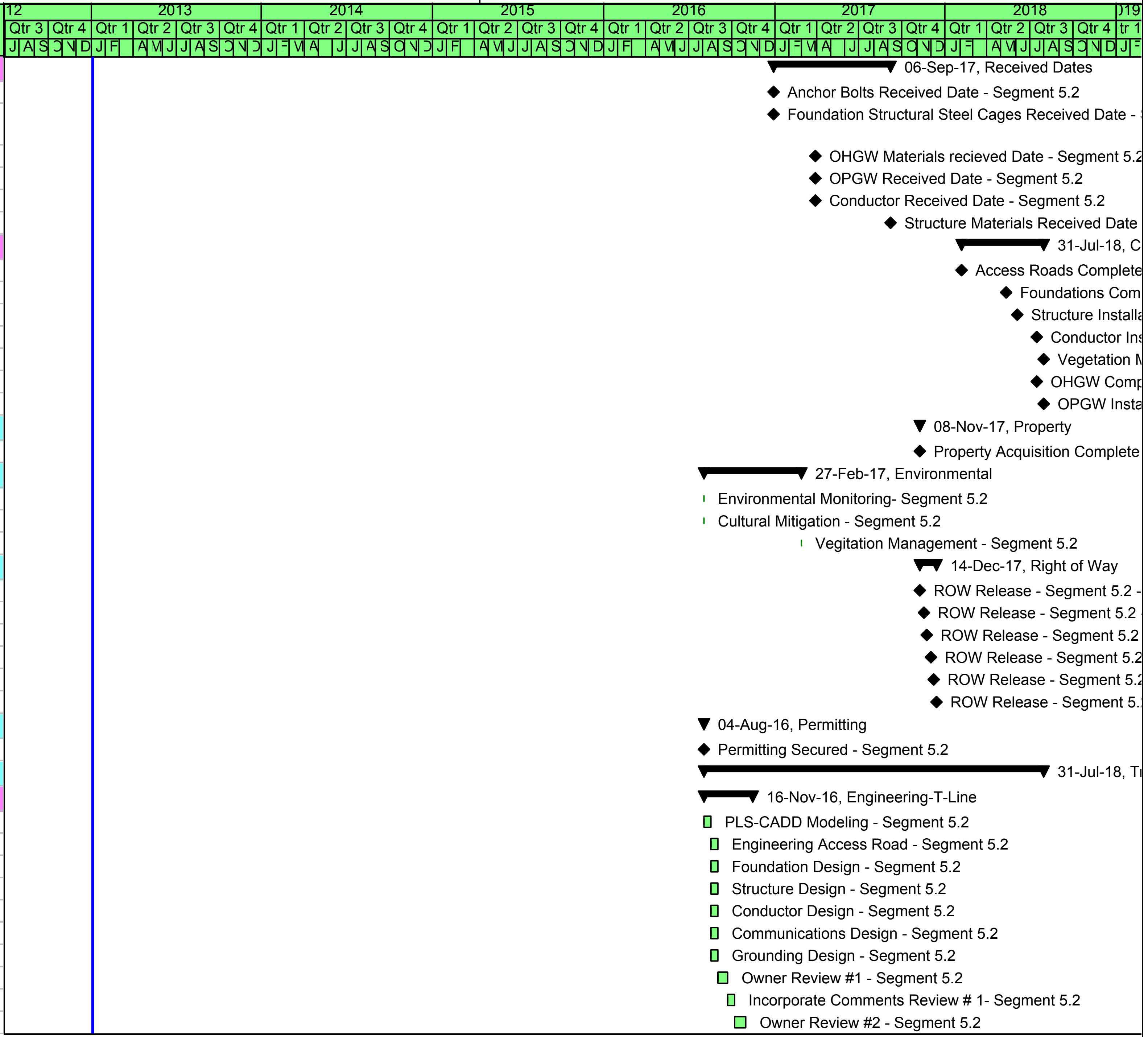
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
Received Dates		30-Dec-16	06-Sep-17
S5.2-RD-MS-1010	Anchor Bolts Received Date - Segment 5.2		30-Dec-16
S5.2-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segment 5.2		30-Dec-16
S5.2-RD-MS-1030	OHGW Materials recieved Date - Segment 5.2		28-Mar-17
S5.2-RD-MS-1040	OPGW Received Date - Segment 5.2		28-Mar-17
S5.2-RD-MS-1050	Conductor Received Date - Segment 5.2		28-Mar-17
S5.2-RD-MS-1060	Structure Materials Received Date - Segment 5.2		06-Sep-17
Completion Dates		06-Feb-18	31-Jul-18
S5.2-CD-MS-1010	Access Roads Complete - Segment 5.2		06-Feb-18
S5.2-CD-MS-1020	Foundations Complete - Segment 5.2		11-May-18
S5.2-CD-MS-1030	Structure Installation Complete - Segment 5.2		04-Jun-18
S5.2-CD-MS-1040	Conductor Installation Complete - Segment 5.2		17-Jul-18
S5.2-CD-MS-1050	Vegetation Management Complete - Segment 5.2		31-Jul-18
S5.2-CD-MS-1060	OHGW Complete - Segment 5.2		17-Jul-18
S5.2-CD-MS-1070	OPGW Installation Complete - Segment 5.2		31-Jul-18
Property		08-Nov-17	08-Nov-17
S5.2-PRP-1000	Property Acquisition Complete - Segment 5.2		08-Nov-17
Environmental		04-Aug-16	27-Feb-17
S5.2-ENV-1010	Environmental Monitoring- Segment 5.2	04-Aug-16	04-Aug-16
S5.2-ENV-1020	Cultural Mitigation - Segment 5.2	04-Aug-16	04-Aug-16
S5.2-ENV-1030	Vegitation Management - Segment 5.2	27-Feb-17	27-Feb-17
Right of Way		08-Nov-17	14-Dec-17
S5.2-ROW-1000	ROW Release - Segment 5.2 - A	08-Nov-17	
S5.2-ROW-1010	ROW Release - Segment 5.2 - B	16-Nov-17	
S5.2-ROW-1020	ROW Release - Segment 5.2 - C	23-Nov-17	
S5.2-ROW-1030	ROW Release - Segment 5.2 - D	30-Nov-17	
S5.2-ROW-1040	ROW Release - Segment 5.2 - E	07-Dec-17	
S5.2-ROW-1050	ROW Release - Segment 5.2 - F	14-Dec-17	
Permitting		04-Aug-16	04-Aug-16
S5.2-PMT-1000	Permitting Secured - Segment 5.2		04-Aug-16
Transmission Lines		04-Aug-16	31-Jul-18
Engineering-T-Line		04-Aug-16	16-Nov-16
S5.2-ENG-1000	PLS-CADD Modeling - Segment 5.2	04-Aug-16	18-Aug-16
S5.2-ENG-1010	Engineering Access Road - Segment 5.2	18-Aug-16	01-Sep-16
S5.2-ENG-1020	Foundation Design - Segment 5.2	18-Aug-16	01-Sep-16
S5.2-ENG-1030	Structure Design - Segment 5.2	18-Aug-16	01-Sep-16
S5.2-ENG-1040	Conductor Design - Segment 5.2	18-Aug-16	01-Sep-16
S5.2-ENG-1050	Communications Design - Segment 5.2	18-Aug-16	01-Sep-16
S5.2-ENG-1060	Grounding Design - Segment 5.2	18-Aug-16	01-Sep-16
S5.2-ENG-1070	Owner Review #1 - Segment 5.2	01-Sep-16	23-Sep-16
S5.2-ENG-1080	Incorporate Comments Review # 1- Segment 5.2	23-Sep-16	07-Oct-16
S5.2-ENG-1090	Owner Review #2 - Segment 5.2	07-Oct-16	31-Oct-16



🟩 Remaining Level of Effort
🟦 Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone
▬ % Complete
▼ Summary

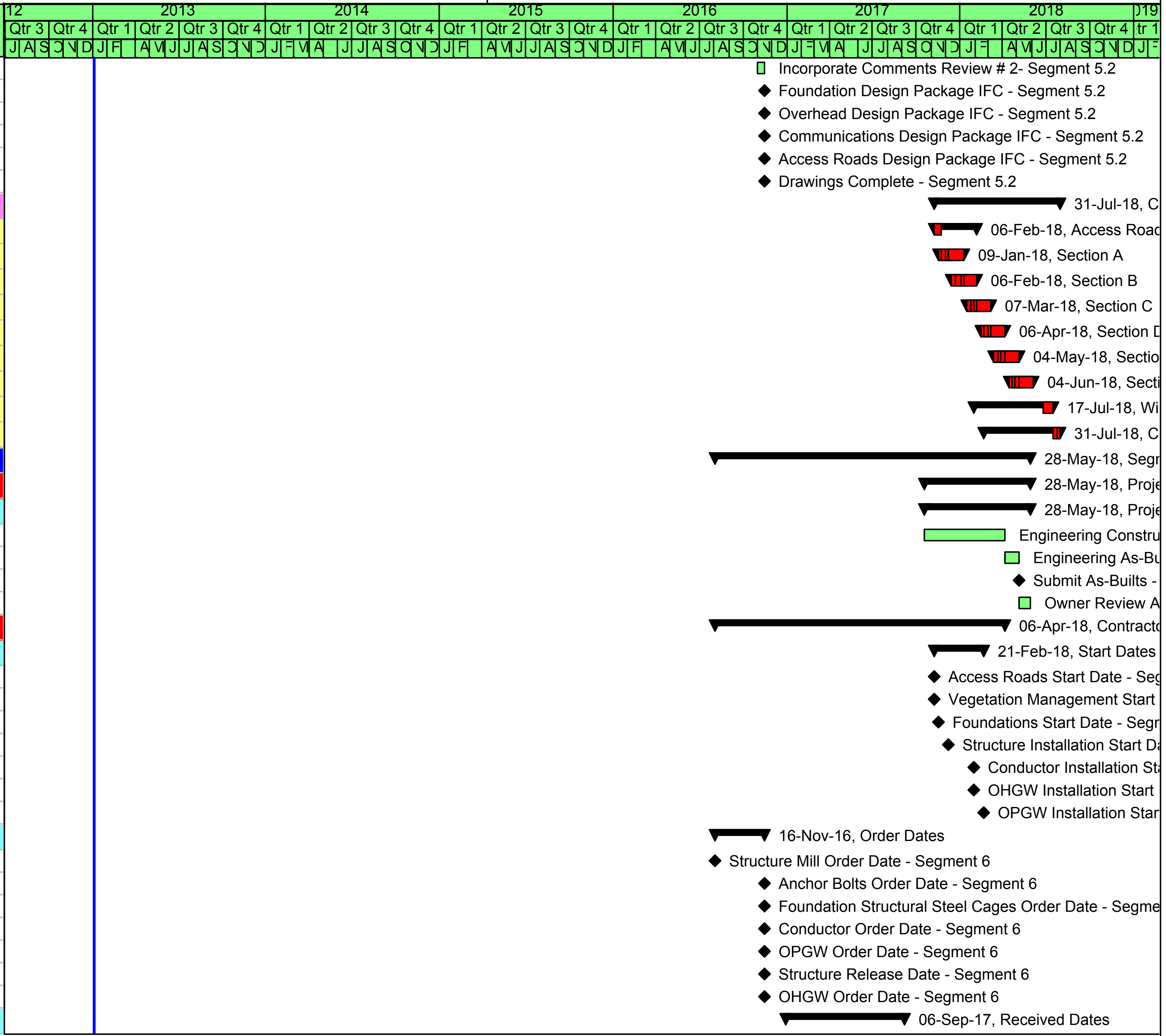
Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

Activity ID	Activity Name	Start	Finish
S5.2-ENG-1100	Incorporate Comments Review # 2- Segment 5.2	31-Oct-16	15-Nov-16
S5.2-ENG-1120	Foundation Design Package IFC - Segment 5.2		15-Nov-16
S5.2-ENG-1130	Overhead Design Package IFC - Segment 5.2		15-Nov-16
S5.2-ENG-1140	Communications Design Package IFC - Segment 5.2		15-Nov-16
S5.2-ENG-1150	Access Roads Design Package IFC - Segment 5.2		15-Nov-16
S5.2-ENG-1160	Drawings Complete - Segment 5.2		16-Nov-16
Construction-T-Line		08-Nov-17	31-Jul-18
Access Roads		08-Nov-17	06-Feb-18
Section A		16-Nov-17	09-Jan-18
Section B		14-Dec-17	06-Feb-18
Section C		16-Jan-18	07-Mar-18
Section D		13-Feb-18	06-Apr-18
Section E		14-Mar-18	04-May-18
Section F		13-Apr-18	04-Jun-18
Wire Runs		30-Jan-18	17-Jul-18
Communications		21-Feb-18	31-Jul-18
Segment 6 Wawa - Substation (20 km)		04-Aug-16	28-May-18
Project Management		18-Oct-17	28-May-18
Project Support		18-Oct-17	28-May-18
S6-ENG-9000	Engineering Construction Support - Segment 6	18-Oct-17	06-Apr-18
S6-ENG-9010	Engineering As-Builts - Segment 6	06-Apr-18	04-May-18
S6-ENG-9020	Submit As-Builts - Segment 6		04-May-18
S6-ENG-9030	Owner Review As-Builts - Segment 6	04-May-18	28-May-18
Contractor Milestones Segment 6		04-Aug-16	06-Apr-18
Start Dates		08-Nov-17	21-Feb-18
S6-SD-MS-1010	Access Roads Start Date - Segment 6	08-Nov-17	
S6-SD-MS-1020	Vegetation Management Start Date - Segment 6	08-Nov-17	
S6-SD-MS-1030	Foundations Start Date - Segment 6	16-Nov-17	
S6-SD-MS-1040	Structure Installation Start Date - Segment 6	07-Dec-17	
S6-SD-MS-1050	Conductor Installation Start Date - Segment 6	30-Jan-18	
S6-SD-MS-1060	OHGW Installation Start Date - Segment 6	30-Jan-18	
S6-SD-MS-1070	OPGW Installation Start Date - Segment 6	21-Feb-18	
Order Dates		04-Aug-16	16-Nov-16
S6-OD-MS-1010	Structure Mill Order Date - Segment 6	04-Aug-16	
S6-OD-MS-1020	Anchor Bolts Order Date - Segment 6	16-Nov-16	
S6-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 6	16-Nov-16	
S6-OD-MS-1040	Conductor Order Date - Segment 6	16-Nov-16	
S6-OD-MS-1050	OPGW Order Date - Segment 6	16-Nov-16	
S6-OD-MS-1060	Structure Release Date - Segment 6	16-Nov-16	
S6-OD-MS-1070	OHGW Order Date - Segment 6	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17



🟩	Remaining Level of Effort	▬	% Complete
🟦	Actual Level of Effort	▼▼	Summary
🟦	Actual Work		
🟩	Remaining Work		
🟥	Critical Remaining Work		
◆ ◆	Milestone		

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

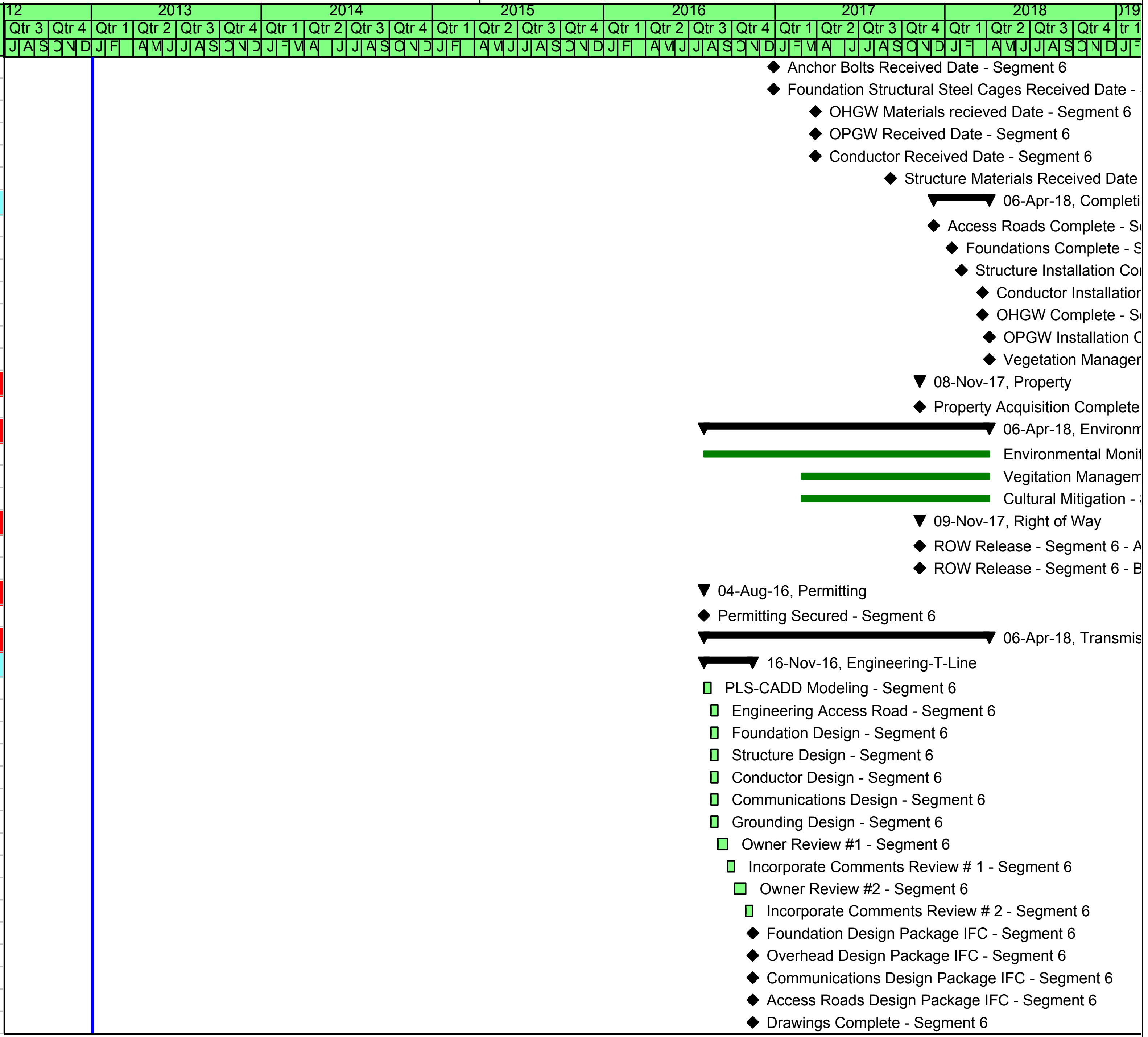
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S6-RD-MS-1010	Anchor Bolts Received Date - Segment 6		30-Dec-16
S6-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segm...		30-Dec-16
S6-RD-MS-1030	OHGW Materials recieved Date - Segment 6		28-Mar-17
S6-RD-MS-1040	OPGW Received Date - Segment 6		28-Mar-17
S6-RD-MS-1050	Conductor Received Date - Segment 6		28-Mar-17
S6-RD-MS-1060	Structure Materials Received Date - Segment 6		06-Sep-17
Completion Dates		07-Dec-17	06-Apr-18
S6-CD-MS-1010	Access Roads Complete - Segment 6		07-Dec-17
S6-CD-MS-1020	Foundations Complete - Segment 6		16-Jan-18
S6-CD-MS-1030	Structure Installation Complete - Segment 6		06-Feb-18
S6-CD-MS-1040	Conductor Installation Complete - Segment 6		21-Mar-18
S6-CD-MS-1050	OHGW Complete - Segment 6		21-Mar-18
S6-CD-MS-1060	OPGW Installation Complete - Segment 6		06-Apr-18
S6-CD-MS-1070	Vegetation Management Complete - Segment 6		06-Apr-18
Property		08-Nov-17	08-Nov-17
S6-PRP-1000	Property Acquisition Complete - Segment 6		08-Nov-17
Environmental		04-Aug-16	06-Apr-18
S6-ENV-1000	Environmental Monitoring- Segment 6	04-Aug-16	06-Apr-18
S6-ENV-1010	Vegitation Management - Segment 6	27-Feb-17	06-Apr-18
S6-ENV-1020	Cultural Mitigation - Segment 6	27-Feb-17	06-Apr-18
Right of Way		08-Nov-17	09-Nov-17
S6-ROW-1000	ROW Release - Segment 6 - A	08-Nov-17	
S6-ROW-1010	ROW Release - Segment 6 - B	09-Nov-17	
Permitting		04-Aug-16	04-Aug-16
S6-PMT-1000	Permitting Secured - Segment 6		04-Aug-16
Transmission Lines		04-Aug-16	06-Apr-18
Engineering-T-Line		04-Aug-16	16-Nov-16
S6-ENG-1000	PLS-CADD Modeling - Segment 6	04-Aug-16	18-Aug-16
S6-ENG-1010	Engineering Access Road - Segment 6	18-Aug-16	01-Sep-16
S6-ENG-1020	Foundation Design - Segment 6	18-Aug-16	01-Sep-16
S6-ENG-1030	Structure Design - Segment 6	18-Aug-16	01-Sep-16
S6-ENG-1040	Conductor Design - Segment 6	18-Aug-16	01-Sep-16
S6-ENG-1050	Communications Design - Segment 6	18-Aug-16	01-Sep-16
S6-ENG-1060	Grounding Design - Segment 6	18-Aug-16	01-Sep-16
S6-ENG-1070	Owner Review #1 - Segment 6	01-Sep-16	23-Sep-16
S6-ENG-1080	Incorporate Comments Review # 1 - Segment 6	23-Sep-16	07-Oct-16
S6-ENG-1090	Owner Review #2 - Segment 6	07-Oct-16	31-Oct-16
S6-ENG-1100	Incorporate Comments Review # 2 - Segment 6	31-Oct-16	15-Nov-16
S6-ENG-1120	Foundation Design Package IFC - Segment 6		15-Nov-16
S6-ENG-1130	Overhead Design Package IFC - Segment 6		15-Nov-16
S6-ENG-1140	Communications Design Package IFC - Segment 6		15-Nov-16
S6-ENG-1150	Access Roads Design Package IFC - Segment 6		15-Nov-16
S6-ENG-1160	Drawings Complete - Segment 6		16-Nov-16



Remaining Level of Effort
Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone
% Complete
Summary

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

Page 16 of 17 Pages

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

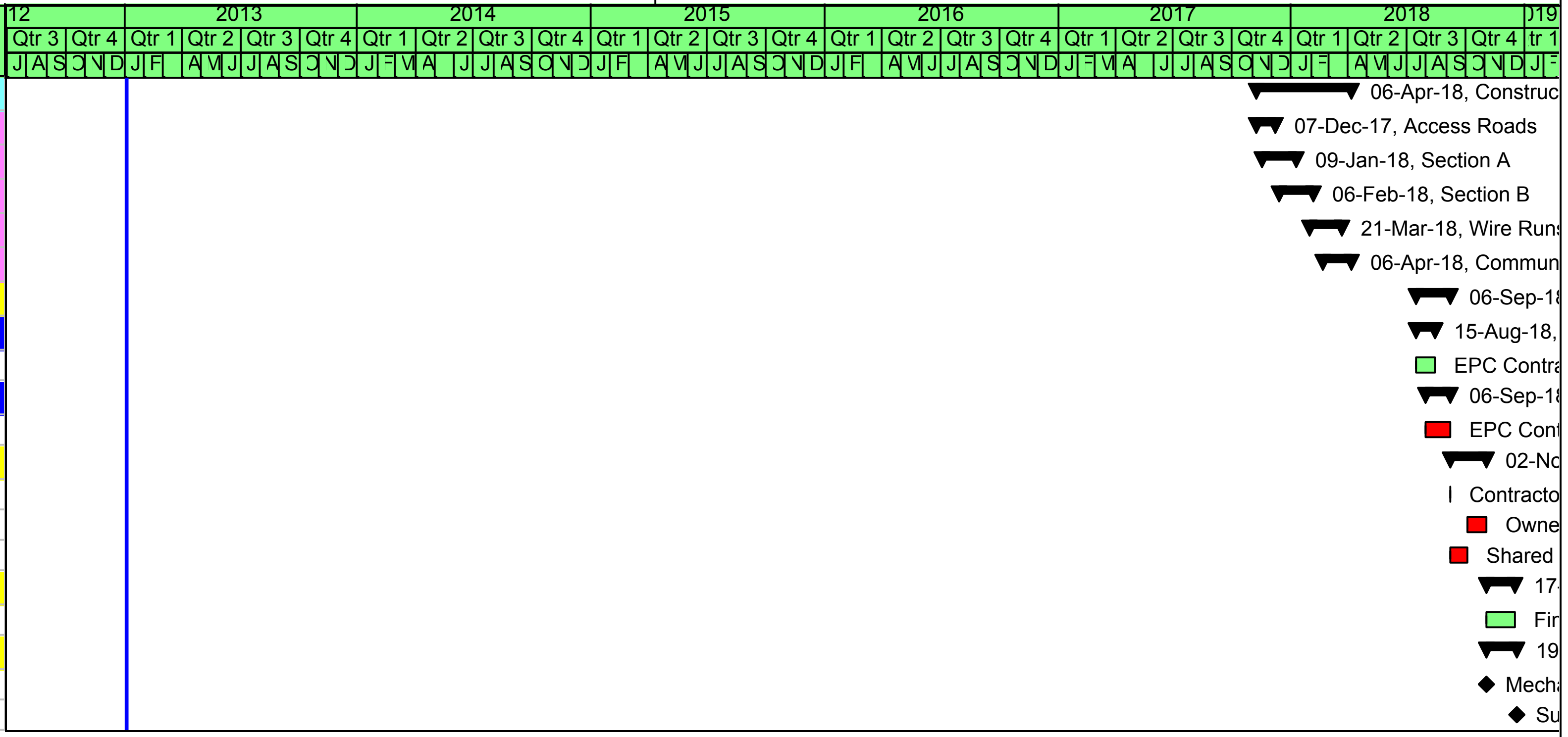
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
Construction-T-Line		08-Nov-17	06-Apr-18
Access Roads		08-Nov-17	07-Dec-17
Section A		16-Nov-17	09-Jan-18
Section B		14-Dec-17	06-Feb-18
Wire Runs		30-Jan-18	21-Mar-18
Communications		21-Feb-18	06-Apr-18
Testing & Commissioning		17-Jul-18	06-Sep-18
Conductors		17-Jul-18	15-Aug-18
CON-1000	EPC Contractor Testing - Conductors	17-Jul-18	15-Aug-18
Communications		31-Jul-18	06-Sep-18
COM-1000	EPC Contractor Testing - Communications	31-Jul-18	06-Sep-18
Float		06-Sep-18	02-Nov-18
CF-1000	Contractor Float	06-Sep-18	06-Sep-18
OF-1000	Owner Float	04-Oct-18	02-Nov-18
SF-1000	Shared Float	06-Sep-18	04-Oct-18
Final End to End Testing		02-Nov-18	17-Dec-18
FT-1000	Final End to End Testing Owner	02-Nov-18	17-Dec-18
Completion Dates		02-Nov-18	19-Dec-18
MC-1000	Mechanical Completion		02-Nov-18
SC-1000	Substantial Completion		19-Dec-18



🟩 Remaining Level of Effort
▬ % Complete
🟦 Actual Level of Effort
▬ Summary
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filter: Hide Development.

Layout: MAT Construction Layout Rollup

TAB N-3-2

Construction Phase – Milestones

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

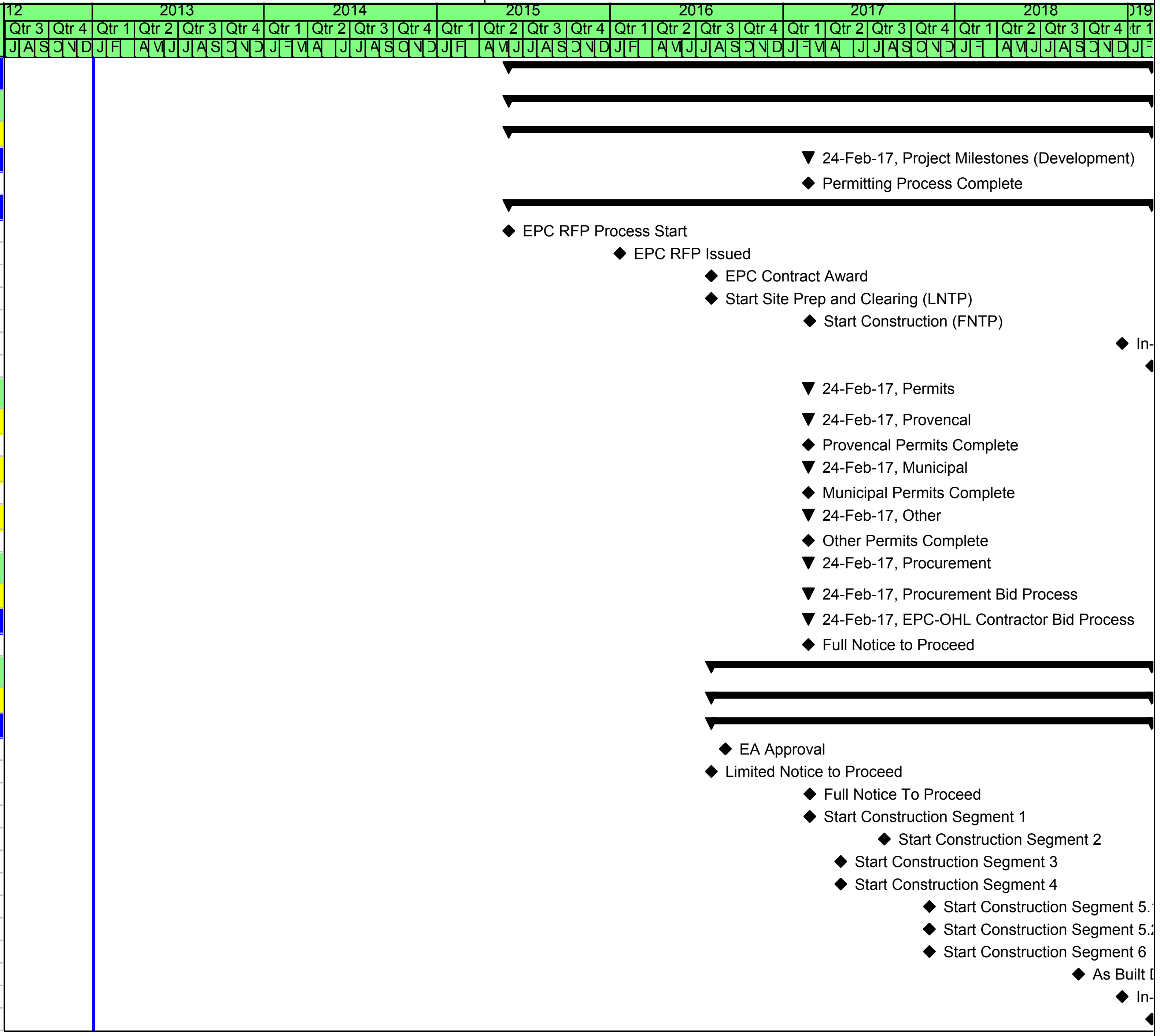
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
E-W Tie - 12-05-12 OEB Post Bid		01-Jun-15	20-Feb-19
Project Management		01-Jun-15	20-Feb-19
Project Milestones		01-Jun-15	20-Feb-19
Project Milestones (Development)		24-Feb-17	24-Feb-17
A2470	Permitting Process Complete		24-Feb-17
Project Milestones (Construction)		01-Jun-15	20-Feb-19
A2480	EPC RFP Process Start	01-Jun-15	
A2490	EPC RFP Issued	21-Jan-16	
A2500	EPC Contract Award		03-Aug-16
A2510	Start Site Prep and Clearing (LNTP)	04-Aug-16	
A2520	Start Construction (FNTP)	27-Feb-17	
A2530	In-Service Date		19-Dec-18
A2540	Project Completion		20-Feb-19
Permits		24-Feb-17	24-Feb-17
Provencal		24-Feb-17	24-Feb-17
A63010	Provencal Permits Complete		24-Feb-17
Municipal		24-Feb-17	24-Feb-17
A63030	Municipal Permits Complete		24-Feb-17
Other		24-Feb-17	24-Feb-17
A63040	Other Permits Complete		24-Feb-17
Procurement		24-Feb-17	24-Feb-17
Procurement Bid Process		24-Feb-17	24-Feb-17
EPC-OHL Contractor Bid Process		24-Feb-17	24-Feb-17
EPC-PR-1550	Full Notice to Proceed		24-Feb-17
EPC Construction		04-Aug-16	20-Feb-19
Transmission Lines Construction		04-Aug-16	20-Feb-19
Project Milestones		04-Aug-16	20-Feb-19
PRJ-MS-0000	EA Approval	01-Sep-16	
PRJ-MS-1000	Limited Notice to Proceed	04-Aug-16	
PRJ-MS-1010	Full Notice To Proceed	27-Feb-17	
PRJ-MS-1020	Start Construction Segment 1	27-Feb-17	
PRJ-MS-1030	Start Construction Segment 2	04-Aug-17	
PRJ-MS-1040	Start Construction Segment 3	03-May-17	
PRJ-MS-1050	Start Construction Segment 4	03-May-17	
PRJ-MS-1060	Start Construction Segment 5.1	08-Nov-17	
PRJ-MS-1070	Start Construction Segment 5.2	08-Nov-17	
PRJ-MS-1080	Start Construction Segment 6	08-Nov-17	
PRJ-MS-1090	As Built Documents Complete		20-Sep-18
PRJ-MS-1100	In-Service Date		19-Dec-18
PRJ-MS-1110	Final Project Completion Date		20-Feb-19



▬ Remaining Level of Effort
▬ Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone
▬ % Complete
▬ Summary

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Development, Milestone.

Layout: MAT Construction Milestone Layout_1

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

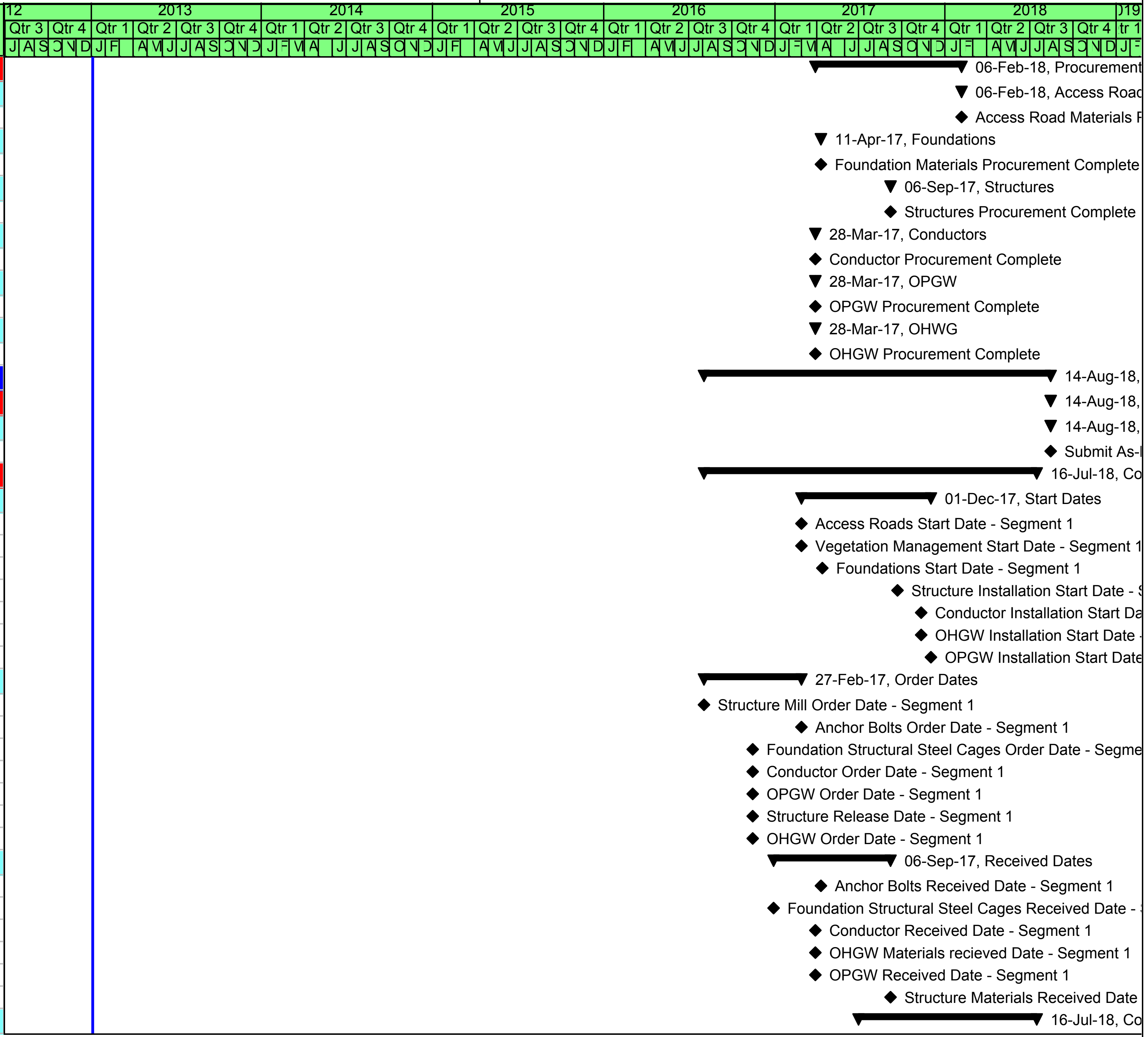
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
Procurement Milestones		28-Mar-17	06-Feb-18
Access Roads		06-Feb-18	06-Feb-18
A60560	Access Road Materials Procurement Complete		06-Feb-18
Foundations		11-Apr-17	11-Apr-17
A60570	Foundation Materials Procurement Complete		11-Apr-17
Structures		06-Sep-17	06-Sep-17
PR190	Structures Procurement Complete		06-Sep-17
Conductors		28-Mar-17	28-Mar-17
PR320	Conductor Procurement Complete		28-Mar-17
OPGW		28-Mar-17	28-Mar-17
PR410	OPGW Procurement Complete		28-Mar-17
OHWG		28-Mar-17	28-Mar-17
PR350	OHGW Procurement Complete		28-Mar-17
Segment 1 Thunder Bay - Nipigon River (85 km)		04-Aug-16	14-Aug-18
Project Management		14-Aug-18	14-Aug-18
Project Support		14-Aug-18	14-Aug-18
S1-ENG-9020	Submit As-Builts - Segment 1		14-Aug-18
Contractor Milestones Segment 1		04-Aug-16	16-Jul-18
Start Dates		27-Feb-17	01-Dec-17
S1-SD-MS-1010	Access Roads Start Date - Segment 1	27-Feb-17	
S1-SD-MS-1020	Vegetation Management Start Date - Segment 1	27-Feb-17	
S1-SD-MS-1030	Foundations Start Date - Segment 1	12-Apr-17	
S1-SD-MS-1040	Structure Installation Start Date - Segment 1	20-Sep-17	
S1-SD-MS-1050	Conductor Installation Start Date - Segment 1	09-Nov-17	
S1-SD-MS-1060	OHGW Installation Start Date - Segment 1	09-Nov-17	
S1-SD-MS-1070	OPGW Installation Start Date - Segment 1	01-Dec-17	
Order Dates		04-Aug-16	27-Feb-17
S1-OD-MS-1000	Structure Mill Order Date - Segment 1	04-Aug-16	
S1-OD-MS-1010	Anchor Bolts Order Date - Segment 1	27-Feb-17	
S1-OD-MS-1020	Foundation Structural Steel Cages Order Date - Segment 1	16-Nov-16	
S1-OD-MS-1030	Conductor Order Date - Segment 1	16-Nov-16	
S1-OD-MS-1040	OPGW Order Date - Segment 1	16-Nov-16	
S1-OD-MS-1050	Structure Release Date - Segment 1	16-Nov-16	
S1-OD-MS-1060	OHGW Order Date - Segment 1	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S1-RD-MS-1010	Anchor Bolts Received Date - Segment 1		11-Apr-17
S1-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segm...		30-Dec-16
S1-RD-MS-1030	Conductor Received Date - Segment 1		28-Mar-17
S1-RD-MS-1040	OHGW Materials recieved Date - Segment 1		28-Mar-17
S1-RD-MS-1050	OPGW Received Date - Segment 1		28-Mar-17
S1-RD-MS-1060	Structure Materials Received Date - Segment 1 (40weeks)		06-Sep-17
Completion Dates		29-Jun-17	16-Jul-18



Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
◆ Milestone
% Complete
Summary

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Development, Milestone.

Layout: MAT Construction Milestone Layout_1

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

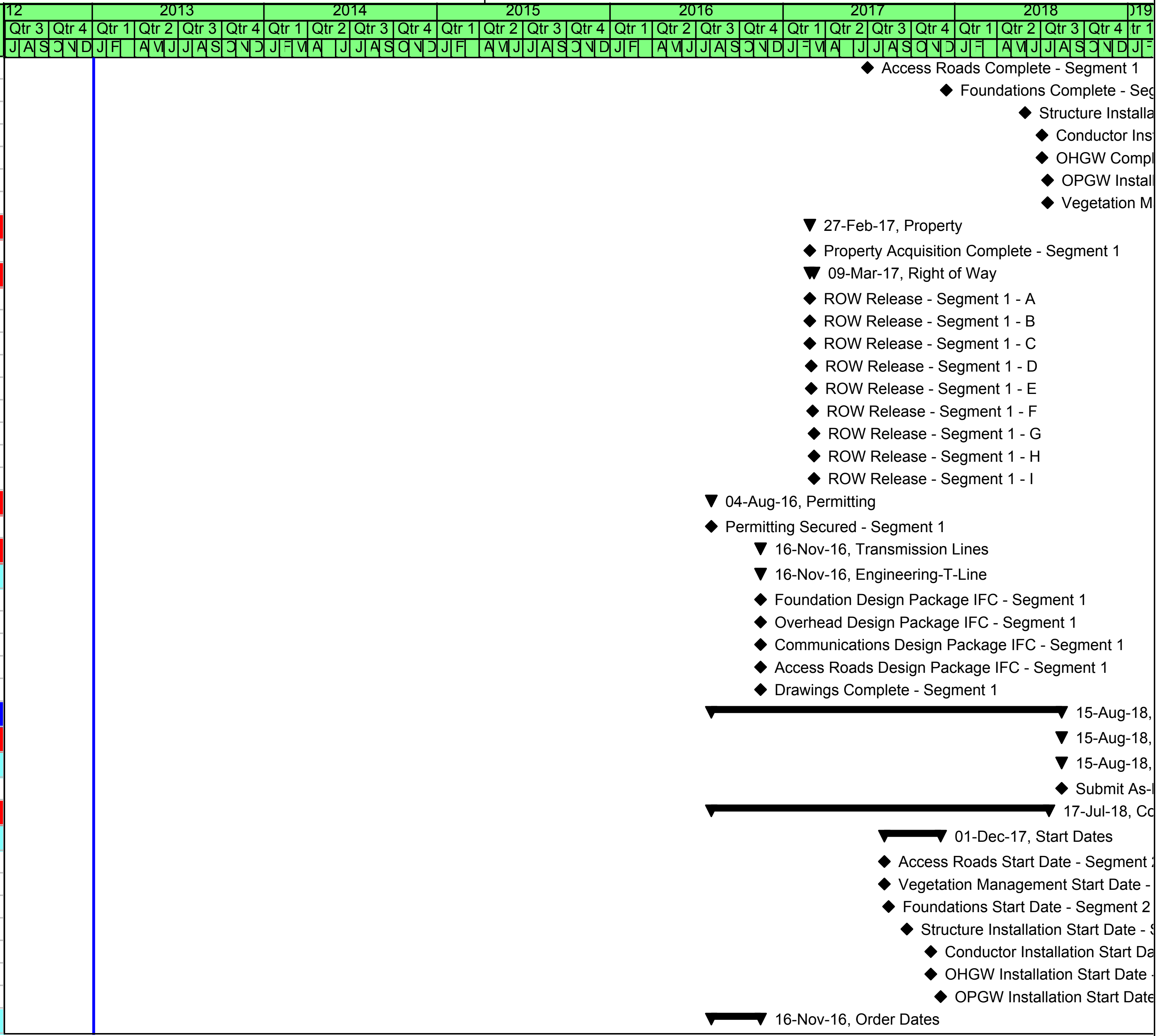
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S1-CD-MS-1010	Access Roads Complete - Segment 1		29-Jun-17
S1-CD-MS-1020	Foundations Complete - Segment 1		13-Dec-17
S1-CD-MS-1030	Structure Installation Complete - Segment 1		29-May-18
S1-CD-MS-1040	Conductor Installation Complete - Segment 1		04-Jul-18
S1-CD-MS-1050	OHGW Complete - Segment 1		04-Jul-18
S1-CD-MS-1060	OPGW Installation Complete - Segment 1		16-Jul-18
S1-CD-MS-1070	Vegetation Management Complete - Segment 1		16-Jul-18
Property		27-Feb-17	27-Feb-17
S1-PRP-1000	Property Acquisition Complete - Segment 1		27-Feb-17
Right of Way		27-Feb-17	09-Mar-17
ROW-1A	ROW Release - Segment 1 - A	27-Feb-17	
ROW-1B	ROW Release - Segment 1 - B	28-Feb-17	
ROW-1C	ROW Release - Segment 1 - C	01-Mar-17	
ROW-1D	ROW Release - Segment 1 - D	02-Mar-17	
ROW-1E	ROW Release - Segment 1 - E	03-Mar-17	
ROW-1F	ROW Release - Segment 1 - F	06-Mar-17	
ROW-1G	ROW Release - Segment 1 - G	07-Mar-17	
ROW-1H	ROW Release - Segment 1 - H	08-Mar-17	
ROW-1I	ROW Release - Segment 1 - I	09-Mar-17	
Permitting		04-Aug-16	04-Aug-16
S1-PMT-1000	Permitting Secured - Segment 1		04-Aug-16
Transmission Lines		15-Nov-16	16-Nov-16
Engineering-T-Line		15-Nov-16	16-Nov-16
S1-ENG-1120	Foundation Design Package IFC - Segment 1		15-Nov-16
S1-ENG-1130	Overhead Design Package IFC - Segment 1		15-Nov-16
S1-ENG-1140	Communications Design Package IFC - Segment 1		15-Nov-16
S1-ENG-1150	Access Roads Design Package IFC - Segment 1		15-Nov-16
S1-ENG-1160	Drawings Complete - Segment 1		16-Nov-16
Segment 2 Nipigon River - Terrace Bay (86 km)		04-Aug-16	15-Aug-18
Project Management		15-Aug-18	15-Aug-18
Project Support		15-Aug-18	15-Aug-18
S2-ENG-9020	Submit As-Builts - Segment 2		15-Aug-18
Contractor Milestones Segment 2		04-Aug-16	17-Jul-18
Start Dates		04-Aug-17	01-Dec-17
S2-SD-MS-1010	Access Roads Start Date - Segment 2	04-Aug-17	
S2-SD-MS-1020	Vegetation Management Start Date - Segment 2	04-Aug-17	
S2-SD-MS-1030	Foundations Start Date - Segment 2	14-Aug-17	
S2-SD-MS-1040	Structure Installation Start Date - Segment 2	20-Sep-17	
S2-SD-MS-1050	Conductor Installation Start Date - Segment 2	09-Nov-17	
S2-SD-MS-1060	OHGW Installation Start Date - Segment 2	09-Nov-17	
S2-SD-MS-1070	OPGW Installation Start Date - Segment 2	01-Dec-17	
Order Dates		04-Aug-16	16-Nov-16



🟩 Remaining Level of Effort	▬ % Complete
▬ Actual Level of Effort	▼ Summary
🟦 Actual Work	
🟩 Remaining Work	
🟥 Critical Remaining Work	
◆ ◆ Milestone	

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Development, Milestone.

Layout: MAT Construction Milestone Layout_1

MIDAMERICAN
TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

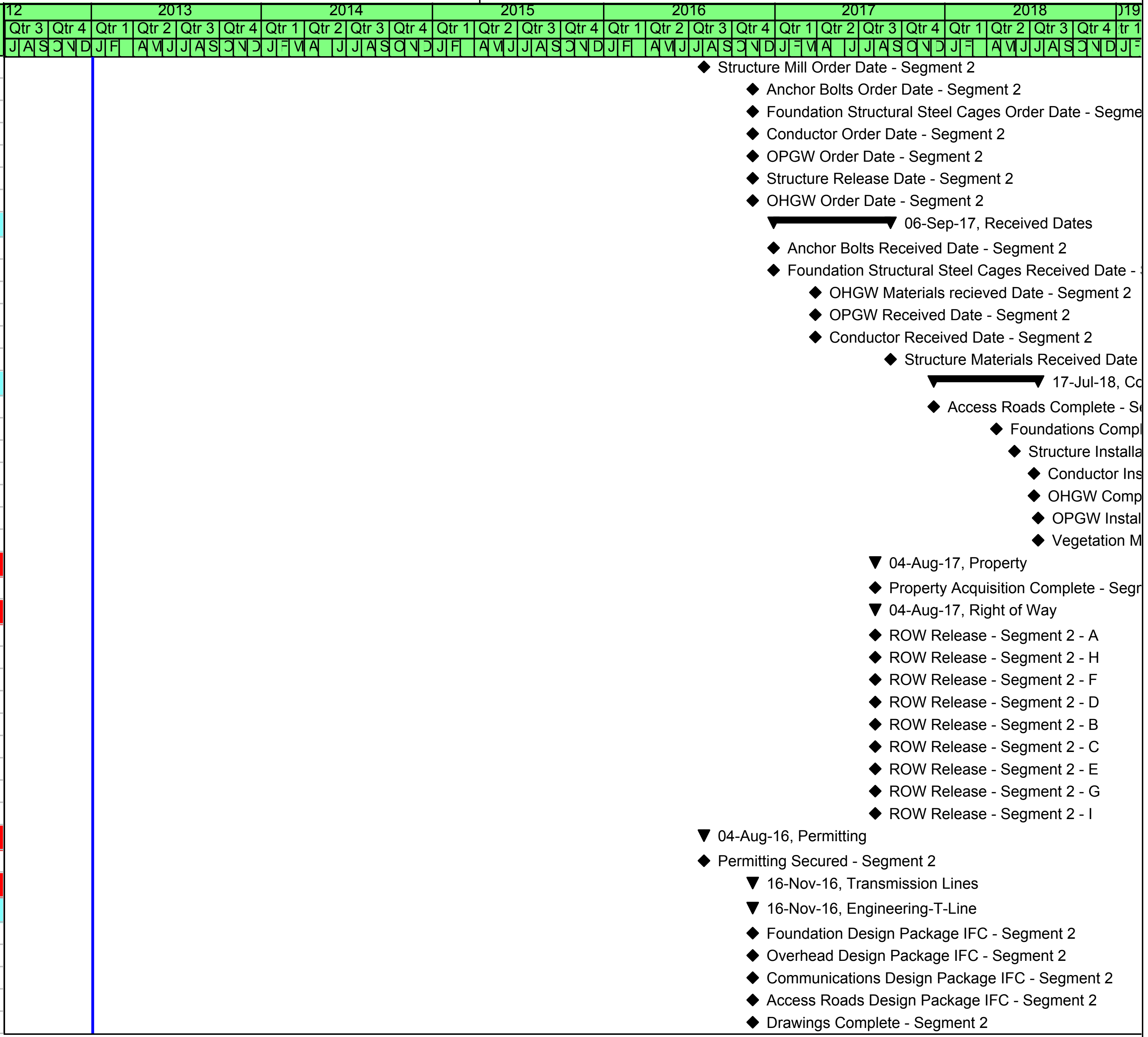
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S2-OD-MS-1010	Structure Mill Order Date - Segment 2	04-Aug-16	
S2-OD-MS-1020	Anchor Bolts Order Date - Segment 2	16-Nov-16	
S2-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 2	16-Nov-16	
S2-OD-MS-1040	Conductor Order Date - Segment 2	16-Nov-16	
S2-OD-MS-1050	OPGW Order Date - Segment 2	16-Nov-16	
S2-OD-MS-1060	Structure Release Date - Segment 2	16-Nov-16	
S2-OD-MS-1070	OHGW Order Date - Segment 2	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S2-RD-MS-1010	Anchor Bolts Received Date - Segment 2		30-Dec-16
S2-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segm...		30-Dec-16
S2-RD-MS-1030	OHGW Materials recieved Date - Segment 2		28-Mar-17
S2-RD-MS-1040	OPGW Received Date - Segment 2		28-Mar-17
S2-RD-MS-1050	Conductor Received Date - Segment 2		28-Mar-17
S2-RD-MS-1060	Structure Materials Received Date - Segment 2		06-Sep-17
Completion Dates		08-Dec-17	17-Jul-18
S2-CD-MS-1010	Access Roads Complete - Segment 2		08-Dec-17
S2-CD-MS-1020	Foundations Complete - Segment 2		20-Apr-18
S2-CD-MS-1030	Structure Installation Complete - Segment 2		29-May-18
S2-CD-MS-1040	Conductor Installation Complete - Segment 2		09-Jul-18
S2-CD-MS-1050	OHGW Complete - Segment 2		09-Jul-18
S2-CD-MS-1060	OPGW Installation Complete - Segment 2		17-Jul-18
S2-CD-MS-1070	Vegetation Management Complete - Segment 2		17-Jul-18
Property		04-Aug-17	04-Aug-17
S2-PRP-1000	Property Acquisition Complete - Segment 2		04-Aug-17
Right of Way		04-Aug-17	04-Aug-17
S2-ROW-1000	ROW Release - Segment 2 - A	04-Aug-17	
S2-ROW-1010	ROW Release - Segment 2 - H	04-Aug-17	
S2-ROW-1020	ROW Release - Segment 2 - F	04-Aug-17	
S2-ROW-1030	ROW Release - Segment 2 - D	04-Aug-17	
S2-ROW-1040	ROW Release - Segment 2 - B	04-Aug-17	
S2-ROW-1050	ROW Release - Segment 2 - C	04-Aug-17	
S2-ROW-1060	ROW Release - Segment 2 - E	04-Aug-17	
S2-ROW-1070	ROW Release - Segment 2 - G	04-Aug-17	
S2-ROW-1080	ROW Release - Segment 2 - I	04-Aug-17	
Permitting		04-Aug-16	04-Aug-16
S2-PMT-1000	Permitting Secured - Segment 2		04-Aug-16
Transmission Lines		15-Nov-16	16-Nov-16
Engineering-T-Line		15-Nov-16	16-Nov-16
S2-ENG-1120	Foundation Design Package IFC - Segment 2		15-Nov-16
S2-ENG-1130	Overhead Design Package IFC - Segment 2		15-Nov-16
S2-ENG-1140	Communications Design Package IFC - Segment 2		15-Nov-16
S2-ENG-1150	Access Roads Design Package IFC - Segment 2		15-Nov-16
S2-ENG-1160	Drawings Complete - Segment 2		16-Nov-16



Remaining Level of Effort
Actual Level of Effort
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone
% Complete
Summary

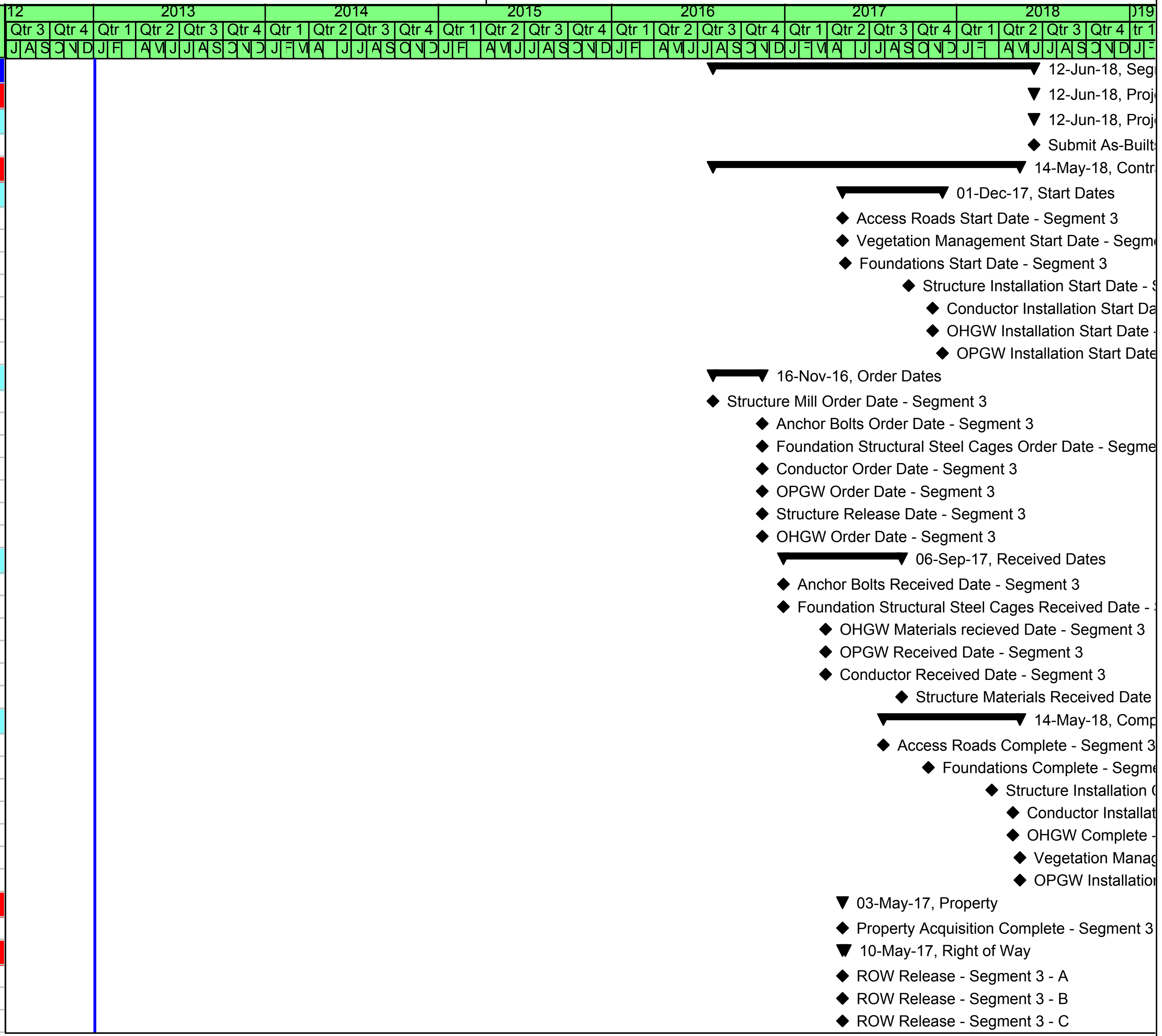
Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Development, Milestone.

Layout: MAT Construction Milestone Layout_1

Activity ID	Activity Name	Start	Finish
Segment 3 Terrace Bay - Marathon (60 km)		04-Aug-16	12-Jun-18
Project Management		12-Jun-18	12-Jun-18
Project Support		12-Jun-18	12-Jun-18
S3-ENG-9020	Submit As-Builts - Segment 3		12-Jun-18
Contractor Milestones Segment 3		04-Aug-16	14-May-18
Start Dates		03-May-17	01-Dec-17
S3-SD-MS-1010	Access Roads Start Date - Segment 3	03-May-17	
S3-SD-MS-1020	Vegetation Management Start Date - Segment 3	03-May-17	
S3-SD-MS-1030	Foundations Start Date - Segment 3	10-May-17	
S3-SD-MS-1040	Structure Installation Start Date - Segment 3	20-Sep-17	
S3-SD-MS-1050	Conductor Installation Start Date - Segment 3	09-Nov-17	
S3-SD-MS-1060	OHGW Installation Start Date - Segment 3	09-Nov-17	
S3-SD-MS-1070	OPGW Installation Start Date - Segment 3	01-Dec-17	
Order Dates		04-Aug-16	16-Nov-16
S3-OD-MS-1010	Structure Mill Order Date - Segment 3	04-Aug-16	
S3-OD-MS-1020	Anchor Bolts Order Date - Segment 3	16-Nov-16	
S3-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 3	16-Nov-16	
S3-OD-MS-1040	Conductor Order Date - Segment 3	16-Nov-16	
S3-OD-MS-1050	OPGW Order Date - Segment 3	16-Nov-16	
S3-OD-MS-1060	Structure Release Date - Segment 3	16-Nov-16	
S3-OD-MS-1070	OHGW Order Date - Segment 3	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S3-RD-MS-1010	Anchor Bolts Received Date - Segment 3		30-Dec-16
S3-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segm...		30-Dec-16
S3-RD-MS-1030	OHGW Materials recieved Date - Segment 3		28-Mar-17
S3-RD-MS-1040	OPGW Received Date - Segment 3		28-Mar-17
S3-RD-MS-1050	Conductor Received Date - Segment 3		28-Mar-17
S3-RD-MS-1060	Structure Materials Received Date - Segment 3		06-Sep-17
Completion Dates		28-Jul-17	14-May-18
S3-CD-MS-1010	Access Roads Complete - Segment 3		28-Jul-17
S3-CD-MS-1020	Foundations Complete - Segment 3		01-Nov-17
S3-CD-MS-1030	Structure Installation Complete - Segment 3		15-Mar-18
S3-CD-MS-1040	Conductor Installation Complete - Segment 3		30-Apr-18
S3-CD-MS-1060	OHGW Complete - Segment 3		30-Apr-18
S3-CD-MS-1070	Vegetation Management Complete - Segment 3		14-May-18
S3-CD-MS-1080	OPGW Installation Complete - Segment 3		14-May-18
Property		03-May-17	03-May-17
A62990	Property Acquisition Complete - Segment 3		03-May-17
Right of Way		03-May-17	10-May-17
S3-ROW-1000	ROW Release - Segment 3 - A	03-May-17	
S3-ROW-1010	ROW Release - Segment 3 - B	04-May-17	
S3-ROW-1020	ROW Release - Segment 3 - C	05-May-17	



🟩	Remaining Level of Effort
🟦	Actual Level of Effort
🟦	Actual Work
🟩	Remaining Work
🟥	Critical Remaining Work
◆ ◆	Milestone
▬	% Complete
▼▬▼	Summary

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Development, Milestone.

Layout: MAT Construction Milestone Layout_1

Activity ID	Activity Name	Start	Finish
S3-ROW-1030	ROW Release - Segment 3 - D	08-May-17	
S3-ROW-1040	ROW Release - Segment 3 - E	09-May-17	
S3-ROW-1050	ROW Release - Segment 3 - F	10-May-17	
Permitting		04-Aug-16	04-Aug-16
S3-PMT-1000	Permitting Secured - Segment 3		04-Aug-16
Transmission Lines		15-Nov-16	16-Nov-16
Engineering-T-Line		15-Nov-16	16-Nov-16
S3-ENG-1120	Foundation Design Package IFC - Segment 3		15-Nov-16
S3-ENG-1130	Overhead Design Package IFC - Segment 3		15-Nov-16
S3-ENG-1140	Communications Design Package IFC - Segment 3		15-Nov-16
S3-ENG-1150	Access Roads Design Package IFC - Segment 3		15-Nov-16
S3-ENG-1160	Drawings Complete - Segment 3		16-Nov-16
Segment 4 Marathon - White River (28 km)		04-Aug-16	06-Mar-18
Project Management		06-Mar-18	06-Mar-18
Project Support		06-Mar-18	06-Mar-18
S4-ENG-9020	Submit As-Builts - Segment 4		06-Mar-18
Contractor Milestones Segment 4		04-Aug-16	05-Feb-18
Start Dates		03-May-17	01-Dec-17
S4-SD-MS-1010	Access Roads Start Date - Segment 4	03-May-17	
S4-SD-MS-1020	Vegetation Management Start Date - Segment 4	03-May-17	
S4-SD-MS-1030	Foundations Start Date - Segment 4	10-May-17	
S4-SD-MS-1040	Structure Installation Start Date - Segment 4	20-Sep-17	
S4-SD-MS-1050	Conductor Installation Start Date - Segment 4	09-Nov-17	
S4-SD-MS-1060	OHGW Installation Start Date - Segment 4	09-Nov-17	
S4-SD-MS-1070	OPGW Installation Start Date - Segment 4	01-Dec-17	
Order Dates		04-Aug-16	16-Nov-16
S4-OD-MS-1010	Structure Mill Order Date - Segment 4	04-Aug-16	
S4-OD-MS-1020	Anchor Bolts Order Date - Segment 4	16-Nov-16	
S4-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 4	16-Nov-16	
S4-OD-MS-1040	Conductor Order Date - Segment 4	16-Nov-16	
S4-OD-MS-1050	OPGW Order Date - Segment 4	16-Nov-16	
S4-OD-MS-1060	Structure Release Date - Segment 4	16-Nov-16	
S4-OD-MS-1070	OHGW Order Date - Segment 4	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S4-RD-MS-1010	Anchor Bolts Received Date - Segment 4		30-Dec-16
S4-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segm...		30-Dec-16
S4-RD-MS-1030	OHGW Materials recieved Date - Segment 4		28-Mar-17
S4-RD-MS-1040	OPGW Received Date - Segment 4		28-Mar-17
S4-RD-MS-1050	Conductor Received Date - Segment 4		28-Mar-17
S4-RD-MS-1060	Structure Materials Received Date - Segment 4		06-Sep-17
Completion Dates		13-Jun-17	05-Feb-18
S4-CD-MS-1010	Access Roads Complete - Segment 4		13-Jun-17

- 🟩 Remaining Level of Effort
- 🟦 Actual Level of Effort
- 🟦 Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ ◆ Milestone
- ▬ % Complete
- ▼▬▼ Summary

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Development, Milestone.

Layout: MAT Construction Milestone Layout_1

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S4-CD-MS-1020	Foundations Complete - Segment 4		02-Aug-17
S4-CD-MS-1030	Structure Installation Complete - Segment 4		13-Dec-17
S4-CD-MS-1040	Conductor Installation Complete - Segment 4		24-Jan-18
S4-CD-MS-1050	OHGW Complete - Segment 4		24-Jan-18
S4-CD-MS-1060	OPGW Installation Complete - Segment 4		05-Feb-18
S4-CD-MS-1070	Vegetation Management Complete - Segment 4		05-Feb-18
Property		03-May-17	03-May-17
S4-PRP-1000	Property Acquisition Complete - Segment 4		03-May-17
Right of Way		03-May-17	05-May-17
S4-ROW-1000	ROW Release - Segment 4 - A	03-May-17	
S4-ROW-1010	ROW Release - Segment 4 - B	04-May-17	
S4-ROW-1020	ROW Release - Segment 4 - C	05-May-17	
Permitting		04-Aug-16	04-Aug-16
S4-PMT-1000	Permitting Secured - Segment 4		04-Aug-16
Transmission Lines		15-Nov-16	16-Nov-16
Engineering-T-Line		15-Nov-16	16-Nov-16
S4-ENG-1120	Foundation Design Package IFC - Segment 4		15-Nov-16
S4-ENG-1130	Overhead Design Package IFC - Segment 4		15-Nov-16
S4-ENG-1140	Communications Design Package IFC - Segment 4		15-Nov-16
S4-ENG-1150	Access Roads Design Package IFC - Segment 4		15-Nov-16
S4-ENG-1160	Drawings Complete - Segment 4		16-Nov-16
Segment 5 White River - Wawa (118km)		04-Aug-16	29-Aug-18
Segment 5.1 (60 kilometers)		04-Aug-16	29-Aug-18
Project Management		29-Aug-18	29-Aug-18
Project Support		29-Aug-18	29-Aug-18
S5.1-ENG-9020	Submit As-Builts - Segment 5.1		29-Aug-18
Contractor Milestones Segment 5.1		04-Aug-16	31-Jul-18
Start Dates		08-Nov-17	21-Feb-18
S5.1-SD-MS-1010	Access Roads Start Date - Segment 5.1	08-Nov-17	
S5.1-SD-MS-1020	Vegetation Management Start Date - Segment 5.1	08-Nov-17	
S5.1-SD-MS-1030	Foundations Start Date - Segment 5.1	16-Nov-17	
S5.1-SD-MS-1040	Structure Installation Start Date - Segment 5.1	07-Dec-17	
S5.1-SD-MS-1050	Conductor Installation Start Date - Segment 5.1	30-Jan-18	
S5.1-SD-MS-1060	OHGW Installation Start Date - Segment 5.1	30-Jan-18	
S5.1-SD-MS-1070	OPGW Installation Start Date - Segment 5.1	21-Feb-18	
Order Dates		04-Aug-16	16-Nov-16
S5.1-OD-MS-1010	Structure Mill Order Date - Segment 5.1	04-Aug-16	
S5.1-OD-MS-1020	Anchor Bolts Order Date - Segment 5.1	16-Nov-16	
S5.1-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment ...	16-Nov-16	
S5.1-OD-MS-1040	Conductor Order Date - Segment 5.1	16-Nov-16	
S5.1-OD-MS-1050	OPGW Order Date - Segment 5.1	16-Nov-16	
S5.1-OD-MS-1060	Structure Release Date - Segment 5.1	16-Nov-16	

🟩 Remaining Level of Effort
▬ % Complete
🟦 Actual Level of Effort
▼ Summary
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ ◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Development, Milestone.

Layout: MAT Construction Milestone Layout_1

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

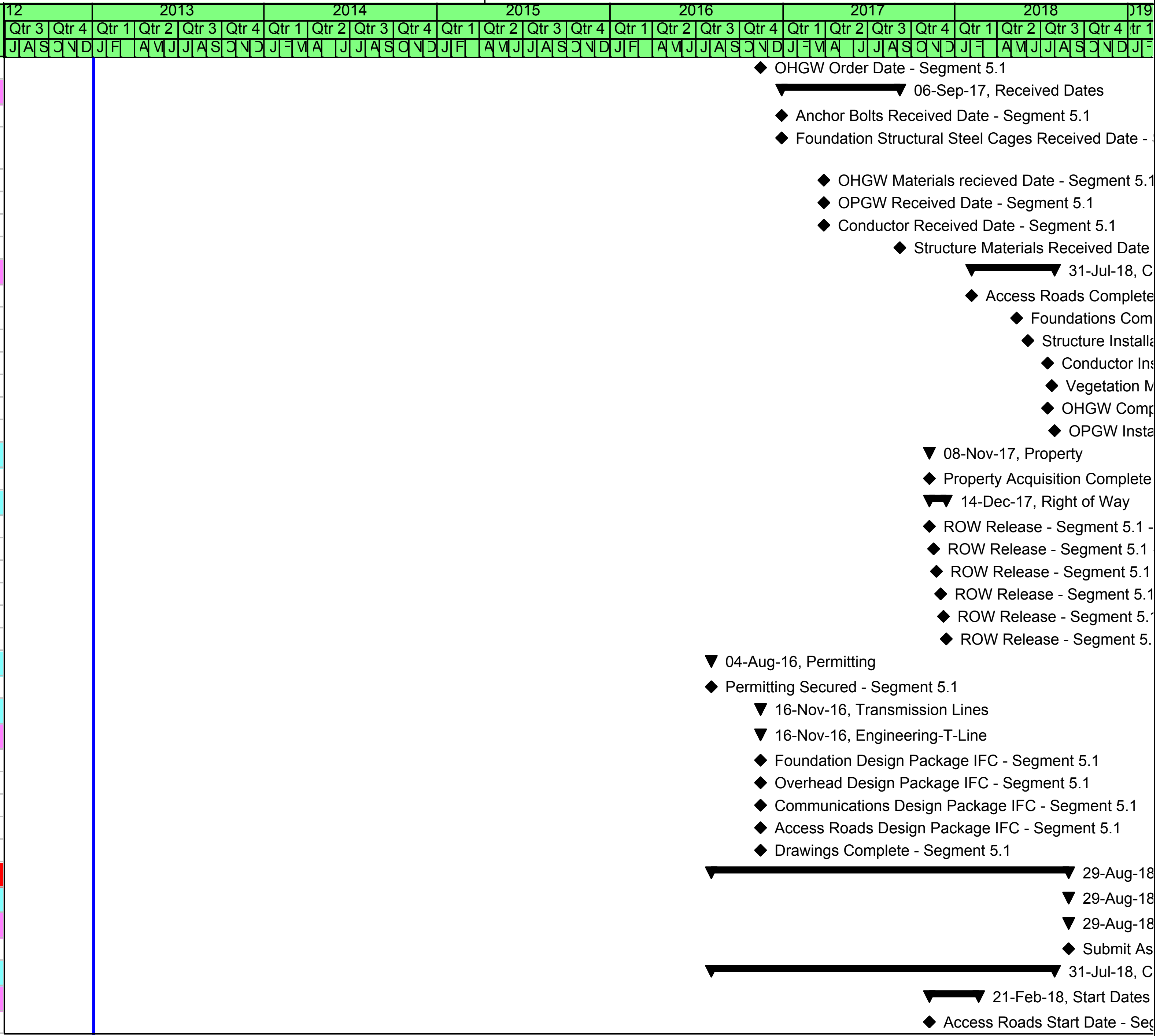
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S5.1-OD-MS-1070	OHGW Order Date - Segment 5.1	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S5.1-RD-MS-1010	Anchor Bolts Received Date - Segment 5.1		30-Dec-16
S5.1-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segment 5.1		30-Dec-16
S5.1-RD-MS-1030	OHGW Materials recieved Date - Segment 5.1		28-Mar-17
S5.1-RD-MS-1040	OPGW Received Date - Segment 5.1		28-Mar-17
S5.1-RD-MS-1050	Conductor Received Date - Segment 5.1		28-Mar-17
S5.1-RD-MS-1060	Structure Materials Received Date - Segment 5.1		06-Sep-17
Completion Dates		06-Feb-18	31-Jul-18
S5.1-CD-MS-1010	Access Roads Complete - Segment 5.1		06-Feb-18
S5.1-CD-MS-1020	Foundations Complete - Segment 5.1		11-May-18
S5.1-CD-MS-1030	Structure Installation Complete - Segment 5.1		04-Jun-18
S5.1-CD-MS-1040	Conductor Installation Complete - Segment 5.1		17-Jul-18
S5.1-CD-MS-1050	Vegetation Management Complete - Segment 5.1		24-Jul-18
S5.1-CD-MS-1060	OHGW Complete - Segment 5.1		17-Jul-18
S5.1-CD-MS-1070	OPGW Installation Complete - Segment 5.1		31-Jul-18
Property		08-Nov-17	08-Nov-17
S5.1-PRP-1000	Property Acquisition Complete - Segment 5.1		08-Nov-17
Right of Way		08-Nov-17	14-Dec-17
S5.1-ROW-1000	ROW Release - Segment 5.1 - A	08-Nov-17	
S5.1-ROW-1010	ROW Release - Segment 5.1 - B	16-Nov-17	
S5.1-ROW-1020	ROW Release - Segment 5.1 - C	23-Nov-17	
S5.1-ROW-1030	ROW Release - Segment 5.1 - D	30-Nov-17	
S5.1-ROW-1040	ROW Release - Segment 5.1 - E	07-Dec-17	
S5.1-ROW-1050	ROW Release - Segment 5.1 - F	14-Dec-17	
Permitting		04-Aug-16	04-Aug-16
S5.1-PMT-1000	Permitting Secured - Segment 5.1		04-Aug-16
Transmission Lines		15-Nov-16	16-Nov-16
Engineering-T-Line		15-Nov-16	16-Nov-16
S5.1-ENG-1120	Foundation Design Package IFC - Segment 5.1		15-Nov-16
S5.1-ENG-1130	Overhead Design Package IFC - Segment 5.1		15-Nov-16
S5.1-ENG-1140	Communications Design Package IFC - Segment 5.1		15-Nov-16
S5.1-ENG-1150	Access Roads Design Package IFC - Segment 5.1		15-Nov-16
S5.1-ENG-1160	Drawings Complete - Segment 5.1		16-Nov-16
Segment 5.2 (58 kilometers)		04-Aug-16	29-Aug-18
Project Management		29-Aug-18	29-Aug-18
Project Support		29-Aug-18	29-Aug-18
S5.2-ENG-9020	Submit As-Builts - Segment 5.2		29-Aug-18
Contractor Milestones Segment 5.2		04-Aug-16	31-Jul-18
Start Dates		08-Nov-17	21-Feb-18
S5.2-SD-MS-1010	Access Roads Start Date - Segment 5.2	08-Nov-17	



🟩	Remaining Level of Effort	▬	% Complete
▬	Actual Level of Effort	▼▬▼	Summary
🟦	Actual Work		
🟩	Remaining Work		
🟥	Critical Remaining Work		
◆ ◆	Milestone		

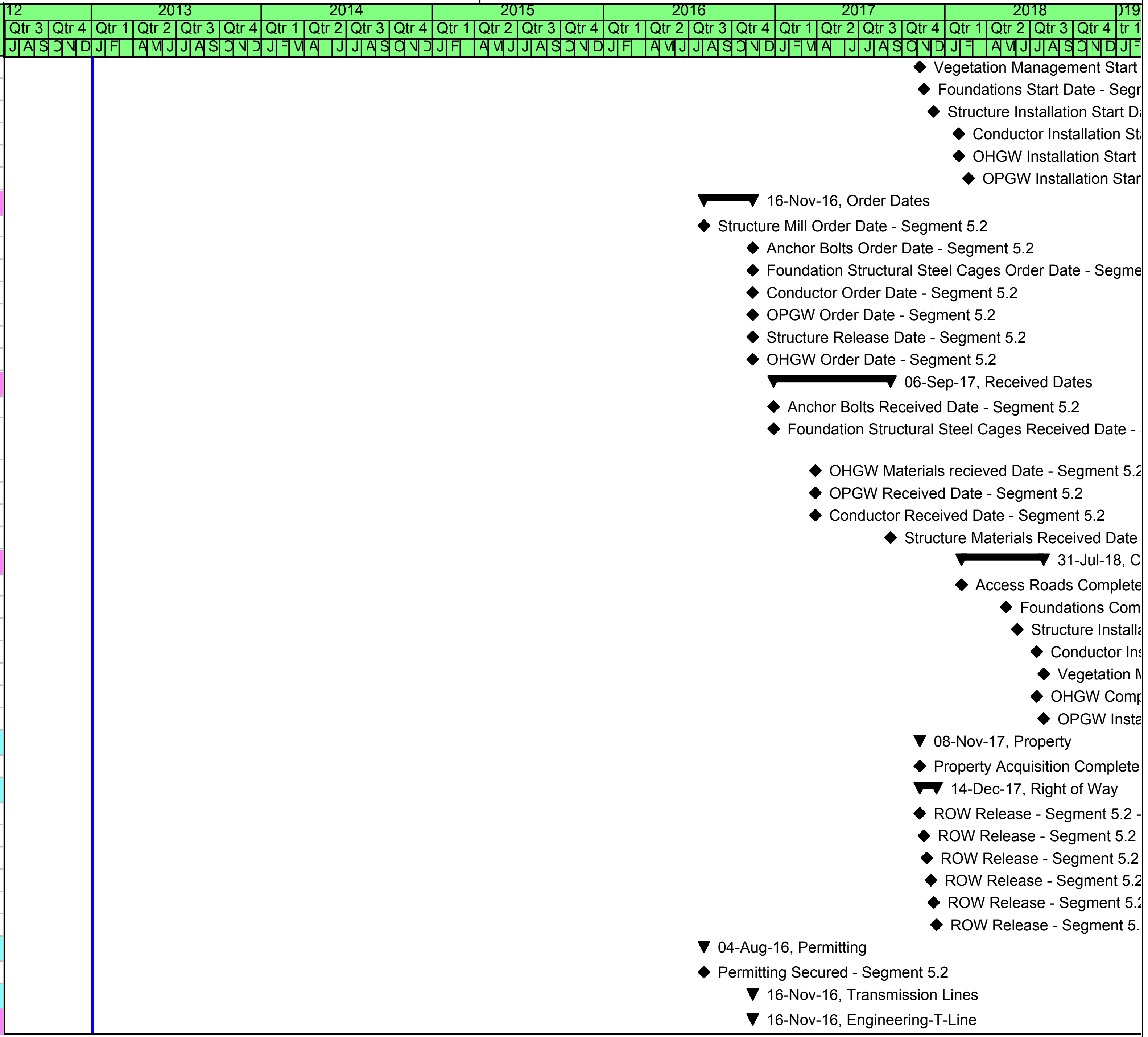
Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Development, Milestone.

Layout: MAT Construction Milestone Layout_1

Activity ID	Activity Name	Start	Finish
S5.2-SD-MS-1020	Vegetation Management Start Date - Segment 5.2	08-Nov-17	
S5.2-SD-MS-1030	Foundations Start Date - Segment 5.2	16-Nov-17	
S5.2-SD-MS-1040	Structure Installation Start Date - Segment 5.2	07-Dec-17	
S5.2-SD-MS-1050	Conductor Installation Start Date - Segment 5.2	30-Jan-18	
S5.2-SD-MS-1060	OHGW Installation Start Date - Segment 5.2	30-Jan-18	
S5.2-SD-MS-1070	OPGW Installation Start Date - Segment 5.2	21-Feb-18	
Order Dates		04-Aug-16	16-Nov-16
S5.2-OD-MS-1010	Structure Mill Order Date - Segment 5.2	04-Aug-16	
S5.2-OD-MS-1020	Anchor Bolts Order Date - Segment 5.2	16-Nov-16	
S5.2-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment ...	16-Nov-16	
S5.2-OD-MS-1040	Conductor Order Date - Segment 5.2	16-Nov-16	
S5.2-OD-MS-1050	OPGW Order Date - Segment 5.2	16-Nov-16	
S5.2-OD-MS-1060	Structure Release Date - Segment 5.2	16-Nov-16	
S5.2-OD-MS-1070	OHGW Order Date - Segment 5.2	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S5.2-RD-MS-1010	Anchor Bolts Received Date - Segment 5.2		30-Dec-16
S5.2-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segment 5.2		30-Dec-16
S5.2-RD-MS-1030	OHGW Materials recieved Date - Segment 5.2		28-Mar-17
S5.2-RD-MS-1040	OPGW Received Date - Segment 5.2		28-Mar-17
S5.2-RD-MS-1050	Conductor Received Date - Segment 5.2		28-Mar-17
S5.2-RD-MS-1060	Structure Materials Received Date - Segment 5.2		06-Sep-17
Completion Dates		06-Feb-18	31-Jul-18
S5.2-CD-MS-1010	Access Roads Complete - Segment 5.2		06-Feb-18
S5.2-CD-MS-1020	Foundations Complete - Segment 5.2		11-May-18
S5.2-CD-MS-1030	Structure Installation Complete - Segment 5.2		04-Jun-18
S5.2-CD-MS-1040	Conductor Installation Complete - Segment 5.2		17-Jul-18
S5.2-CD-MS-1050	Vegetation Management Complete - Segment 5.2		31-Jul-18
S5.2-CD-MS-1060	OHGW Complete - Segment 5.2		17-Jul-18
S5.2-CD-MS-1070	OPGW Installation Complete - Segment 5.2		31-Jul-18
Property		08-Nov-17	08-Nov-17
S5.2-PRP-1000	Property Acquisition Complete - Segment 5.2		08-Nov-17
Right of Way		08-Nov-17	14-Dec-17
S5.2-ROW-1000	ROW Release - Segment 5.2 - A	08-Nov-17	
S5.2-ROW-1010	ROW Release - Segment 5.2 - B	16-Nov-17	
S5.2-ROW-1020	ROW Release - Segment 5.2 - C	23-Nov-17	
S5.2-ROW-1030	ROW Release - Segment 5.2 - D	30-Nov-17	
S5.2-ROW-1040	ROW Release - Segment 5.2 - E	07-Dec-17	
S5.2-ROW-1050	ROW Release - Segment 5.2 - F	14-Dec-17	
Permitting		04-Aug-16	04-Aug-16
S5.2-PMT-1000	Permitting Secured - Segment 5.2		04-Aug-16
Transmission Lines		15-Nov-16	16-Nov-16
Engineering-T-Line		15-Nov-16	16-Nov-16



🟩 Remaining Level of Effort
▬ % Complete
🟦 Actual Level of Effort
▼ Summary
🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work
◆ Milestone

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Development, Milestone.

Layout: MAT Construction Milestone Layout_1

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

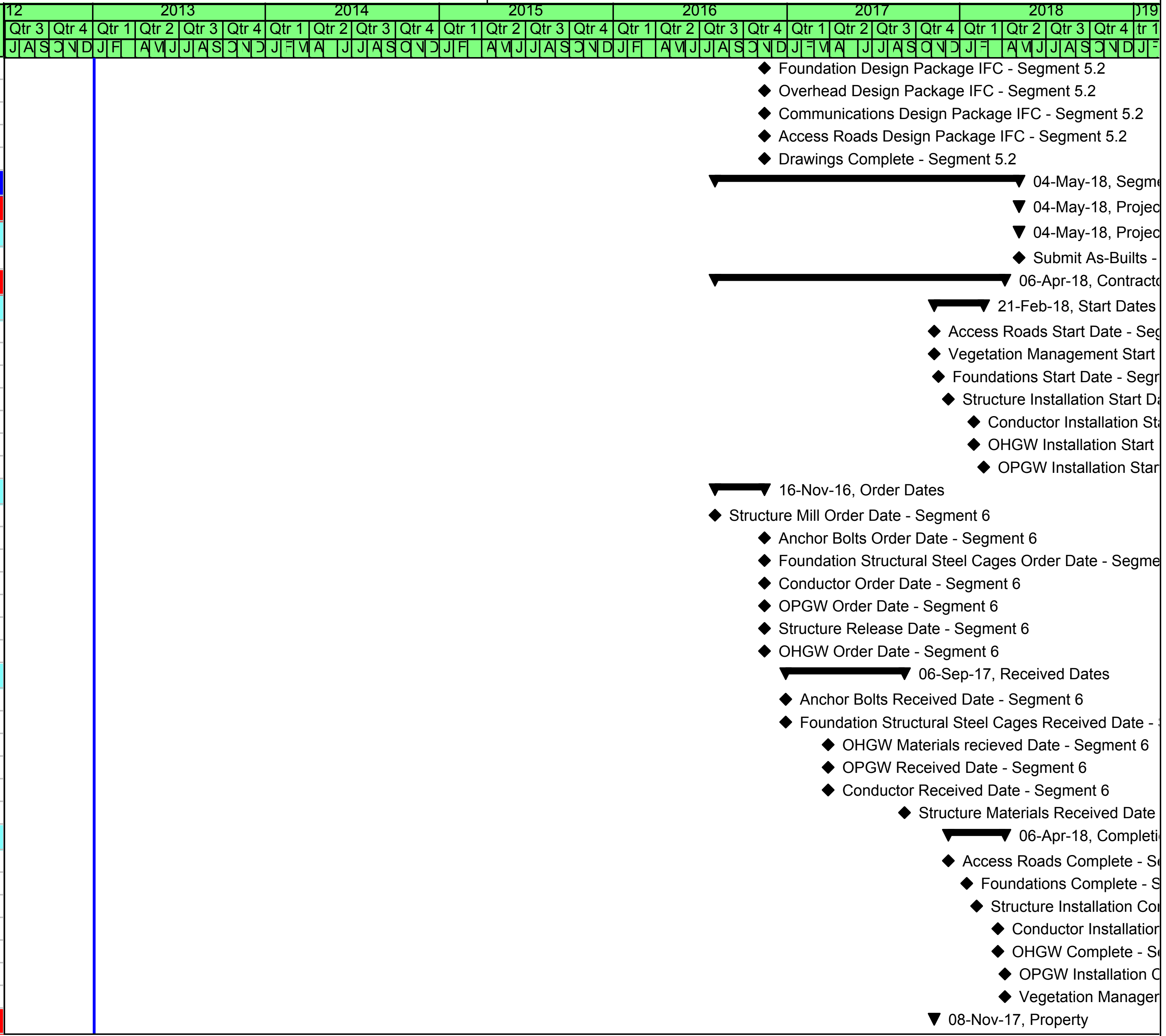
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S5.2-ENG-1120	Foundation Design Package IFC - Segment 5.2		15-Nov-16
S5.2-ENG-1130	Overhead Design Package IFC - Segment 5.2		15-Nov-16
S5.2-ENG-1140	Communications Design Package IFC - Segment 5.2		15-Nov-16
S5.2-ENG-1150	Access Roads Design Package IFC - Segment 5.2		15-Nov-16
S5.2-ENG-1160	Drawings Complete - Segment 5.2		16-Nov-16
Segment 6 Wawa - Substation (20 km)		04-Aug-16	04-May-18
Project Management		04-May-18	04-May-18
Project Support		04-May-18	04-May-18
S6-ENG-9020	Submit As-Builts - Segment 6		04-May-18
Contractor Milestones Segment 6		04-Aug-16	06-Apr-18
Start Dates		08-Nov-17	21-Feb-18
S6-SD-MS-1010	Access Roads Start Date - Segment 6	08-Nov-17	
S6-SD-MS-1020	Vegetation Management Start Date - Segment 6	08-Nov-17	
S6-SD-MS-1030	Foundations Start Date - Segment 6	16-Nov-17	
S6-SD-MS-1040	Structure Installation Start Date - Segment 6	07-Dec-17	
S6-SD-MS-1050	Conductor Installation Start Date - Segment 6	30-Jan-18	
S6-SD-MS-1060	OHGW Installation Start Date - Segment 6	30-Jan-18	
S6-SD-MS-1070	OPGW Installation Start Date - Segment 6	21-Feb-18	
Order Dates		04-Aug-16	16-Nov-16
S6-OD-MS-1010	Structure Mill Order Date - Segment 6	04-Aug-16	
S6-OD-MS-1020	Anchor Bolts Order Date - Segment 6	16-Nov-16	
S6-OD-MS-1030	Foundation Structural Steel Cages Order Date - Segment 6	16-Nov-16	
S6-OD-MS-1040	Conductor Order Date - Segment 6	16-Nov-16	
S6-OD-MS-1050	OPGW Order Date - Segment 6	16-Nov-16	
S6-OD-MS-1060	Structure Release Date - Segment 6	16-Nov-16	
S6-OD-MS-1070	OHGW Order Date - Segment 6	16-Nov-16	
Received Dates		30-Dec-16	06-Sep-17
S6-RD-MS-1010	Anchor Bolts Received Date - Segment 6		30-Dec-16
S6-RD-MS-1020	Foundation Structural Steel Cages Received Date - Segm...		30-Dec-16
S6-RD-MS-1030	OHGW Materials recieved Date - Segment 6		28-Mar-17
S6-RD-MS-1040	OPGW Received Date - Segment 6		28-Mar-17
S6-RD-MS-1050	Conductor Received Date - Segment 6		28-Mar-17
S6-RD-MS-1060	Structure Materials Received Date - Segment 6		06-Sep-17
Completion Dates		07-Dec-17	06-Apr-18
S6-CD-MS-1010	Access Roads Complete - Segment 6		07-Dec-17
S6-CD-MS-1020	Foundations Complete - Segment 6		16-Jan-18
S6-CD-MS-1030	Structure Installation Complete - Segment 6		06-Feb-18
S6-CD-MS-1040	Conductor Installation Complete - Segment 6		21-Mar-18
S6-CD-MS-1050	OHGW Complete - Segment 6		21-Mar-18
S6-CD-MS-1060	OPGW Installation Complete - Segment 6		06-Apr-18
S6-CD-MS-1070	Vegetation Management Complete - Segment 6		06-Apr-18
Property		08-Nov-17	08-Nov-17



- 🟩 Remaining Level of Effort
- 🟦 Actual Level of Effort
- 🟦 Actual Work
- 🟩 Remaining Work
- 🟥 Critical Remaining Work
- ◆ Milestone
- ▬ % Complete
- ▼ Summary

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Development, Milestone.

Layout: MAT Construction Milestone Layout_1

MIDAMERICAN TRANSMISSION

Project ID: MAT-12-05-12-C

Project Name: E-W Tie - 12-05-12 OEB Post Bid

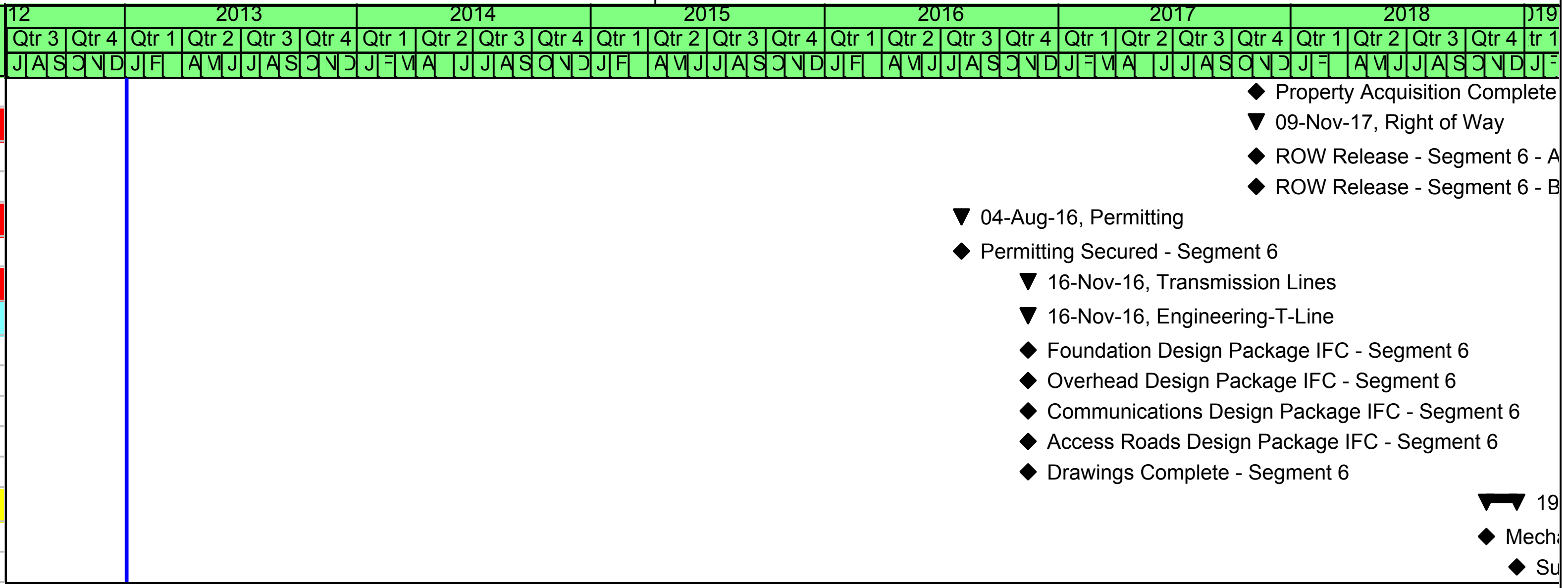
In-Service Date: 19 Dec 2018

Project Manager: Smith, Brandon

PCS: Johnson, Mike

Print Date: 13-Dec-12

Activity ID	Activity Name	Start	Finish
S6-PRP-1000	Property Acquisition Complete - Segment 6		08-Nov-17
Right of Way		08-Nov-17	09-Nov-17
S6-ROW-1000	ROW Release - Segment 6 - A	08-Nov-17	
S6-ROW-1010	ROW Release - Segment 6 - B	09-Nov-17	
Permitting		04-Aug-16	04-Aug-16
S6-PMT-1000	Permitting Secured - Segment 6		04-Aug-16
Transmission Lines		15-Nov-16	16-Nov-16
Engineering-T-Line		15-Nov-16	16-Nov-16
S6-ENG-1120	Foundation Design Package IFC - Segment 6		15-Nov-16
S6-ENG-1130	Overhead Design Package IFC - Segment 6		15-Nov-16
S6-ENG-1140	Communications Design Package IFC - Segment 6		15-Nov-16
S6-ENG-1150	Access Roads Design Package IFC - Segment 6		15-Nov-16
S6-ENG-1160	Drawings Complete - Segment 6		16-Nov-16
Completion Dates		02-Nov-18	19-Dec-18
MC-1000	Mechanical Completion		02-Nov-18
SC-1000	Substantial Completion		19-Dec-18



▬ Remaining Level of Effort

▬ Actual Level of Effort

🟦 Actual Work

🟩 Remaining Work

🟥 Critical Remaining Work

◆ ◆ Milestone

▬ % Complete

▼▬▼ Summary

Data Date: 04-Jan-13

Baseline:

TASK filters: Hide Development, Milestone.

Layout: MAT Construction Milestone Layout_1

TAB N-3-3

Construction Phase – Schedule Risks and Mitigation Strategy

Table N-2, below, summarizes major Construction Phase schedule risks, the associated mitigation strategy, the likelihood of occurrence and assessed level of impact.

Table N-2

Schedule Exposure					
Category	**Issue/Description**	**Item**	**Mitigation Strategy**	**Likelihood**	**Severity**
Construction	Unavailability of local labour, requiring additional non-Ontario based resources. Associated tax, inducement and travel cost risks.	1	Develop contractor relationships based on development team experience. Local promotion program to garner interest from local contractors. First Nation and Métis participation for local resources.	Somewhat Likely	Minor
Construction	Unanticipated availability and cost of materials and supplies	2	Competitive bids from Canadian suppliers; use of man-camps and FN contractors. Use of an experienced and well resourced EPC Contractor	Somewhat Likely	Minor
Construction	Accuracy of baseline assumptions for route, total line length, general scope inclusions and project plan	3	On the ground field inspections and line route assessments. Ability to site a new line corridor around National Parks and First Nations lands. Coordinate route selection, live engineering studies and survey work to provide most efficient solutions.	Likely	Major

Schedule Exposure					
Category	**Issue/Description**	**Item**	**Mitigation Strategy**	**Likelihood**	**Severity**
Construction	Prolonged and/or unanticipated inclement weather	4	Flexible tasks and schedules to optimize weather conditions. Use of experienced and well resourced EPC contractor.	Somewhat Likely	Moderate
Legal	Unanticipated litigation and additional costs to secure land rights needed for access, construction, and operations	5	Use of experienced Ontario counsel and MNR policy where applicable	Somewhat Likely	Moderate
Land Rights Acquisition Costs	Unanticipated costs and obligations required to accommodate parties with land rights needed to for access, construction, and operations	6	Use of expropriation rights and early access rights, if necessary	Likely	Moderate
Acquisition of Mining & Timber Rights	Unanticipated additional payments required to accommodate parties with mining and timber rights on Crown lands	7	Fair valuations and active negotiations, supported by land experts and legal counsel, with some portion of payments triggered by mining activities	Likely	Major
Environmental Assessment	Delays in MNR approval of the EA that extend beyond the date of the LTC decision	8	Use of experienced Ontario consultants (Stantec or comparable equivalent) to prepare and submit a complete EA	Somewhat Likely	Major

Schedule Exposure					
Category	**Issue/Description**	**Item**	**Mitigation Strategy**	**Likelihood**	**Severity**
Administrative/ Regulatory	Untimely decisions and/or actions by regulatory agencies or Hydro One, including delays in completing substation work.	9	Early and proactive outreach supported by consultants as required; timely and complete applications	Not Likely	Moderate
Design/Engineering	Route modifications that increase the total length to more than 410 km	10	Participation in the final route selection process to identify the most cost-effective and socially acceptable route refinements	Not Likely	Minor
Construction	Unanticipated road improvements and helicopter usage - Unknown grade and shallow subgrade conditions - Detailed topographic assessment not yet done; actual cut/fill, alignment adjustments/reroutes due to extreme grades, or 3D evaluation not done - Actual transport plan (final) not developed or optimized - Assumed we can use existing ROW, if not and new access roads are required along the entire new ROW, this is not accounted for in quantities - Access roads increased as number of structures	11	Detailed road access assessment performed as part of the bid preparation process by locally experienced contractors. Coordination with Hydro One and landowners for optimized access across property. Use of well resourced EPC contractor.	Somewhat Likely	Minor

Schedule Exposure					
Category	**Issue/Description**	**Item**	**Mitigation Strategy**	**Likelihood**	**Severity**
	not final (no final design/layout) - Unknown restrictions to access (if any) that would preclude certain access routes, etc				
Design/Engineering	Unanticipated changes in select structure & tower requirements - H-frame structure weights estimated using design software with estimated loading. Due to height additional weight due to multiple shaft flange joints was estimated. Weights from a H-frame 345 project were also utilized. - H-frame structure quantities are estimates based on average span length and not terrain spotting. Terrain restrictions could increase quantities or decrease. - Clearances to water bodies range from 12.5m to 18.5m. There are many crossings at midspan which could increase height. - Snow clearance; line clearance height	12	Owners Engineer to be engaged early in development phase to work with Environmental, ROW and project development team to optimize the design for the most efficient structure locations. OE to refine tower specifications. Use of an experienced and well resourced EPC contractor.	Not Likely	Minor

Schedule Exposure					
Category	**Issue/Description**	**Item**	**Mitigation Strategy**	**Likelihood**	**Severity**
	after snow fall - Tower reactions may vary some as exact tower heights and spans were not used. Average spans utilized have some variations. - Galloping requirements could increase the phase spacing (middle arm of the tower and increase weight. - Hotline work is required for the structure configuration. This was roughly incorporated but not verified for phase spacing and clearance to structure face. - Single circuit lattice deadend tower weights were estimated from BPA tower which has an extreme ice condition of 3 inches. Weights were reduced based on engineering judgment.				
Design/Engineering	Unanticipated design for Extreme Winds	13	Review with OE. Utilize latest wind data during mutual design phase.	Not Likely	Minor
Design/Engineering	Unanticipated foundation requirements - Final ratio of	14	Geotechnical investigations, site-inspections, and timely reaction to local unexpected	Somewhat Likely	Minor

Schedule Exposure					
Category	**Issue/Description**	**Item**	**Mitigation Strategy**	**Likelihood**	**Severity**
	foundation types unknown (no final breakdown of subgrade conditions) - Potential increase in quantity of rock areas - No geotech data available, assumed foundation design/mix - Unknown final layout/number of structures known impacting foundation design/scope - Snow creep; differential melting impacts loads on structures		conditions. Use of an experienced and well resourced EPC contractor.		
Environmental Compliance	Unanticipated additional environmental mitigation	15	Close coordination with MNR and MOE throughout TOR and EA process.	Somewhat Likely	Major
Design/Engineering	Unanticipated grounding requirements, difficulty in achieving resistance requirements	16	Engage grounding experts and specialist vendors.	Very Likely	Minor
Construction	Unanticipated site clearance requirements and costs	17	Use of an experienced and well resourced EPC contractor and First Nation and Métis contracting including performance incentives; coordination with Hydro One	Not Likely	Minor
Design/Engineering	Localized need to expand 50 m corridor width	18	Review design and tower locations to minimize blowout impacts. Work with	Not Likely	Minor

Schedule Exposure

Category	**Issue/Description**	**Item**	**Mitigation Strategy**	**Likelihood**	**Severity**
			landowners and Hydro One to negotiate easement mitigations		
Design/Engineering	Unanticipated additional transmission line crossings of existing East-West Transmission line	19	Participation in the final route selection process to identify the most cost-effective and socially acceptable route refinements	Not Likely	Minor
Permits	Unanticipated problems in securing permits by no later than six months after the completion of LTC hearings	20	Early and proactive efforts to secure permits during and within six months of the end of LTC hearings	Somewhat Likely	Moderate
Design/Engineering	Transposition Structures	21	Owners Engineer to define final requirements	Very Likely	Minor
Legal	Unanticipated additional support required in OEB Designation & LTC proceedings	22	Use of experienced Ontario counsel and external service provides as needed.	Not Likely	Minor

TAB N-4-1

Reporting Requirements

Proposed Reporting Requirements

The Applicant proposes four levels of reporting during the Project's Development and Construction Phases.

(i) By contract, all consultants and contractors will be required to submit a comprehensive, monthly report describing progress made, expenditures incurred, costs that are forecast, milestones achieved and the scope of work planned for the next period. Each consultant and contractor will also be required to submit a detailed schedule, in Primavera format, at the outset, identifying all deliverables and the critical path. Each monthly report will chart the month's progress against the schedule and indicate any variances from the critical path. The schedule must be consistent with the Project work breakdown structure in order all consultants' and contractors' schedules can be analyzed for inter-relationships, consistency and areas of mutual concern and risk. During the Construction Phase, key component installation quantities will be tracked, including items such as access roads, foundations, towers and conductor installations.

(ii) The project manager will be required to submit, to the Applicant's management team, weekly progress reports based on project meetings and activities. The reports will highlight progress, action items, areas of concern and proposed strategies for addressing these. These reports will provide the management team with a clear view of the Project, requests for advice (as applicable) and a record of Project decisions. During the weekly management call, the project manager will review these reports to help the management team monitor progress.

(iii) Monthly progress reports will be submitted to the Applicant's management team and Board of Directors in order to keep senior executives current on key deliverables and indicators and the status of risk items.

(iv) The Applicant proposes that monthly and quarterly progress reports also be filed with the OEB during both the Development Phase and the Construction Phase. Construction Phase reports could be similar to those that Hydro One was required to file in connection with Bruce-Milton Project[1].

Failure to Meet Reporting Obligations

Both the RES Group and the MidAmerican Group have implemented successful reporting structures on other transmission infrastructure projects. The Applicant's management team has a great deal of experience in delivering accurate and timely status reports to regulators in jurisdictions across North America. It will require Project contractors to provide their own status reports each month along with their invoice application. If a contractor fails to provide a report, the invoice application will be treated as incomplete and payment will be deferred until the report is provided. This approach has proven to be an effective tool in ensuring timely reporting.

---

[1] EB-2007-0050 Decision and Order (September 15, 2008), Appendix C – Conditions of Approval.

TAB N-5-1

Innovative Practices to Accelerate Project Schedule

Transmission Engineering and Construction

The Preferred Design uses a single circuit TSP H-frame tower structure with a single 1557 ACSS/TW conductor. The conductor will be supported by a single insulator string comprised of toughen glass to reduce construction damage and improve long term performance. As an alternative, polymer insulators will also be considered for their ease of installation, resistance to pollution for better reliability and lower construction costs. Polymer insulators are also less prone to vandalism from gunshots.

The purpose for using TSP H-frame as the primary structure is that for a single circuit 230 kV system, this is the most efficient structural element. TSPs are largely shop-fabricated and field-erected with simple bolted flange joints which eliminates the need for preassembly at material yards. This structure system will also adapt to a variety of foundations systems that are used for lattice towers but also has the advantage of direct embedment. The segmentation of these structures easily facilitates flying in structure portions by helicopter to areas where access is difficult. TSPs can be fabricated using either dulled galvanized steel or self-weathering steel based on visual impact.

Efficient wire stringing will typically employ the use of helicopters to install the pulling line. Helicopters will also be used as deemed appropriate and efficient to fly in workers, tools, supplies and, even, towers as needed.

Splicing and deadending of conductor will use either typical hydraulic compression or implosive materials.

Geotechnical Engineering and Geologic Hazards Assessment

To minimize delays associated with obtaining geotechnical and geologic information needed to design this project, the Applicant will utilize an innovative approach that incorporates a comprehensive planning effort based upon available desktop information. This will include any available information from the existing East-West Tie line, as well as any publicly available information. These efforts will take place prior to obtaining rights of entry.

Consultants with local expertise will be utilized to complete the desktop geotechnical and geological studies. These studies will assist in planning and focusing the targeted field testing and data collection program. Geotechnical borings will be sited, access for drill rigs will be planned and drill rigs types specified. Borings will initially be planned at every dead-end and angle point, as well as every three miles on tangent sections. Additional borings will be planned where indicated by the desktop assessment. Onsite test results will be augmented by samples testing in accordance with a comprehensive laboratory testing program.

Site visits will be planned for the purpose of geologic hazard verification and geophysical testing. Upon obtaining rights of entry, drill rigs, geotechnical engineers and engineering geologists will be mobilized to gather field data in order to inform the foundation and access road designs. A final geotechnical and geologic hazards report will be prepared, based on the field data gathering program. The report will detail soil and rock strength parameters for use in foundation design as well as provide recommendations for mitigation of identified geotechnical issues and geologic hazards. Recommendations will be provided for access road and pad construction, foundation type and design parameters applicable to the conditions encountered, construction techniques, and inspection requirements.

Foundation Design

It is anticipated that equipment access, material availability, soft soils/muskeg and rock will be the primary challenges related to foundations for this project. The Applicant will approach these challenges by integrating constructability in the design process. The most appropriate foundation will be selected and designed for the loading demands and conditions that are expected to be encountered at the structure location.

Drilled shaft concrete piers will be utilized whenever possible. Alternate foundations will be designed where appropriate. Planned alternate foundations include grillage, rock anchor, pad and pedestal, and direct embed. Rock anchors for lattice towers will be specified where appropriate. Grillages or concrete pad and pedestals will be used where soil conditions permit. H-Frame tangents may be directly embedded in intermediate geomaterials. For H-Frames in rock, a grouted anchor system with a concrete cap that incorporates anchor-bolts is being developed. A grillage type foundation is proposed for soft soil or muskeg conditions. We expect this foundation to be rarely used based upon limitations associated with embedment. Helical piers will be utilized in soil, soft soil, and muskeg conditions if needed to support access and schedule restrictions.

Construction Innovations

Construction will take place in wet areas during winter to take advantage of frozen soil conditions and minimize ground disturbance. Wooden mats will be utilized to spread loads from construction equipment in soft or wet soils where construction cannot be completed in frozen conditions. Where steep terrain or concrete availability prohibits transportation of concrete delivery trucks or large foundation drill rigs, foundations will be utilize that limit the amount of concrete delivered and excavation required. H-Frames will utilize flanged base plates in order to maximize flexibility for connection to specified foundations. Williams anchors are planned for rock/soil, where applicable. Excavations for the anchors will be advanced using a small footprint drill rig. If necessary, crews, the drill equipment and construction materials could be delivered by helicopter.

TAB O-1-1

Overview

As will be explained in detail in Exhibit P, the EWTL, if developed and constructed in accordance with the Applicant's Preferred Design over the Preliminary Preferred Route, will require total capital expenditures of $413.4 million (not including escalation for inflation or any CWIP component) for development and construction and, at least $2.2 million annually, for O&M. These figures are subject to the assumptions and qualifications discussed in Exhibit P. Using a capital structure of 60 percent debt and 40 percent equity, the Project will accordingly require an equity contribution totaling $165.4 million and debt of $248 million.

MidAmerican Group

It is understood that long-term investments can require long-term development horizons. The MidAmerican Group is structured to develop and own transmission assets for the life of the asset and its financing strategies reflect this same approach, to manage and mitigate risk and cost over the short to long term. The MidAmerican Group owns electric and gas assets totalling $47.7 billion, as of December 31, 2011, has undertaken $2.6 billion in capital expenditures in 2011, and supports $2.5 billion in ongoing operating expenditures. The MidAmerican Group has ample access to debt and equity capital in support of its project development activities. Since 2004, the MidAmerican Group has invested or committed to invest $6 billion in owned and operated wind power generation.

The RES Group

The RES Group has considerable experience developing, financing, and constructing electricity infrastructure projects. The RES Group has directly financed in excess of 600 MW of renewable electricity generation projects (spanning more than 30 different wind/solar facilities) representing over $1 billion in total investment. The RES Group has been involved in over six GW of renewable energy transactions and has been at the forefront of financing projects globally for the last 20 years. This provides the RES Group with unrivalled experience and expertise in financing projects. The RES Group has the in-house skills and close links with banks, finance houses, investors, insurers, manufacturers, consultants and legal specialists necessary to allow it to assemble the best financing arrangements for a particular project. When combined with its technical, engineering and environmental expertise, the RES Group consistently adds extra value to all its projects.

Financial Plan

Application Phase – Initiation of Designation Process to Submission of Application for Designation

The Applicant has financed its bid development costs from sponsor equity. To reduce the rate impact to ratepayers, the Applicant does not intend to seek recovery of the costs incurred in this phase of the Project. These costs are estimated to be up to $1.5 million.

Development Phase – Designation to Filing for Leave to Construct for the EWTL

During the Development Phase, the Applicant intends to finance its expenses, 100 percent from sponsor equity, understanding it is not practical to obtain debt financing at that time, as the Project will not be generating revenue in this period; to attempt to obtain financing at competitive rates would not be possible.

Construction Phase – From Filing of Leave to Construct for the EWTL to Commercial Operation

During the Construction Phase, the Applicant intends to finance its construction expenses with a construction debt facility and sponsor equity contributions pursuant to a 60%:40% ratio. The Applicant is confident that through the relationships and experience of the RES Group and the MidAmerican Group, it will obtain such debt at competitive rates.

Operations Phase – Following Commercial Operation

Following commercial operation of the EWTL, the Applicant intends to obtain long-term debt financing for 60 percent of the total Project costs and the remaining 40 percent will be met by sponsor equity contributions. It is anticipated, although difficult to predict so far out, that long-term debt fixed interest rates of 4.5 percent to 5.0 percent are likely to be available to the Applicant at such time. This will be based on a 10 year term and this long-term debt will be refinanced twice at 10 year intervals so that there is full pay-off in 30 years.

The Applicant intends to maintain equity of 40 percent in the operations phase to meet the Board's regulatory requirements and also to be able to raise required long-term and short-term debt at competitive rates. If needed, the Applicant may seek to obtain a credit rating after its first rate application is approved.

The Applicant may consider supplementing its long-term debt facility with a short-term revolving facility having a three year renewable term at fixed interest rates. Typically, a commitment fee is also charged on such facilities on the unused portion of the total credit available. Each three years, the facility would be reviewed with debt limits negotiated based on the following three year's forecasted needs for the operation of the EWTL, which would keep commitment and issuance fees to a minimum.

The Board has requested the Applicant to confirm that financing of the EWTL will not have a significant adverse effect on the Applicant's creditworthiness or financial condition and what effect the EWTL will have to the Applicant's cost of debt. The Applicant is a special purpose vehicle so it is more appropriate to address this in the context of the RES Group and the MidAmerican Group. Exhibit O-1-2 contains financial statements for the RES Group and Exhibit O-1-3 contains financial statements for the MidAmerican Group that indicate a significantly high level of capital and reserves to make this not an issue. Also, due to the regulated nature of the EWTL and its relative small value when compared to the total financial capacity of the RES Group and the

MidAmerican Group, the Project will not result in a material impact on the Applicant's cost of debt. Similarly, cost overruns or delays do not create material concerns in the context of the financial capacity of the RES Group and the MidAmerican Group and their ability to access debt markets.

TAB O-1-2

RES Group - Financial Statements

Confidentially Filed.

TAB O-1-3

MidAmerican Group – Financial Statements

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[X] Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 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	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
001-14881	**MIDAMERICAN ENERGY HOLDINGS COMPANY** **(An Iowa Corporation)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**94-2213782**

N/A

(Former name, former address and former fiscal year, if changed since last report)

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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ 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 ☒

All of the shares of common equity of MidAmerican Energy Holdings Company are privately held by a limited group of investors. As of October 31, 2012, 74,609,001 shares of common stock were outstanding.

TABLE OF CONTENTS

PART I

PART II

Definition of Abbreviations and Industry Terms

When used in Part I, Items 2 through 4, and Part II, Items 1 through 6, the following terms have the definitions indicated.

MidAmerican Energy Holdings Company and Related Entities	
MEHC	MidAmerican Energy Holdings Company
Company	MidAmerican Energy Holdings Company and its subsidiaries
PacifiCorp	PacifiCorp and its subsidiaries
MidAmerican Funding	MidAmerican Funding, LLC
MidAmerican Energy	MidAmerican Energy Company
Northern Natural Gas	Northern Natural Gas Company
Kern River	Kern River Gas Transmission Company
Northern Powergrid Holdings	Northern Powergrid Holdings Company
MidAmerican Energy Pipeline Group	Consists of Northern Natural Gas and Kern River
MidAmerican Renewables	Consists of MidAmerican Renewables, LLC and CalEnergy Philippines
CE Casecnan	CE Casecnan Water and Energy Company, Inc.
HomeServices	HomeServices of America, Inc. and its subsidiaries
ETT	Electric Transmission Texas, LLC
Utilities	PacifiCorp and MidAmerican Energy Company
Domestic Regulated Businesses	PacifiCorp, MidAmerican Energy Company, Northern Natural Gas Company and Kern River Gas Transmission Company
Berkshire Hathaway	Berkshire Hathaway Inc. and its subsidiaries
Topaz	Topaz Solar Farms LLC
Topaz Project	Topaz Solar Farms LLC's 550-megawatt solar project
Agua Caliente	Agua Caliente Solar, LLC
Agua Caliente Project	Agua Caliente Solar, LLC's 290-megawatt solar project
Bishop Hill	Bishop Hill Energy II, LLC
Bishop Hill Project	Bishop Hill Energy II, LLC's 81-MW wind-powered generating project

Certain Industry Terms	
AFUDC	Allowance for Funds Used During Construction
Dodd-Frank Reform Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gases
IPUC	Idaho Public Utilities Commission
IUB	Iowa Utilities Board
kV	Kilovolt
MW	Megawatts
OPUC	Oregon Public Utility Commission
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
UPSC	Utah Public Service Commission
WPSC	Wyoming Public Service Commission
WUTC	Washington Utilities and Transportation Commission

Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can typically be identified by the use of forward-looking words, such as "will," "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon the Company's current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside the control of the Company and could cause actual results to differ materially from those expressed or implied by such forward-looking statements. These factors include, among others:

- general economic, political and business conditions, as well as changes in laws and regulations affecting the Company's operations or related industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce facility output, accelerate facility retirements or delay facility construction or acquisition;
- the outcome of general rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies and the Company's ability to recover costs in rates in a timely manner;
- changes in economic, industry, competition or weather conditions, as well as demographic trends, that could affect customer growth and usage, electricity and natural gas supply or the Company's ability to obtain long-term contracts with customers and suppliers;
- a high degree of variance between actual and forecasted load that could impact the Company's hedging strategy and the cost of balancing its generation resources with its retail load obligations;
- performance and availability of the Company's facilities, including the impacts of outages and repairs, transmission constraints, weather and operating conditions;
- changes in prices, availability and demand for both purchases and sales of wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generating capacity and energy costs;
- the financial condition and creditworthiness of the Company's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate, the base interest rate for MEHC's and its subsidiaries' credit facilities;
- changes in MEHC's and its subsidiaries' credit ratings;
- risks relating to nuclear generation;
- the impact of derivative contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in commodity prices, interest rates and other conditions that affect the fair value of derivative contracts;
- the impact of inflation on costs and the Company's ability to recover such costs in regulated rates;
- increases in employee healthcare costs;
- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements;
- changes in the residential real estate brokerage and mortgage industries and regulations that could affect brokerage and mortgage transaction levels;
- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future facilities and infrastructure additions;
- the availability and price of natural gas in applicable geographic regions and demand for natural gas supply;
- the impact of new accounting guidance or changes in current accounting estimates and assumptions on the Company's consolidated financial results;
- the Company's ability to successfully integrate future acquired operations into its business;

- other risks or unforeseen events, including the effects of storms, floods, fires, explosions, litigation, wars, terrorism, embargoes and other catastrophic events; and
- other business or investment considerations that may be disclosed from time to time in MEHC's filings with the United States Securities and Exchange Commission or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Company are described in MEHC's filings with the United States Securities and Exchange Commission, including Part II, Item 1A and other discussions contained in this Form 10-Q. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing factors should not be construed as exclusive.

PART I

Item 1. Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
MidAmerican Energy Holdings Company
Des Moines, Iowa

We have reviewed the accompanying consolidated balance sheet of MidAmerican Energy Holdings Company and subsidiaries (the "Company") as of September 30, 2012, and the related consolidated statements of operations and comprehensive income for the three-month and nine-month periods ended September 30, 2012 and 2011, and of changes in equity and cash flows for the nine-month periods ended September 30, 2012 and 2011. These interim financial statements are the responsibility of the Company's management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of MidAmerican Energy Holdings Company and subsidiaries as of December 31, 2011, and the related consolidated statements of operations, cash flows, changes in equity, and comprehensive income for the year then ended (not presented herein); and in our report dated February 27, 2012, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2011 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
November 2, 2012

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Unaudited)

(Amounts in millions)

	As of	
	September 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,860	$ 286
Trade receivables, net	1,258	1,270
Income taxes receivable	—	456
Inventories	762	690
Other current assets	581	581
Total current assets	4,461	3,283
Property, plant and equipment, net	36,204	34,167
Goodwill	5,033	4,996
Investments and restricted cash and investments	2,076	1,948
Regulatory assets	2,770	2,835
Other assets	566	489
Total assets	$ 51,110	$ 47,718

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Unaudited) (continued)

(Amounts in millions)

	As of	
	September 30, 2012	December 31, 2011
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 1,055	$ 989
Accrued employee expenses	265	155
Accrued interest	327	326
Accrued property, income and other taxes	679	340
Short-term debt	178	865
Current portion of long-term debt	1,181	1,198
Other current liabilities	659	674
Total current liabilities	4,344	4,547
Regulatory liabilities	1,735	1,663
MEHC senior debt	4,621	4,621
Subsidiary debt	15,154	13,253
Deferred income taxes	7,556	7,076
Other long-term liabilities	2,216	2,293
Total liabilities	35,626	33,453
Commitments and contingencies (Note 10)		
Equity:		
MEHC shareholders' equity:		
Common stock - 115 shares authorized, no par value, 75 shares issued and outstanding	—	—
Additional paid-in capital	5,423	5,423
Retained earnings	10,455	9,310
Accumulated other comprehensive loss, net	(565)	(641)
Total MEHC shareholders' equity	15,313	14,092
Noncontrolling interests	171	173
Total equity	15,484	14,265
Total liabilities and equity	$ 51,110	$ 47,718

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)

(Amounts in millions)

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2012	2011	2012	2011
Operating revenue:				
Energy	$ 2,636	$ 2,535	$ 7,593	$ 7,546
Real estate	372	285	970	764
Total operating revenue	3,008	2,820	8,563	8,310
Operating costs and expenses:				
Energy:				
Cost of sales	884	897	2,576	2,709
Operating expense	653	604	1,953	1,865
Depreciation and amortization	367	324	1,072	988
Real estate	347	267	921	739
Total operating costs and expenses	2,251	2,092	6,522	6,301
Operating income	757	728	2,041	2,009
Other income (expense):				
Interest expense	(298)	(301)	(884)	(907)
Capitalized interest	15	13	37	31
Interest and dividend income	3	2	8	11
Other, net	35	17	86	63
Total other income (expense)	(245)	(269)	(753)	(802)
Income before income tax expense and equity income	512	459	1,288	1,207
Income tax expense	47	68	188	255
Equity income	30	28	61	42
Net income	495	419	1,161	994
Net income attributable to noncontrolling interests	7	7	16	15
Net income attributable to MEHC shareholders	$ 488	$ 412	$ 1,145	$ 979

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)

(Amounts in millions)

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2012	2011	2012	2011
Net income	$ 495	$ 419	$ 1,161	$ 994
Other comprehensive income (loss), net of tax:				
Unrecognized amounts on retirement benefits, net of tax of $(2), $7, $1 and $7	(5)	19	6	19
Foreign currency translation adjustment	84	(79)	113	(1)
Unrealized losses on available-for-sale securities, net of tax of $(11), $(143), $(35) and $(323)	(16)	(216)	(51)	(487)
Unrealized gains on cash flow hedges, net of tax of $7, $2, $5 and $10	11	3	8	15
Total other comprehensive income (loss), net of tax	74	(273)	76	(454)
Comprehensive income	569	146	1,237	540
Comprehensive income attributable to noncontrolling interests	7	7	16	15
Comprehensive income attributable to MEHC shareholders	$ 562	$ 139	$ 1,221	$ 525

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (Unaudited)

(Amounts in millions)

	MEHC Shareholders' Equity						
	Common		Additional Paid-in	Retained	Accumulated Other Comprehensive	Noncontrolling	Total
	Shares	Stock	Capital	Earnings	Loss, Net	Interests	Equity
Balance at December 31, 2010	75	$ —	$ 5,427	$ 7,979	$ (174)	$ 176	$ 13,408
Net income	—	—	—	979	—	15	994
Other comprehensive loss	—	—	—	—	(454)	—	(454)
Distributions	—	—	—	—	—	(19)	(19)
Other equity transactions	—	—	(4)	—	—	1	(3)
Balance at September 30, 2011	75	$ —	$ 5,423	$ 8,958	$ (628)	$ 173	$ 13,926
Balance at December 31, 2011	75	$ —	$ 5,423	$ 9,310	$ (641)	$ 173	$ 14,265
Net income	—	—	—	1,145	—	16	1,161
Other comprehensive income	—	—	—	—	76	—	76
Distributions	—	—	—	—	—	(18)	(18)
Balance at September 30, 2012	75	$ —	$ 5,423	$ 10,455	$ (565)	$ 171	$ 15,484

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)
(Amounts in millions)

	Nine-Month Periods Ended September 30, 2012	Nine-Month Periods Ended September 30, 2011
Cash flows from operating activities:		
Net income	$ 1,161	$ 994
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	1,086	997
Changes in regulatory assets and liabilities	(26)	(7)
Deferred income taxes and amortization of investment tax credits	655	475
Other, net	(55)	(54)
Changes in other operating assets and liabilities, net of effects from acquisitions:		
Trade receivables and other assets	24	60
Derivative collateral, net	64	32
Contributions to pension and other postretirement benefit plans, net	(107)	(132)
Accrued property, income and other taxes	824	395
Accounts payable and other liabilities	56	(43)
Net cash flows from operating activities	3,682	2,717
Cash flows from investing activities:		
Capital expenditures	(2,349)	(1,912)
Acquisitions, net of cash acquired	(110)	—
Purchases of available-for-sale securities	(84)	(105)
Proceeds from sales of available-for-sale securities	69	102
Equity method investments	(310)	(72)
Increase in restricted cash and investments	(45)	(7)
Other, net	12	1
Net cash flows from investing activities	(2,817)	(1,993)
Cash flows from financing activities:		
Proceeds from subsidiary debt	2,199	790
Repayments of subsidiary debt	(450)	(601)
Repayments of MEHC senior and subordinated debt	(272)	(122)
Net repayments of short-term debt	(715)	(320)
Other, net	(58)	(36)
Net cash flows from financing activities	704	(289)
Effect of exchange rate changes	5	1
Net change in cash and cash equivalents	1,574	436
Cash and cash equivalents at beginning of period	286	470
Cash and cash equivalents at end of period	$ 1,860	$ 906

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

(1) General

MidAmerican Energy Holdings Company ("MEHC") is a holding company that owns subsidiaries principally engaged in energy businesses (collectively with its subsidiaries, the "Company"). MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

The Company's operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, LLC ("MidAmerican Funding") (which primarily consists of MidAmerican Energy Company ("MidAmerican Energy")), Northern Natural Gas Company ("Northern Natural Gas"), Kern River Gas Transmission Company ("Kern River"), Northern Powergrid Holdings Company ("Northern Powergrid Holdings") (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), CalEnergy Philippines (which owns a majority interest in the Casecnan project in the Philippines), MidAmerican Renewables, LLC (which owns interests in independent power projects in the United States), and HomeServices of America, Inc. (collectively with its subsidiaries, "HomeServices"). Through these platforms, the Company owns and operates an electric utility company in the Western United States, an electric and natural gas utility company in the Midwestern United States, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of independent power projects and the second largest residential real estate brokerage firm in the United States. Northern Natural Gas and Kern River have been aggregated in the reportable segment called MidAmerican Energy Pipeline Group, and CalEnergy Philippines and MidAmerican Renewables, LLC have been aggregated in the reportable segment called MidAmerican Renewables.

The unaudited Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and the United States Securities and Exchange Commission's rules and regulations for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by GAAP for annual financial statements. Management believes the unaudited Consolidated Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the Consolidated Financial Statements as of September 30, 2012 and for the three- and nine-month periods ended September 30, 2012 and 2011. The results of operations for the three- and nine-month periods ended September 30, 2012 are not necessarily indicative of the results to be expected for the full year.

The preparation of the unaudited Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Consolidated Financial Statements. Note 2 of Notes to Consolidated Financial Statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2011 describes the most significant accounting policies used in the preparation of the Consolidated Financial Statements. There have been no significant changes in the Company's assumptions regarding significant accounting estimates and policies during the nine-month period ended September 30, 2012.

(2) New Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011-11, which amends FASB Accounting Standards Codification ("ASC") Topic 210, "Balance Sheet." The amendments in this guidance require an entity to provide quantitative disclosures about offsetting financial instruments and derivative instruments. Additionally, this guidance requires qualitative and quantitative disclosures about master netting agreements or similar agreements when the financial instruments and derivative instruments are not offset. This guidance is effective for fiscal years beginning on or after January 1, 2013, and for interim periods within those fiscal years. The Company is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Consolidated Financial Statements.

In June 2011, the FASB issued ASU No. 2011-05, which amends FASB ASC Topic 220, "Comprehensive Income." ASU No. 2011-05 provides an entity with the option to present the total of 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. Regardless of the option chosen, this guidance also requires presentation of items on the face of the financial statements that are reclassified from other comprehensive income to net income. This guidance does not change the items that must be reported in other comprehensive income, when an item of other comprehensive income must be reclassified to net income or how tax effects of each item of other comprehensive income are presented. This guidance is effective for interim and annual reporting periods beginning after December 15, 2011. In December 2011, the FASB issued ASU No. 2011-12, which also amends FASB ASC Topic 220 to defer indefinitely the ASU No. 2011-05 requirement to present items on the face of the financial statements that are reclassified from other comprehensive income to net income. ASU No. 2011-12 is also effective for interim and annual reporting periods beginning after December 15, 2011. The Company adopted this guidance on January 1, 2012 and elected the two separate but consecutive statements option.

In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC Topic 820, "Fair Value Measurements and Disclosures." The amendments in this guidance are not intended to result in a change in current accounting. ASU No. 2011-04 requires additional disclosures relating to fair value measurements categorized within Level 3 of the fair value hierarchy, including quantitative information about unobservable inputs, the valuation process used by the entity and the sensitivity of unobservable input measurements. Additionally, entities are required to disclose the level of the fair value hierarchy for assets and liabilities that are not measured at fair value in the balance sheet, but for which disclosure of the fair value is required. This guidance is effective for interim and annual reporting periods beginning after December 15, 2011. The Company adopted ASU No. 2011-04 on January 1, 2012. The adoption of this guidance did not have a material impact on the Company's disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following (in millions):

		As of	
	Depreciable Life	September 30, 2012	December 31, 2011
Regulated assets:			
Utility generation, distribution and transmission system	5-80 years	$ 41,813	$ 40,180
Interstate pipeline assets	3-80 years	6,323	6,245
		48,136	46,425
Accumulated depreciation and amortization		(15,125)	(14,390)
Regulated assets, net		33,011	32,035
Nonregulated assets:			
Independent power plants	5-30 years	677	677
Other assets	3-30 years	452	429
		1,129	1,106
Accumulated depreciation and amortization		(575)	(533)
Nonregulated assets, net		554	573
Net operating assets		33,565	32,608
Construction work-in-progress		2,639	1,559
Property, plant and equipment, net		$ 36,204	$ 34,167

Construction work-in-progress includes $2.0 billion and $1.6 billion as of September 30, 2012 and December 31, 2011, respectively, related to the construction of regulated assets.

Through October 2012, the Company completed various acquisitions totaling $235 million. The purchase price for each acquisition was allocated to the assets acquired, which relate primarily to development and construction costs for the Topaz solar project ("Topaz Project") and the Bishop Hill II wind-powered generation project ("Bishop Hill Project"), and intangible franchise contracts and goodwill for a real estate brokerage franchise business and several real estate brokerage businesses. There were no material liabilities assumed.

In September 2012, MidAmerican Renewables, through wholly-owned subsidiaries, signed a definitive agreement, subject to conditions precedent, to acquire all of the equity interests in two project companies that own the 168-MW Alta Wind VII and the 132-MW Alta Wind IX wind-powered generation projects ("Alta Wind Projects"), located in California, which are expected to be placed in service in 2012. Once completed, the Alta Wind Projects will sell all of their generation to Southern California Edison pursuant to the terms of power purchase agreements that extend to 2035. These transactions are expected to close in 2012.

(4) Fair Value Measurements

The carrying value of the Company's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. The Company has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 — Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date.

- Level 2 — Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).

- Level 3 — Unobservable inputs reflect the Company's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Company develops these inputs based on the best information available, including its own data.

The following table presents the Company's assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements				
	Level 1	**Level 2**	**Level 3**	**Other[(1)]**	**Total**
As of September 30, 2012					
Assets:					
Commodity derivatives	$ 1	$ 82	$ 19	$ (69)	$ 33
Money market mutual funds[(2)]	865	—	—	—	865
Debt securities:					
United States government obligations	103	—	—	—	103
International government obligations	—	1	—	—	1
Corporate obligations	—	30	—	—	30
Municipal obligations	—	6	—	—	6
Agency, asset and mortgage-backed obligations	—	7	—	—	7
Auction rate securities	—	—	38	—	38
Equity securities:					
United States companies	187	—	—	—	187
International companies	394	—	—	—	394
Investment funds	69	—	—	—	69
	$ 1,619	$ 126	$ 57	$ (69)	$ 1,733
Liabilities - commodity derivatives	$ (11)	$ (360)	$ (7)	$ 147	$ (231)

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other[1]	Total
As of December 31, 2011					
Assets:					
Commodity derivatives	$ 1	$ 166	$ 27	$ (147)	$ 47
Money market mutual funds[2]	164	—	—	—	164
Debt securities:					
United States government obligations	89	—	—	—	89
International government obligations	—	1	—	—	1
Corporate obligations	—	30	—	—	30
Municipal obligations	—	12	—	—	12
Agency, asset and mortgage-backed obligations	—	7	—	—	7
Auction rate securities	—	—	35	—	35
Equity securities:					
United States companies	166	—	—	—	166
International companies	489	—	—	—	489
Investment funds	64	—	—	—	64
	$ 973	$ 216	$ 62	$ (147)	$ 1,104
Liabilities - commodity derivatives	$ (37)	$ (598)	$ (4)	$ 303	$ (336)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $78 million and $156 million as of September 30, 2012 and December 31, 2011, respectively.

(2) Amounts are included in cash and cash equivalents; current investments and restricted cash and investments; and noncurrent investments and restricted cash and investments on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by the Company. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the applicable term of the Company's outstanding derivative contracts; therefore, the Company's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, the Company uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 5 for further discussion regarding the Company's risk management and hedging activities.

The Company's investments in money market mutual funds and debt and equity securities are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. The fair value of the Company's investments in auction rate securities, where there is no current liquid market, is determined using pricing models based on available observable market data and the Company's judgment about the assumptions, including liquidity and nonperformance risks, which market participants would use when pricing the asset.

The following table reconciles the beginning and ending balances of the Company's assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	Commodity Derivatives	Auction Rate Securities	Commodity Derivatives	Auction Rate Securities
2012				
Beginning balance	$ 17	$ 36	$ 23	$ 35
Changes included in earnings[1]	(2)	—	7	—
Changes in fair value recognized in other comprehensive income	—	2	3	4
Changes in fair value recognized in net regulatory assets	(3)	—	—	—
Sales	—	—	—	(1)
Settlements	—	—	(21)	—
Ending balance	$ 12	$ 38	$ 12	$ 38
2011				
Beginning balance	$ (233)	$ 37	$ (331)	$ 50
Changes included in earnings[1]	6	—	10	—
Changes in fair value recognized in other comprehensive income	—	(2)	—	—
Changes in fair value recognized in net regulatory assets	4	—	87	—
Sales	—	—	—	(15)
Settlements	15	—	26	—
Transfers from Level 2	1	—	1	—
Ending balance	$ (207)	$ 35	$ (207)	$ 35

(1) Changes included in earnings are reported as operating revenue on the Consolidated Statements of Operations. For commodity derivatives held as of September 30, 2012 and 2011, net unrealized (losses) gains included in earnings for the three-month periods ended September 30, 2012 and 2011 totaled $(2) million and $4 million, respectively, and for the nine-month periods ended September 30, 2012 and 2011, totaled $3 million and $5 million, respectively.

The Company's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of the Company's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of the Company's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of the Company's long-term debt (in millions):

	As of September 30, 2012		As of December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 20,956	$ 25,417	$ 19,072	$ 23,327

(5) Risk Management and Hedging Activities

The Company is exposed to the impact of market fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through MEHC's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. MidAmerican Energy also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. Additionally, the Company is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain. The Company does not engage in a material amount of proprietary trading activities.

Each of the Company's business platforms has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, the Company uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. The Company manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, the Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate the Company's exposure to interest rate risk. The Company does not hedge all of its commodity price, interest rate and foreign currency exchange rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in the Company's accounting policies related to derivatives. Refer to Note 4 for additional information on derivative contracts.

The following table, which reflects master netting arrangements and excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of the Company's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of September 30, 2012					
Not designated as hedging contracts[(1)]:					
Commodity assets	$ 28	$ 8	$ 48	$ 8	$ 92
Commodity liabilities	(7)	(2)	(206)	(126)	(341)
Total	21	6	(158)	(118)	(249)
Designated as hedging contracts:					
Commodity assets	6	—	3	1	10
Commodity liabilities	—	—	(22)	(15)	(37)
Total	6	—	(19)	(14)	(27)
Total derivatives	27	6	(177)	(132)	(276)
Cash collateral (payable) receivable	—	—	71	7	78
Total derivatives - net basis	$ 27	$ 6	$ (106)	$ (125)	$ (198)

	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2011					
Not designated as hedging contracts[1]:					
Commodity assets	$ 93	$ 14	$ 73	$ 13	$ 193
Commodity liabilities	(47)	(5)	(324)	(216)	(592)
Total	46	9	(251)	(203)	(399)
Designated as hedging contracts:					
Commodity assets	—	—	1	—	1
Commodity liabilities	(6)	—	(24)	(17)	(47)
Total	(6)	—	(23)	(17)	(46)
Total derivatives	40	9	(274)	(220)	(445)
Cash collateral (payable) receivable	(2)	—	114	44	156
Total derivatives - net basis	$ 38	$ 9	$ (160)	$ (176)	$ (289)

(1) The Company's commodity derivatives not designated as hedging contracts are generally included in regulated rates, and as of September 30, 2012 and December 31, 2011, a net regulatory asset of $249 million and $400 million, respectively, was recorded related to the net derivative liability of $249 million and $399 million, respectively.

Not Designated as Hedging Contracts

The following table reconciles the beginning and ending balances of the Company's net regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets, as well as amounts reclassified to earnings (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2012	2011	2012	2011
Beginning balance	$ 357	$ 498	$ 400	$ 564
Changes in fair value recognized in net regulatory assets	(31)	81	42	19
Net gains (losses) reclassified to operating revenue	10	(6)	51	2
Net losses reclassified to cost of sales	(87)	(56)	(244)	(68)
Ending balance	$ 249	$ 517	$ 249	$ 517

Designated as Hedging Contracts

The Company uses derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices for delivery to nonregulated customers, spring operational sales, natural gas storage and other transactions.

The following table reconciles the beginning and ending balances of the Company's accumulated other comprehensive loss (pre-tax) and summarizes pre-tax gains and losses on derivative contracts designated and qualifying as cash flow hedges recognized in other comprehensive income ("OCI"), as well as amounts reclassified to earnings (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2012	2011	2012	2011
Beginning balance[1]	$ 49	$ 15	$ 46	$ 37
Changes in fair value recognized in OCI	(18)	(12)	12	(26)
Net gains reclassified to operating revenue	—	1	—	2
Net (losses) gains reclassified to cost of sales	(4)	3	(31)	(6)
Ending balance[1]	$ 27	$ 7	$ 27	$ 7

(1) Certain derivative contracts, principally interest rate locks, have settled and the fair value at the date of settlement remains in accumulated other comprehensive income ("AOCI") and is recognized in earnings when the forecasted transactions impact earnings.

Realized gains and losses on hedges and hedge ineffectiveness are recognized in income as operating revenue, cost of sales, operating expense or interest expense depending upon the nature of the item being hedged. For the three- and nine-month periods ended September 30, 2012 and 2011, hedge ineffectiveness was insignificant. As of September 30, 2012, the Company had cash flow hedges with expiration dates extending through May 2032 and $19 million of pre-tax net unrealized losses are forecasted to be reclassified from AOCI into earnings over the next twelve months as contracts settle.

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of (in millions):

	Unit of Measure	September 30, 2012	December 31, 2011
Electricity (sales) purchases	Megawatt hours	(2)	6
Natural gas purchases	Decatherms	136	183
Fuel purchases	Gallons	4	19

Credit Risk

The Utilities extend unsecured credit to other utilities, energy marketing companies, financial institutions and other market participants in conjunction with their wholesale energy supply and marketing activities. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with the counterparty.

The Utilities analyze the financial condition of each significant wholesale counterparty before entering into any transactions, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of wholesale counterparties, the Utilities enter into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed fees for delayed payments. If required, the Utilities exercise rights under these arrangements, including calling on the counterparty's credit support arrangement.

MidAmerican Energy also has potential indirect credit exposure to other market participants in the regional transmission organization ("RTO") markets where it actively participates, including the Midwest Independent Transmission System Operator, Inc. and the PJM Interconnection, L.L.C. In the event of a default by a RTO market participant on its market-related obligations, losses are allocated among all other market participants in proportion to each participant's share of overall market activity during the period of time the loss was incurred, diversifying MidAmerican Energy's exposure to credit losses from individual participants. Transactional activities of MidAmerican Energy and other participants in organized RTO markets are governed by credit policies specified in each respective RTO's governing tariff or related business practices. Credit policies of RTO's, which have been developed through extensive stakeholder participation, generally seek to minimize potential loss in the event of a market participant default without unnecessarily inhibiting access to the marketplace. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain provisions that require MEHC's subsidiaries, principally the Utilities, to maintain specific credit ratings from one or more of the major credit rating agencies on their unsecured debt. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in the subsidiary's creditworthiness. These rights can vary by contract and by counterparty. As of September 30, 2012, these subsidiaries' credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of the Company's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $344 million and $571 million as of September 30, 2012 and December 31, 2011, respectively, for which the Company had posted collateral of $68 million and $125 million, respectively, in the form of cash deposits and letters of credit. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of September 30, 2012 and December 31, 2011, the Company would have been required to post $222 million and $332 million, respectively, of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

(6) Investments and Restricted Cash and Investments

Investments and restricted cash and investments consists of the following (in millions):

	As of	
	September 30, 2012	December 31, 2011
Investments:		
BYD Company Limited common stock	$ 392	$ 488
Rabbi trusts	308	290
Other	105	99
Total investments	805	877
Equity method investments:		
Electric Transmission Texas, LLC	317	221
CE Generation, LLC	248	255
Bridger Coal Company	195	204
Agua Caliente Solar, LLC	62	—
Other	65	52
Total equity method investments	887	732
Restricted cash and investments:		
Nuclear decommissioning trust funds	338	308
Other	127	82
Total restricted cash and investments	465	390
Total investments and restricted cash and investments	2,157	1,999
Less current portion	(81)	(51)
Noncurrent portion	$ 2,076	$ 1,948

Investments

MEHC's investment in BYD Company Limited common stock is accounted for as an available-for-sale security with changes in fair value recognized in AOCI. As of September 30, 2012 and December 31, 2011, the fair value of MEHC's investment in BYD Company Limited common stock was $392 million and $488 million, respectively, which resulted in a pre-tax unrealized gain of $160 million and $256 million as of September 30, 2012 and December 31, 2011, respectively.

Equity Method Investments

In January 2012, MEHC, through an indirect wholly-owned subsidiary, acquired from NRG Energy, Inc. a 49% equity interest in Agua Caliente Solar, LLC ("Agua Caliente"), the developer and owner of a solar project in Arizona. As of September 30, 2012, the equity investment is net of investment tax credits totaling $164 million.

(7) Recent Financing Transactions

Long-Term Debt

In January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 2022 and $300 million of its 4.10% First Mortgage Bonds due February 2042. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes. In March 2012, PacifiCorp issued an additional $100 million of its 2.95% First Mortgage Bonds due February 2022. The net proceeds were used to redeem $84 million of tax-exempt bond obligations prior to scheduled maturity with a weighted average interest rate of 5.7%, repay short-term debt and for general corporate purposes.

In February 2012, Topaz Solar Farms, LLC ("Topaz") issued $850 million of the 5.75% Series A Senior Secured Notes. The principal of the notes amortize beginning September 2015 with a final maturity in September 2039. The net proceeds will be used to fund the costs and expenses related to the development, construction and financing of the Topaz Project. Any unused amounts will be invested or, in certain circumstances, loaned to MEHC. As of September 30, 2012, $421 million was loaned to MEHC.

In June 2012, MidAmerican Energy redeemed $275 million of its 5.125% Senior Notes due January 2013 at a redemption price determined in accordance with the terms of the indenture.

In July 2012, Northern Powergrid (Yorkshire) plc issued £150 million of its 4.375% Bonds due July 2032. The net proceeds will be used for general corporate purposes.

In August 2012, Northern Natural Gas issued $250 million of its 4.10% Senior Bonds due September 2042. The net proceeds were used to partially repay its $300 million, 5.375% Senior Notes due October 2012.

In August 2012, Bishop Hill issued $120 million of its 5.125% Senior Secured Fixed Rate Notes. The principal of the notes amortize beginning March 2013 with a final maturity in March 2032. The net proceeds will be used to fund the costs and expenses related to the development, construction and financing of the Bishop Hill Project.

In conjunction with the construction of wind-powered generating facilities in 2012, MidAmerican Energy has accrued as construction work-in-progress amounts it is not contractually obligated to pay until December 2015. The amounts ultimately payable are discounted at 1.43% and recognized upon delivery of the equipment as long-term debt. The discount is being amortized as interest expense over the period until payment is due using the effective interest method. As of September 30, 2012, $306 million of such debt from the 2012 wind-powered generation projects, net of associated discount, was outstanding.

Credit Facilities

In August 2012, Northern Powergrid Holdings replaced its existing £150 million unsecured credit facility expiring in March 2013 with a £150 million unsecured credit facility expiring in August 2017. The replacement credit facility has a variable interest rate based on the sterling London Interbank Offered Rate ("LIBOR") plus a spread that varies based on its credit ratings. This facility is for general corporate purposes. As of September 30, 2012, Northern Powergrid Holdings had no borrowings outstanding under this credit facility. The credit facility requires that Northern Powergrid Holdings' ratio of consolidated senior total net debt, including current maturities, to regulated asset value not exceed 0.8 to 1.0 at Northern Powergrid Holdings and 0.65 to 1.0 at Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc as of June 30 and December 31. Additionally, Northern Powergrid Holdings' interest coverage ratio shall not be less than 2.5 to 1.0.

In June 2012, MEHC entered into a $600 million senior unsecured credit facility expiring in June 2017. The credit facility has a variable interest rate based on LIBOR or a base rate, at MEHC's option, plus a spread that varies based on MEHC's credit ratings for its senior unsecured long-term debt securities. This facility is for general corporate purposes and also supports commercial paper and letters of credit for the benefit of certain subsidiaries and affiliates. As of September 30, 2012, MEHC had $140 million of commercial paper borrowings outstanding at an average rate of 0.4%. The credit facility requires that MEHC's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.70 to 1.0 as of the last day of each quarter. This facility, along with its existing $479 million senior unsecured credit facility expiring in July 2013, supports MEHC's $1 billion commercial paper program.

In June 2012, PacifiCorp replaced its existing $635 million unsecured credit facility expiring in October 2012 with a $600 million unsecured credit facility expiring in June 2017. The replacement credit facility has a variable interest rate based on LIBOR or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. This facility is for general corporate purposes including supporting PacifiCorp's commercial paper program and provides for the issuance of letters of credit. As of September 30, 2012, PacifiCorp had no borrowings outstanding under this credit facility. The credit facility requires that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

In connection with its offering, Topaz entered into a letter of credit and reimbursement facility in an aggregate principal amount of $345 million. Letters of credit issued under the letter of credit facility will be used to (a) provide security under the power purchase agreement and large generator interconnection agreements, (b) fund the debt service reserve requirement and the operation and maintenance debt service reserve requirement, (c) provide security for remediation and mitigation liabilities, and (d) provide security in respect of conditional use permit sales tax obligations. As of September 30, 2012, Topaz had $56 million of letters of credit issued under this facility.

Pursuant to an equity funding and contribution agreement, MEHC has committed to provide Agua Caliente with funding for (a) base equity contributions of up to an aggregate amount of $303 million for the construction of the Agua Caliente Project, and (b) transmission upgrade costs. In January 2012, MEHC entered into a $303 million letter of credit facility related to its funding commitments. The equity funding and contribution agreement and the letter of credit commitment decreases as equity is contributed to the Agua Caliente Project. As of September 30, 2012, the balance of the commitment was $169 million.

(8) Employee Benefit Plans

Domestic Operations

Net periodic benefit cost for the domestic pension and other postretirement benefit plans included the following components (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2012	2011	2012	2011
Pension:				
Service cost	$ 6	$ 6	$ 19	$ 20
Interest cost	24	26	72	78
Expected return on plan assets	(30)	(29)	(89)	(88)
Net amortization	10	6	29	15
Net periodic benefit cost	$ 10	$ 9	$ 31	$ 25
Other postretirement:				
Service cost	$ 3	$ 3	$ 8	$ 8
Interest cost	9	10	27	31
Expected return on plan assets	(11)	(12)	(32)	(33)
Net amortization	1	4	1	12
Net periodic benefit cost	$ 2	$ 5	$ 4	$ 18

Employer contributions to the domestic pension and other postretirement benefit plans are expected to be $114 million and $9 million, respectively, during 2012. As of September 30, 2012, $111 million and $4 million of contributions had been made to the domestic pension and other postretirement benefit plans, respectively.

Foreign Operations

Net periodic benefit cost for the United Kingdom pension plan included the following components (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2012	2011	2012	2011
Service cost	$ 5	$ 5	$ 15	$ 15
Interest cost	21	24	64	70
Expected return on plan assets	(26)	(29)	(79)	(87)
Net amortization	11	9	33	27
Net periodic benefit cost	$ 11	$ 9	$ 33	$ 25

Employer contributions to the United Kingdom pension plan are expected to be £50 million during 2012. As of September 30, 2012, £38 million, or $59 million, of contributions had been made to the United Kingdom pension plan.

(9) Income Taxes

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense is as follows:

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2012	2011	2012	2011
Federal statutory income tax rate	35%	35%	35%	35%
Federal and state income tax credits	(16)	(13)	(13)	(11)
State income tax, net of federal income tax benefit	2	2	2	2
Change in United Kingdom corporate income tax rate	(7)	(9)	(3)	(3)
Income tax effect of foreign income	(3)	(2)	(2)	(2)
Effects of ratemaking	(2)	(1)	(3)	(1)
Other, net	—	3	(1)	1
Effective income tax rate	9%	15%	15%	21%

Federal and state income tax credits primarily relate to production tax credits at the Utilities. The Utilities' wind-powered generating facilities are eligible for federal renewable electricity production tax credits for 10 years from the date the facilities were placed in service.

In July 2012, the Company recognized $38 million of deferred income tax benefits upon the enactment of a reduction in the United Kingdom corporate income tax rate from 25% to 24% effective April 1, 2012, and a further reduction to 23% effective April 1, 2013. In July 2011, the Company recognized $40 million of deferred income tax benefits upon the enactment of a reduction in the United Kingdom corporate income tax rate from 27% to 26% effective April 1, 2011, and a further reduction to 25% effective April 1, 2012.

Berkshire Hathaway includes the Company in its United States federal income tax return. As of September 30, 2012, the Company had income taxes payable to Berkshire Hathaway of $341 million and as of December 31, 2011, the Company had income taxes receivable from Berkshire Hathaway of $456 million.

(10) Commitments and Contingencies

Legal Matters

The Company is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. The Company is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

USA Power

In October 2005, prior to MEHC's ownership of PacifiCorp, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in the Third District Court of Salt Lake County, Utah ("Third District Court") by USA Power, LLC, USA Power Partners, LLC and Spring Canyon Energy, LLC (collectively, the "Plaintiff"). The Plaintiff's complaint alleged that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accused PacifiCorp of breach of contract and related claims in regard to the Plaintiff's 2002 and 2003 proposals to build a natural gas-fueled generating facility in Juab County, Utah. In October 2007, the Third District Court granted PacifiCorp's motion for summary judgment on all counts and dismissed the Plaintiff's claims in their entirety. In February 2008, the Plaintiff filed a petition requesting consideration by the Utah Supreme Court on two of its five claims. In May 2010, the Utah Supreme Court remanded the case back to the Third District Court for further consideration, which led to a trial that began in April 2012. On May 21, 2012, the jury reached a verdict in favor of the Plaintiff on both claims. The jury awarded the Plaintiff breach of contract damages of $18 million and unjust enrichment damages of $113 million against PacifiCorp; however, a final judgment has not been rendered on the verdict. On May 24, 2012, the Plaintiff filed a motion seeking exemplary damages. Under the Utah Uniform Trade Secrets law, the judge may award exemplary damages in an additional amount not to exceed twice the original award. The Plaintiff also filed a motion to seek recovery of attorneys' fees in an amount equal to 40% of all amounts ultimately awarded in the case. On October 15, 2012, PacifiCorp filed post-trial motions for a judgment notwithstanding the verdict and a new trial (collectively, "PacifiCorp's post-trial motions"). The trial judge stayed briefing on the Plaintiff's motions, pending resolution of PacifiCorp's post-trial motions. PacifiCorp strongly disagrees with the verdict and will aggressively pursue available options in an effort to vacate or reduce the verdict, including, if necessary, appellate measures. If the judge grants either of PacifiCorp's post-trial motions, then the Plaintiff's motions for exemplary damages and attorneys' fees will be moot. If the judge does not grant either of PacifiCorp's post-trial motions, then the judge will set a schedule for PacifiCorp to respond to the Plaintiff's motions for exemplary damages and attorneys' fees. In the event the judge does not grant either of PacifiCorp's post-trial motions, PacifiCorp expects a decision on the Plaintiff's motions for exemplary damages and attorneys' fees in 2013. PacifiCorp believes there is meritorious basis for such post-trial motions and appeal. PacifiCorp has accrued its estimated liability as of September 30, 2012, and believes the ultimate outcome of the case will not be material to PacifiCorp's consolidated financial results; however this matter could have a material effect on PacifiCorp's consolidated financial results in the event of an unfavorable outcome. Any payment of damages will be at the end of the appeal process, which could take several years.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company's current and future operations. The Company believes it is in material compliance with all applicable laws and regulations.

Hydroelectric Relicensing

PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses with the Federal Energy Regulatory Commission ("FERC"). In February 2010, PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the State of California, the State of Oregon and various other governmental and non-governmental settlement parties signed the Klamath Hydroelectric Settlement Agreement ("KHSA"). Among other things, the KHSA provides that the United States Department of the Interior conduct scientific and engineering studies to assess whether removal of the Klamath hydroelectric system's mainstem dams is in the public interest and will advance restoration of the Klamath Basin's salmonid fisheries. If it is determined that dam removal should proceed, dam removal is expected to commence no earlier than 2020.

Under the KHSA, PacifiCorp and its customers are protected from uncapped dam removal costs and liabilities. For dam removal to occur, federal legislation consistent with the KHSA must be enacted to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. If Congress does not enact legislation, then PacifiCorp will resume relicensing with the FERC. In November 2011, bills were introduced in both chambers of the United States Congress that, if passed, would enact the KHSA and a companion agreement that seeks to resolve other water-related conflicts and restore habitat in the Klamath basin.

In addition, the KHSA limits PacifiCorp's contribution to dam removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. An additional $250 million for dam removal costs is expected to be raised through a California bond measure or other appropriate State of California financing mechanism. If dam removal costs exceed $200 million and if the State of California is unable to raise the additional funds necessary for dam removal costs, sufficient funds would need to be provided by an entity other than PacifiCorp in order for the KHSA and dam removal to proceed.

PacifiCorp has begun collection of surcharges from Oregon customers for their share of dam removal costs, as approved by the Oregon Public Utility Commission ("OPUC"), and is depositing the proceeds into trust accounts maintained by the OPUC. PacifiCorp has begun collection of surcharges from California customers for their share of dam removal costs, as approved by the California Public Utilities Commission ("CPUC"), and is depositing the proceeds into trust accounts maintained by the CPUC. PacifiCorp is authorized to collect the surcharges through 2019.

As of September 30, 2012, PacifiCorp's assets included $118 million of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs. PacifiCorp has received approvals from the OPUC, the CPUC and the Wyoming Public Service Commission to depreciate the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs through the expected dam removal date. The depreciation rate changes were effective January 1, 2011 and will allow for full depreciation of the assets by December 2019 for those jurisdictions. PacifiCorp filed for consistent ratemaking treatment in Idaho and Washington general rate cases, which were settled in January 2012 and March 2012, respectively, without a decision on this matter. As part of the September 2012 Utah general rate case order, the Utah Public Service Commission approved recovery of Utah's share of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs through December 31, 2022.

Guarantees

The Company has entered into guarantees as part of the normal course of business and the sale of certain assets. These guarantees are not expected to have a material impact on the Company's consolidated financial results.

(11) Components of Accumulated Other Comprehensive Loss, Net

The following table shows the change in accumulated other comprehensive loss attributable to MEHC shareholders by each component of other comprehensive income (loss), net of applicable income taxes, for the nine-month period ended September 30, 2012 (in millions):

	Unrecognized Amounts on Retirement Benefits	Foreign Currency Translation Adjustment	Unrealized Gains on Available-For-Sale Securities	Unrealized Gains on Cash Flow Hedges	Accumulated Other Comprehensive Loss Attributable To MEHC Shareholders, Net
Balance, December 31, 2011	$ (491)	$ (307)	$ 142	$ 15	$ (641)
Other comprehensive income (loss)	6	113	(51)	8	76
Balance, September 30, 2012	$ (485)	$ (194)	$ 91	$ 23	$ (565)

(12) Segment Information

Northern Natural Gas and Kern River have been aggregated in the reportable segment called MidAmerican Energy Pipeline Group, and CalEnergy Philippines and MidAmerican Renewables, LLC have been aggregated in the reportable segment called MidAmerican Renewables. Prior year amounts have been changed to conform to the current presentation. The Company's reportable segments with foreign operations include Northern Powergrid Holdings, whose business is principally in Great Britain, and MidAmerican Renewables, whose business includes operations in the Philippines. Intersegment eliminations and adjustments, including the allocation of goodwill, have been made. Information related to the Company's reportable segments is shown below (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2012	2011	2012	2011
Operating revenue:				
PacifiCorp	$ 1,327	$ 1,198	$ 3,671	$ 3,408
MidAmerican Funding	828	866	2,411	2,650
MidAmerican Energy Pipeline Group	203	202	698	697
Northern Powergrid Holdings	240	237	747	727
MidAmerican Renewables	51	45	112	107
HomeServices	372	285	970	764
MEHC and Other[(1)]	(13)	(13)	(46)	(43)
Total operating revenue	$ 3,008	$ 2,820	$ 8,563	$ 8,310
Depreciation and amortization:				
PacifiCorp	$ 164	$ 154	$ 488	$ 465
MidAmerican Funding	107	79	300	248
MidAmerican Energy Pipeline Group	48	44	144	137
Northern Powergrid Holdings	44	42	127	125
MidAmerican Renewables	7	8	22	23
HomeServices	4	3	14	9
MEHC and Other[(1)]	(3)	(3)	(9)	(10)
Total depreciation and amortization	$ 371	$ 327	$ 1,086	$ 997
Operating income:				
PacifiCorp	$ 382	$ 320	$ 917	$ 858
MidAmerican Funding	139	148	311	346
MidAmerican Energy Pipeline Group	68	79	322	320
Northern Powergrid Holdings	118	136	406	431
MidAmerican Renewables	34	34	66	67
HomeServices	25	18	49	25
MEHC and Other[(1)]	(9)	(7)	(30)	(38)
Total operating income	757	728	2,041	2,009
Interest expense	(298)	(301)	(884)	(907)
Capitalized interest	15	13	37	31
Interest and dividend income	3	2	8	11
Other, net	35	17	86	63
Total income before income tax expense and equity income	$ 512	$ 459	$ 1,288	$ 1,207

	Three-Month Periods Ended September 30, 2012	Three-Month Periods Ended September 30, 2011	Nine-Month Periods Ended September 30, 2012	Nine-Month Periods Ended September 30, 2011
Interest expense:				
PacifiCorp	$ 98	$ 106	$ 294	$ 309
MidAmerican Funding	41	45	126	138
MidAmerican Energy Pipeline Group	24	25	70	78
Northern Powergrid Holdings	36	38	103	116
MidAmerican Renewables	21	3	50	13
HomeServices	1	—	1	—
MEHC and Other(1)	77	84	240	253
Total interest expense	$ 298	$ 301	$ 884	$ 907

	As of September 30, 2012	As of December 31, 2011
Total assets:		
PacifiCorp	$ 22,813	$ 22,364
MidAmerican Funding	13,105	12,430
MidAmerican Energy Pipeline Group	5,107	4,854
Northern Powergrid Holdings	6,314	5,690
MidAmerican Renewables	2,089	890
HomeServices	786	649
MEHC and Other(1)	896	841
Total assets	$ 51,110	$ 47,718

(1) The remaining differences between the segment amounts and the consolidated amounts described as "MEHC and Other" relate principally to intersegment eliminations for operating revenue and, for the other items presented, to (a) corporate functions, including administrative costs, interest expense, corporate cash and investments and related interest income and (b) intersegment eliminations.

The following table shows the change in the carrying amount of goodwill by reportable segment for the nine-month period ended September 30, 2012 (in millions):

	PacifiCorp	MidAmerican Funding	MidAmerican Energy Pipeline Group	Northern Powergrid Holdings	MidAmerican Renewables	Home-Services	Total
Balance, December 31, 2011	$ 1,126	$ 2,102	$ 205	$ 1,097	$ 71	$ 395	$ 4,996
Foreign currency translation	—	—	—	33	—	—	33
Other	—	—	(20)	—	—	24	4
Balance, September 30, 2012	$ 1,126	$ 2,102	$ 185	$ 1,130	$ 71	$ 419	$ 5,033

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of the Company during the periods included herein. Explanations include management's best estimate of the impacts of weather, customer growth and other factors. This discussion should be read in conjunction with the Company's historical unaudited Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q. The Company's actual results in the future could differ significantly from the historical results.

The Company's operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding (which primarily consists of MidAmerican Energy), Northern Natural Gas, Kern River, Northern Powergrid Holdings (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), CalEnergy Philippines (which owns a majority interest in the Casecnan project in the Philippines), MidAmerican Renewables, LLC (which owns interests in independent power projects in the United States), and HomeServices. Through these platforms, the Company owns and operates an electric utility company in the Western United States, an electric and natural gas utility company in the Midwestern United States, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of independent power projects and the second largest residential real estate brokerage firm in the United States. Northern Natural Gas and Kern River have been aggregated in the reportable segment called MidAmerican Energy Pipeline Group, and CalEnergy Philippines and MidAmerican Renewables, LLC have been aggregated in the reportable segment called MidAmerican Renewables. The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to the Company's significant accounting policies. The differences between the reportable segment amounts and the consolidated amounts, described as "MEHC and Other," relate principally to corporate functions, including administrative costs and intersegment eliminations.

Results of Operations for the Third Quarter and First Nine Months of 2012 and 2011

Overview

Net income attributable to MEHC shareholders for the three-month period ended September 30, 2012, was $488 million, an increase of $76 million, or 18%, compared to 2011. PacifiCorp's net income was $212 million for 2012, an increase of $42 million, or 25%, compared to 2011 as higher retail prices approved by regulators, higher margins from warmer temperatures and lower interest expense were partially offset by the net impact of the Utah rate case settlement in 2011 and higher depreciation and amortization. Net income at MidAmerican Funding was $136 million for 2012, an increase of $32 million, or 31%, compared to 2011 due to income tax benefits from higher production tax credits primarily from additional wind generation placed in service in late 2011 and the effects of ratemaking. Additionally, improvements in regulated electric margins from adjustment clauses and warmer temperatures were more than offset by higher costs associated with the wind assets placed in service. Net income at MidAmerican Energy Pipeline Group was $31 million for 2012, a decrease of $9 million, or 23%, compared to 2011 as higher revenue from Kern River's expansion projects, higher transportation revenue at Northern Natural Gas and a positive litigation settlement were more than offset by higher operating expense and depreciation and lower AFUDC associated with Kern River's expansion projects. Northern Powergrid Holdings' net income was $105 million for 2012, a decrease of $13 million, or 11%, compared to 2011 as higher distribution rates were more than offset by a favorable movement in regulatory provisions in 2011 and higher operating expense. MidAmerican Renewables' net income was $20 million for 2012, a decrease of $18 million, or 47%, compared to 2011 due to lower equity earnings at CE Generation from lower energy rates and higher interest expense related to the Topaz project financing, which was offset by higher equity earnings due to the acquisition of a 49% interest in Agua Caliente in January 2012. HomeServices' net income for 2012 was $18 million, an increase of $5 million, or 38%, compared to 2011 due to higher revenue and margins from higher closed units, partially offset by higher operating expenses. MEHC and Other net loss of $34 million improved $37 million for 2012 compared to 2011 due to the cessation of purchase price pension amortization in 2011, certain income tax benefits and lower interest expense.

Net income attributable to MEHC shareholders for the nine-month period ended September 30, 2012, was $1.145 billion, an increase of $166 million, or 17%, compared to 2011. PacifiCorp's net income was $493 million for 2012, an increase of $67 million, or 16%, compared to 2011 as higher retail prices approved by regulators, higher margins from warmer temperatures, lower interest expense and higher AFUDC were partially offset by higher energy costs, higher operating expense and higher depreciation and amortization. Net income at MidAmerican Funding was $284 million for 2012, an increase of $67 million, or 31%, compared to 2011 due to income tax benefits from higher production tax credits primarily from additional wind-powered generation placed in service in late 2011 and the effects of ratemaking. Additionally, improvements in regulated electric margins, from adjustment clauses and warmer temperatures, and lower interest expense were more than offset by higher costs associated with the wind assets placed in service and lower regulated gas margins. Net income at MidAmerican Energy Pipeline Group was $159 million for 2012, a decrease of $2 million, or 1%, compared to 2011 as higher revenue from Kern River's expansion projects, higher transportation and storage revenue at Northern Natural Gas and a positive litigation settlement were more than offset by higher operating expense and depreciation and lower AFUDC associated with Kern River's expansion projects. Northern Powergrid Holdings' net income was $270 million for 2012, a decrease of $8 million, or 3%, compared to 2011 as higher distribution rates and lower interest expense were more than offset by a favorable movement in regulatory provisions in 2011 and higher operating expense. MidAmerican Renewables' net income was $26 million for 2012, a decrease of $33 million, or 56% compared to 2011 primarily due to higher interest expense related to the Topaz project financing and lower equity earnings at CE Generation from lower energy rates, partially offset by higher equity earnings due to the acquisition of a 49% interest in Agua Caliente in January 2012. HomeServices' net income for 2012 was $38 million, an increase of $18 million, or 90%, compared to 2011 due to higher revenue and margins from higher closed units and average home sale prices, partially offset by higher operating expenses. MEHC and Other net loss of $125 million improved $57 million for 2012 compared to 2011 due to the cessation of purchase price pension amortization in 2011, lower interest expense, certain income tax benefits and higher equity income at ETT.

Reportable Segment Results

Operating revenue and operating income for the Company's reportable segments are summarized as follows (in millions):

	Third Quarter				First Nine Months			
	2012	2011	Change		2012	2011	Change	
Operating revenue:								
PacifiCorp	$ 1,327	$ 1,198	$ 129	11%	$ 3,671	$ 3,408	$ 263	8%
MidAmerican Funding	828	866	(38)	(4)	2,411	2,650	(239)	(9)
MidAmerican Energy Pipeline Group	203	202	1	—	698	697	1	—
Northern Powergrid Holdings	240	237	3	1	747	727	20	3
MidAmerican Renewables	51	45	6	13	112	107	5	5
HomeServices	372	285	87	31	970	764	206	27
MEHC and Other	(13)	(13)	—	—	(46)	(43)	(3)	(7)
Total operating revenue	$ 3,008	$ 2,820	$ 188	7	$ 8,563	$ 8,310	$ 253	3
Operating income:								
PacifiCorp	$ 382	$ 320	$ 62	19%	$ 917	$ 858	$ 59	7%
MidAmerican Funding	139	148	(9)	(6)	311	346	(35)	(10)
MidAmerican Energy Pipeline Group	68	79	(11)	(14)	322	320	2	1
Northern Powergrid Holdings	118	136	(18)	(13)	406	431	(25)	(6)
MidAmerican Renewables	34	34	—	—	66	67	(1)	(1)
HomeServices	25	18	7	39	49	25	24	96
MEHC and Other	(9)	(7)	(2)	(29)	(30)	(38)	8	21
Total operating income	$ 757	$ 728	$ 29	4	$ 2,041	$ 2,009	$ 32	2

PacifiCorp

Operating revenue increased $129 million for the third quarter of 2012 compared to 2011 due to an increase in retail revenue of $105 million and higher renewable energy credit revenue of $42 million, partially offset by lower electric wholesale revenue of $22 million as a result of lower average prices and volumes. The increase in retail revenue was due to higher prices approved by regulators of $82 million and higher retail customer load totaling $23 million due to the impacts of hot weather in Utah, partially offset by lower industrial customer load in Wyoming and Oregon as certain large customers elected to self-generate their own power. The higher renewable energy credit revenue in 2012 was due to the Utah general rate case settlement in 2011 ("Utah general rate case settlement"), which resulted in a $30 million decrease to operating revenue in 2011. The Utah general rate case settlement provided for a $30 million credit to customers for the refund of renewable energy credit sales that substantially occurred prior to 2011 and that were credited to Utah customer's bills over the period from September 2011 through May 2012 (the "Utah renewable energy credit adjustment").

Operating income increased $62 million for the third quarter of 2012 compared to 2011 due to the higher operating revenue and lower operating expense of $4 million, partially offset by higher energy costs of $61 million and higher depreciation and amortization of $10 million due to higher plant in service. Energy costs increased due to lower deferral of incurred power costs of $54 million and higher net fuel costs of $8 million. The Utah general rate case settlement resulted in lower energy costs of $60 million recognized in 2011 and provided for the recovery of $60 million of previously incurred net power costs in excess of amounts included in base rates to be recovered from Utah customers over a three-year period beginning on June 1, 2012 (the "Utah net power cost recovery adjustment"). The $8 million of higher net fuel costs was due to higher unit coal costs and increased thermal generation, partially offset by lower unit natural gas costs.

Operating revenue increased $263 million for the first nine months of 2012 compared to 2011 due to an increase in retail revenue of $229 million, higher renewable energy credit revenue of $63 million, partially offset by lower electric wholesale revenue of $35 million on lower average prices. The increase in retail revenue was due to higher prices approved by regulators of $191 million and $38 million of higher retail customer load. The increase in customer load is due to the impacts of hot weather in Utah and higher irrigation customer load in Idaho, partially offset by lower industrial customer load in Wyoming and Oregon as certain large customers elected to self-generate their own power and lower residential customer load in Oregon. The Utah general rate case settlement resulted in $50 million of higher renewable energy credit revenue in 2012 as compared to 2011 due to the impact of the Utah renewable energy credit adjustment of $30 million recorded in 2011 and $20 million in amortization of the Utah renewable energy credit adjustment, which was offset in operating revenue through lower rates charged to retail customers.

Operating income increased $59 million for the first nine months of 2012 compared to 2011 due to the higher operating revenue, partially offset by higher energy costs of $156 million, higher operating expense of $24 million and higher depreciation and amortization of $23 million. Energy costs increased due to higher net fuel and purchased electricity costs of $84 million and the impact of the Utah general rate case settlement on deferred power costs of $67 million. The higher net fuel and purchased electricity costs were due to increased thermal generation, higher cost of purchased electricity and the higher unit cost of coal, partially offset by lower unit natural gas costs. The impact of the Utah general rate case settlement on deferred power costs was due to the Utah net power cost recovery adjustment of $60 million recorded in 2011 and $7 million in amortization of the Utah net power cost recovery adjustment, which was offset in operating income through higher rates charged to customers. Operating expense increased due to charges in 2012 related to litigation, damage claims, the impairment of certain pre-construction costs for environmental projects at a coal-fueled generating facility and higher property taxes due to higher plant in service, partially offset by lower thermal generating facility maintenance.

MidAmerican Funding

MidAmerican Funding's operating revenue and operating income are summarized as follows (in millions):

	Third Quarter				First Nine Months			
	2012	2011	Change		2012	2011	Change	
Operating revenue:								
Regulated electric	$ 511	$ 487	$ 24	5 %	$ 1,295	$ 1,276	$ 19	1 %
Regulated natural gas	87	99	(12)	(12)	441	562	(121)	(22)
Nonregulated and other	230	280	(50)	(18)	675	812	(137)	(17)
Total operating revenue	$ 828	$ 866	$ (38)	(4)	$ 2,411	$ 2,650	$ (239)	(9)
Operating income:								
Regulated electric	$ 129	$ 133	$ (4)	(3)%	$ 243	$ 248	$ (5)	(2)%
Regulated natural gas	(3)	(1)	(2)	*	28	48	(20)	(42)
Nonregulated and other	13	16	(3)	(19)	40	50	(10)	(20)
Total operating income	$ 139	$ 148	$ (9)	(6)	$ 311	$ 346	$ (35)	(10)

* Not meaningful

Regulated electric operating revenue increased $24 million for the third quarter of 2012 compared to 2011 due to higher retail revenue of $28 million, partially offset by lower wholesale and other revenue of $4 million. Retail revenue increased due to new adjustment clauses in Iowa and Illinois totaling $17 million and a 2.5% increase in retail customer load as a result of abnormally hot weather in 2012 and customer growth. Wholesale and other revenue were lower as volumes decreased 7.0%.

Regulated electric operating income decreased $4 million for the third quarter of 2012 compared to 2011 as the higher revenue and lower energy costs of $11 million were more than offset by higher depreciation of $27 million and operating costs of $10 million due to additional wind-powered generation placed in service in late 2011 and higher revenue sharing of $7 million included in depreciation and amortization. Energy costs decreased due to lower purchased power prices and volumes, lower coal generation and the additional wind-powered generation.

Regulated natural gas operating revenue decreased $12 million for the third quarter of 2012 compared to 2011 due to a lower average per-unit cost of gas sold, resulting in lower cost of sales. Regulated natural gas operating income decreased $2 million for the third quarter of 2012 compared to 2011 due to higher operating expense.

Nonregulated and other operating revenue decreased $50 million for the third quarter of 2012 compared to 2011 due to lower electricity prices and volumes and lower natural gas prices, partially offset by higher natural gas volumes. Nonregulated and other operating income decreased $3 million for the third quarter of 2012 compared to 2011 due to lower electric margins.

Regulated electric operating revenue increased $19 million for the first nine months of 2012 compared to 2011 due to higher retail revenue of $37 million, partially offset by lower wholesale and other revenue of $18 million. Retail revenue increased due to new adjustment clauses in Iowa and Illinois totaling $30 million and a 0.5% increase in retail customer load as a result of abnormally hot weather. Wholesale and other revenue was lower due to an 8.7% decrease in average market prices.

Regulated operating income decreased $5 million for the first nine months of 2012 compared to 2011 as the higher revenue and lower energy costs of $38 million were more than offset by higher depreciation of $51 million and operating costs of $11 million due to additional wind-powered generation placed in service in late 2011 and higher revenue sharing of $16 million included in depreciation and amortization. Energy costs decreased due to lower purchased power prices and volumes, the additional wind-powered generation and lower coal generation.

Regulated natural gas operating revenue decreased $121 million for the first nine months of 2012 compared to 2011 due to a lower average per-unit cost of gas sold, resulting in lower cost of sales, and lower volumes from unseasonably warm weather. Regulated natural gas operating income decreased $20 million for the first nine months of 2012 compared to 2011 due to lower volume-related gas margins as a result of unseasonably warm winter and spring temperatures and other usage factors.

Nonregulated and other operating revenue decreased $137 million for the first nine months of 2012 compared to 2011 due to lower electricity and natural gas prices and volumes. Nonregulated and other operating income decreased $10 million for the first nine months of 2012 compared to 2011 due to lower electric margins.

MidAmerican Energy Pipeline Group

Operating revenue increased $1 million for the third quarter of 2012 compared to 2011 due to higher revenue from increased capacity from Kern River's expansion projects of $10 million and higher transportation revenue at Northern Natural Gas of $5 million due to higher Field Area volumes and rates, partially offset by lower sales of gas and condensate liquids totaling $9 million on lower volumes, which are offset in cost of sales. Operating income decreased $11 million for the third quarter of 2012 compared to 2011 as the higher revenue at Kern River and the higher transportation revenue at Northern Natural Gas were more than offset by higher operating expense and depreciation.

Operating revenue increased $1 million for the first nine months of 2012 compared to 2011 as higher revenue from Kern River's expansion projects of $27 million and higher Field Area transportation and storage rates of $5 million at Northern Natural Gas were partially offset by lower sales of gas and condensate liquids of $23 million on lower volumes, which are offset in cost of sales, and contract expirations with capacity sold at lower rates at Kern River. Operating income increased $2 million for the first nine months of 2012 compared to 2011 due to the higher revenue at Kern River and the higher Field Area transportation and storage rates at Northern Natural Gas, partially offset by higher operating expense and depreciation.

Northern Powergrid Holdings

Operating revenue increased $3 million for the third quarter of 2012 compared to 2011 due to higher distribution revenue of $5 million and higher contracting revenue of $3 million, partially offset by the stronger United States dollar totaling $5 million. Distribution revenue increased due to higher tariff rates of $17 million, partially offset by a favorable movement in regulatory provisions in 2011 of $9 million and lower units distributed. Operating income decreased $18 million for the third quarter of 2012 compared to 2011 as the higher distribution revenue was more than offset by higher pension expense of $11 million and higher distribution operating expense of $8 million.

Operating revenue increased $20 million for the first nine months of 2012 compared to 2011 due to higher distribution revenue of $36 million, partially offset by the stronger United States dollar totaling $17 million. Distribution revenue increased due to higher tariff rates of $67 million, partially offset by a favorable movement in regulatory provisions in 2011 of $29 million and lower units distributed. Operating income decreased $25 million for the first nine months of 2012 compared to 2011 as the higher distribution revenue was more than offset by higher pension expense of $33 million, higher distribution operating expense of $18 million and the stronger United States dollar of $9 million.

MidAmerican Renewables

Operating revenue increased $6 million for the third quarter of 2012 compared to 2011 and $5 million for first nine months of 2012 compared to 2011 due to higher variable energy fees earned in 2012 from higher rainfall at the Casecnan project. Operating income was flat for the third quarter and decreased $1 million for first nine months of 2012 compared to 2011 as the higher revenue was offset by higher project evaluation and acquisition costs.

HomeServices

Operating revenue increased $87 million for the third quarter of 2012 compared to 2011 due to an increase from existing businesses totaling $46 million, reflecting a 13.1% increase in closed brokerage units and a 2.7% increase in average home sale prices, and $41 million of revenue from acquired companies. Operating income increased $7 million for the third quarter of 2012 compared to 2011 due to the higher operating revenue, net of commissions, partially offset by higher operating expense at both acquired and existing businesses.

Operating revenue increased $206 million for the first nine months of 2012 compared to 2011 due to an increase from existing businesses totaling $124 million reflecting a 15.4% increase in closed brokerage units and $82 million of revenue from acquired companies. Operating income increased $24 million for the first nine months of 2012 compared to 2011 due to the higher operating revenue, net of commissions, partially offset by higher operating expense of $35 million at both acquired and existing businesses and higher depreciation and amortization at acquired businesses.

MEHC and Other

Operating loss increased $2 million for the third quarter of 2012 compared to 2011 as higher compensation expense was partially offset by the cessation of purchase price pension amortization in 2011.

Operating loss improved by $8 million for the first nine months of 2012 compared to 2011 due to the cessation of purchase price amortization in 2011, partially offset by higher compensation expense.

Consolidated Other Income and Expense Items

Interest Expense

Interest expense is summarized as follows (in millions):

	Third Quarter				**First Nine Months**			
	2012	**2011**	**Change**		**2012**	**2011**	**Change**	
Subsidiary debt	$ 220	$ 213	$ 7	3%	$ 640	$ 638	$ 2	—%
MEHC senior debt and other	78	81	(3)	(4)	244	246	(2)	(1)
MEHC subordinated debt - Berkshire Hathaway	—	3	(3)	(100)	—	12	(12)	(100)
MEHC subordinated debt - other	—	4	(4)	(100)	—	11	(11)	(100)
Total interest expense	$ 298	$ 301	$ (3)	(1)	$ 884	$ 907	$ (23)	(3)

Interest expense decreased $3 million for the third quarter of 2012 compared to 2011 and $23 million for the first nine months of 2012 compared to 2011 due to scheduled maturities and early principal repayments, partially offset by the debt issuances and refinancings at PacifiCorp ($400 million in May 2011, $650 million in January 2012 and $100 million in March 2012), MidAmerican Energy Pipeline Group ($200 million in April 2011 and $250 million in August 2012), Northern Powergrid Holdings (£150 million in July 2012) and MidAmerican Renewables ($850 million in February 2012 and $120 million in August 2012).

Capitalized Interest

Capitalized interest increased $2 million for the third quarter of 2012 compared to 2011 and $6 million for the first nine months of 2012 compared to 2011 due to higher construction in progress balances at Topaz and PacifiCorp, partially offset by lower construction in progress balances at MidAmerican Energy Pipeline Group and MidAmerican Energy.

Other, Net

Other, net increased $18 million for the third quarter of 2012 compared to 2011 and $23 million for the first nine months of 2012 compared to 2011 due to better investment performance and a positive litigation settlement at MidAmerican Energy Pipeline Group.

Income Tax Expense

Income tax expense decreased $21 million for the third quarter of 2012 compared to 2011 and the effective tax rates were 9% for the third quarter of 2012 and 15% for the third quarter of 2011. The decrease in the effective tax rate was due to $25 million of higher income tax benefits related to additional production tax credits at MidAmerican Energy primarily due to wind-powered generation placed in service in late 2011 and the effects of ratemaking.

Income tax expense decreased $67 million for the first nine months of 2012 compared to 2011 and the effective tax rates were 15% for the first nine months of 2012 and 21% for the first nine months of 2011. The decrease in the effective tax rate was due to $45 million of higher income tax benefits related to additional production tax credits at MidAmerican Energy primarily due to wind-powered generation placed in service in late 2011, the effects of ratemaking and the method change for repairs deductions.

In July 2012, the Company recognized $38 million of deferred income tax benefits upon the enactment of a reduction in the United Kingdom corporate income tax rate from 25% to 24% effective April 1, 2012, and a further reduction to 23% effective April 1, 2013. In July 2011, the Company recognized $40 million of deferred income tax benefits upon the enactment of a reduction in the United Kingdom corporate income tax rate from 27% to 26% effective April 1, 2011, and a further reduction to 25% effective April 1, 2012.

Equity Income

Equity income increased $2 million for the third quarter of 2012 compared to 2011 and $19 million for the first nine months of 2012 compared to 2011 due to the acquisition of a 49% interest in Agua Caliente in January 2012 and higher earnings at ETT due to continued investment, partially offset by lower earnings at CE Generation on lower energy rates at the Imperial Valley Projects. Equity income increased for the first nine months of 2012 compared to 2011 due to the reasons stated above, as well as higher earnings at HomeServices' mortgage joint venture due to higher refinancing activity.

Liquidity and Capital Resources

Each of MEHC's direct and indirect subsidiaries is organized as a legal entity separate and apart from MEHC and its other subsidiaries. It should not be assumed that the assets of any subsidiary will be available to satisfy MEHC's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MEHC or affiliates thereof. The long-term debt of subsidiaries may include provisions that allow MEHC's subsidiaries to redeem it in whole or in part at any time. These provisions generally include make-whole premiums. Refer to Note 17 of Notes to Consolidated Financial Statements in Item 8 of the Company's Annual Report on Form 10-K for further discussion regarding the limitation of distributions from MEHC's subsidiaries.

As of September 30, 2012, the Company's total net liquidity was $6.038 billion and the components are as follows (in millions):

	MEHC	PacifiCorp	MidAmerican Funding	Northern Powergrid Holdings	Other	Total
Cash and cash equivalents	$ 603	$ 175	$ 375	$ 164	$ 543	$ 1,860
Credit facilities[1]	1,079	1,230	539	242	95	3,185
Less:						
Short-term debt	(140)	—	—	—	(38)	(178)
Tax-exempt bond support and letters of credit	(32)	(602)	(195)	—	—	(829)
Net credit facilities	907	628	344	242	57	2,178
Net liquidity before Berkshire Equity Commitment	1,510	$ 803	$ 719	$ 406	$ 600	4,038
Berkshire Equity Commitment[2]	2,000					2,000
Total net liquidity	$ 3,510					$ 6,038
Credit facilities:						
Maturity date	2013, 2017	2013, 2017	2013	2017	2012, 2013	
Largest single bank commitment as a % of total credit facilities[3]	13%	14%	28%	33%	53%	

(1) For further discussion regarding the Company's credit facilities, refer to Note 7 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q.

(2) MEHC has an Equity Commitment Agreement with Berkshire Hathaway (the "Berkshire Equity Commitment") pursuant to which Berkshire Hathaway has agreed to purchase up to $2.0 billion of MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The proceeds of any such equity contribution shall only be used for the purpose of (a) paying when due MEHC's debt obligations and (b) funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries. The Berkshire Equity Commitment expires on February 28, 2014.

(3) An inability of financial institutions to honor their commitments could adversely affect the Company's short-term liquidity and ability to meet long-term commitments.

The above table does not include unused credit facilities and letters of credit for investments that are accounted for under the equity method.

Operating Activities

Net cash flows from operating activities for the nine-month periods ended September 30, 2012 and 2011 were $3.682 billion and $2.717 billion, respectively. The increase was primarily due to higher income tax receipts of $667 million from bonus depreciation, investment tax credits related to renewable projects and production tax credits from additional wind generation placed in service; improved operating results; lower interest payments; benefits from changes in collateral posted for derivative contracts; lower domestic employee benefit plan contributions; and other changes in working capital.

Investing Activities

Net cash flows from investing activities for the nine-month periods ended September 30, 2012 and 2011 were $(2.817) billion and $(1.993) billion, respectively. The change was primarily due to higher capital expenditures, the acquisitions of Topaz and Bishop Hill, and equity contributions to Agua Caliente.

Capital Expenditures

Capital expenditures, which exclude amounts for non-cash equity AFUDC and other non-cash items, by reportable segment for the nine-month periods ended September 30 are summarized as follows (in millions):

	2012	2011
Capital expenditures:		
PacifiCorp	$ 1,037	$ 1,069
MidAmerican Funding	445	398
MidAmerican Energy Pipeline Group	112	218
Northern Powergrid Holdings	310	219
MidAmerican Renewables	439	1
Other	6	7
Total capital expenditures	$ 2,349	$ 1,912

The Company's capital expenditures relate primarily to the Utilities and consisted mainly of the following for the nine-month periods ended September 30:

2012:

- Transmission system investments totaling $262 million, including construction costs for PacifiCorp's 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley. A 65-mile segment of the Mona-Oquirrh transmission project will be a single-circuit 500-kV transmission line, while the remaining 35-mile segment will be a double-circuit 345-kV transmission line. The transmission line is expected to be placed in service in 2013.
- Emissions control equipment on existing generating facilities totaling $196 million for installation or upgrade of sulfur dioxide scrubbers, low nitrogen oxide burners and particulate matter control systems.
- The development and construction of PacifiCorp's Lake Side 2 637-MW combined-cycle combustion turbine natural gas-fueled generating facility ("Lake Side 2") totaling $177 million, which is expected to be placed in service in 2014.
- The construction of MidAmerican Energy's 407 MW of wind-powered generating facilities totaling $121 million, excluding $306 million of costs for which payments are due in December 2015. MidAmerican Energy placed in service 214 MW during the third quarter of 2012, and the remaining 193 MW are expected to be placed in service during the fourth quarter of 2012.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling $726 million.

2011:

- The construction of MidAmerican Energy's 594 MW of wind-powered generating facilities totaling $182 million, excluding $376 million of costs for which payments are due in December 2013. The wind-powered generating facilities were placed in service in 2011.
- Emissions control equipment on existing generating facilities totaling $170 million for installation or upgrade of sulfur dioxide scrubbers, low nitrogen oxide burners and particulate matter control systems.
- Transmission system investments totaling $167 million, including permitting and right-of-way costs for PacifiCorp's Mona-Oquirrh substation and transmission project.
- The development and construction of Lake Side 2 totaling $123 million.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling $825 million.

Additionally, capital expenditures for the nine-month period ended September 30, 2012 include costs related to MidAmerican Renewables totaling $439 million related to the Topaz and Bishop Hill Projects. Capital expenditures for the nine-month period ended September 30, 2011 include costs related to Kern River's expansion projects totaling $162 million. The remaining amounts are for ongoing investments in distribution and other infrastructure needed at the other platforms to serve existing and expected demand.

Financing Activities

Net cash flows from financing activities for the nine-month period ended September 30, 2012 was $704 million. Sources of cash totaled $2.199 billion related to proceeds from subsidiary debt. Uses of cash totaled $1.495 billion and consisted mainly of net repayments of short-term debt totaling $715 million, repayments of subsidiary debt totaling $450 million and repayments of MEHC senior and subordinated debt totaling $272 million. For the nine-month period ended September 30, 2012, subsidiary debt issuances included the following:

- In January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 1, 2022 and $300 million of its 4.10% First Mortgage Bonds due February 1, 2042. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes. In March 2012, PacifiCorp issued an additional $100 million of its 2.95% First Mortgage Bonds due February 1, 2022. The net proceeds were used to redeem $84 million of tax-exempt bond obligations prior to scheduled maturity with a weighted average interest rate of 5.7%, to repay short-term debt and for general corporate purposes.
- In February 2012, Topaz issued $850 million of the 5.75% Series A Senior Secured Notes. The principal of the notes amortize beginning September 2015 with a final maturity in September 2039. The net proceeds will be used to fund the costs and expenses related to the development, construction and financing of the Topaz Project. Any unused amounts will be invested or, in certain circumstances, loaned to MEHC. As of June 30, 2012, $421 million was loaned to MEHC.
- In July 2012, Northern Powergrid (Yorkshire) plc issued £150 million of its 4.375% Bonds due July 2032. The net proceeds will be used for general corporate purposes.
- In August 2012, Northern Natural Gas issued $250 million of its 4.10% Senior Bonds due September 2042. The net proceeds were used to partially repay its $300 million, 5.375% Senior Notes due October 2012.
- In August 2012, Bishop Hill issued $120 million of its 5.125% Senior Secured Fixed Rate Notes. The principal of the notes amortize beginning March 2013 with a final maturity in March 2032. The net proceeds will be used to fund the costs and expenses related to the development, construction and financing of the Bishop Hill Project.

In conjunction with the construction of wind-powered generating facilities in 2012, MidAmerican Energy has accrued as construction work-in-progress amounts it is not contractually obligated to pay until December 2015. The amounts ultimately payable are discounted at 1.43% and recognized upon delivery of the equipment as long-term debt. The discount is being amortized as interest expense over the period until payment is due using the effective interest method. As of September 30, 2012, $306 million of such debt from the 2012 wind-powered generation projects, net of associated discount, was outstanding.

Net cash flows from financing activities for the nine-month period ended September 30, 2011 was $(289) million. Uses of cash totaled $1.079 billion and consisted mainly of $601 million for repayments of subsidiary debt, net repayments of short-term debt totaling $320 million and repayments of MEHC subordinated debt totaling $122 million. Sources of cash totaled $790 million related to proceeds from subsidiary debt.

Future Uses of Cash

The Company has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, the issuance of equity and other sources. These sources are expected to provide funds required for current operations, capital expenditures, acquisitions, investments, debt retirements and other capital requirements. The availability and terms under which each subsidiary has access to external financing depends on a variety of factors, including its credit ratings, investors' judgment of risk and conditions in the overall capital market, including the condition of the utility industry and non-recourse project finance market, among other items. Additionally, MEHC has the Berkshire Equity Commitment pursuant to which Berkshire Hathaway has agreed to purchase up to $2.0 billion of MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The Berkshire Equity Commitment expires on February 28, 2014 and may only be used for the purpose of (a) paying when due MEHC's debt obligations and (b) funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request in increments of at least $250 million pursuant to one or more drawings authorized by MEHC's Board of Directors. The funding of any such drawing will be made by means of a cash equity contribution to MEHC in exchange for additional shares of MEHC's common stock.

Capital Expenditures

The Company has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in rules and regulations, including environmental and nuclear; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items, such as pollution-control technologies, replacement generation, nuclear decommissioning, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into MEHC's energy subsidiaries' regulated retail rates.

Forecasted capital expenditures, which exclude amounts for non-cash equity AFUDC and other non-cash items, are approximately $3.3 billion for 2012 and consist mainly of large scale projects at the Utilities and MidAmerican Renewables, including the following:

- $632 million for the Topaz Project, which is a 550-MW solar project in California that will be completed in 22 blocks through 2015, with an aggregate tested capacity of 586 MW. The Topaz Project expects to place 45 MW in service in 2012.
- $344 million for transmission system investments, including $262 million for the Energy Gateway Transmission Expansion Program, which includes construction costs for the Mona-Oquirrh transmission line.
- $264 million for emissions control equipment at the Utilities, which includes equipment to meet air quality and visibility targets, including the reduction of sulfur dioxide, nitrogen oxides and particulate matter emissions. This estimate includes the installation of new or the replacement of existing emissions control equipment at several of the Utilities' coal-fueled generating facilities.
- $230 million for development and construction of Lake Side 2, which is expected to be placed in service in 2014.
- $197 million for 407 MW (nominal ratings) of wind-powered generation at MidAmerican Energy, excluding approximately $400 million of payments deferred until December 2015. MidAmerican Energy placed in service 214 MW during the third quarter of 2012, and the remaining 193 MW are expected to be placed in service during the fourth quarter of 2012.
- $150 million of 81-MW wind-powered generation at the Bishop Hill Project in Illinois that is expected to be placed in service in 2012. In March 2012, MEHC, through a wholly-owned subsidiary, acquired the Bishop Hill Project from Invenergy Wind LLC.

Remaining amounts are for ongoing investments in distribution, generation, mining and other infrastructure needed to serve existing and expected demand.

In September 2012, MidAmerican Renewables, through wholly-owned subsidiaries, signed a definitive agreement, subject to conditions precedent, to acquire all of the equity interests in two project companies that own the 168-MW Alta Wind VII and the 132-MW Alta Wind IX wind-powered generation projects ("Alta Wind Projects"), located in California, which are expected to be placed in service in 2012. Once completed, the Alta Wind Projects will sell all of their generation to Southern California Edison pursuant to the terms of power purchase agreements that extend to 2035. These transactions are expected to close in 2012.

Equity Investments

Agua Caliente, a company owned 51% by NRG Energy, Inc. and 49% by an indirect subsidiary of MEHC, is constructing the 290-MW Agua Caliente Project in Arizona that will be completed in 12 blocks through 2014. Pursuant to an equity funding and contribution agreement, MEHC has committed to provide Agua Caliente with funding for (a) base equity contributions of up to an aggregate amount of $303 million for the construction of the Agua Caliente Project and (b) transmission upgrade costs. MEHC expects to make equity contributions to Agua Caliente during 2012 of $279 million. The equity funding and contribution agreement and the letter of credit commitment decreases as equity is contributed to the Agua Caliente Project. As of September 30, 2012, the balance of the commitment was $169 million.

Contractual Obligations

As of September 30, 2012, there have been no material changes outside the normal course of business in contractual obligations from the information provided in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2011 other than the 2012 debt issuances previously discussed and MidAmerican Energy's redemption of $275 million of its 5.125% senior notes due January 2013. Additionally, refer to the "Capital Expenditures" discussion included in "Liquidity and Capital Resources."

In April 2012, MidAmerican Energy entered into a multi-year coal transportation agreement with BNSF Railway Company, an affiliate of the Company, for long-haul delivery of coal to MidAmerican Energy's generating facilities that are not "captive" to a single railroad. The new contract will provide delivery for the majority of the coal anticipated to be delivered to MidAmerican Energy-operated coal-fueled generating facilities beginning January 1, 2013. While prices for this rail service are significantly higher than those contained in MidAmerican Energy's legacy long-haul rail contract, which expires December 31, 2012, the BNSF Railway Company proposal was the lowest cost and best overall bid.

Regulatory Matters

MEHC's regulated subsidiaries and certain affiliates are subject to comprehensive regulation. The discussion below contains material developments to those matters disclosed in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2011.

PacifiCorp

Utah

In February 2012, PacifiCorp filed a general rate case with the UPSC requesting a rate increase of $172 million, or an average price increase of 10%. In July 2012, PacifiCorp filed rebuttal testimony that reduced the requested increase to $156 million, or an average price increase of 9%. In September 2012, the UPSC approved a multi-year settlement that provides for an annual increase of $100 million, or an average price increase of 6%, effective October 2012, to be followed by an additional annual increase of $54 million, or an average price increase of 3%, effective September 2013. As part of the general rate case settlement, PacifiCorp indicated that it anticipates retiring the 172-MW Carbon coal-fueled generating facility ("Carbon Facility") in early 2015. Refer to "Environmental Laws and Regulations" for a further discussion regarding the Carbon Facility. The settlement authorizes PacifiCorp to recover the remaining depreciation expense and decommissioning costs for the early retirement of the Carbon Facility through 2020, which is the end of the depreciation life previously used for setting rates in Utah.

In March 2012, PacifiCorp filed its first annual energy balancing account with the UPSC requesting: (a) $9 million for recovery of 70% of the net power costs in excess of amounts included in base rates for the period October 1, 2011 through December 31, 2011 and (b) collection of $20 million of excess net power costs representing the first annual installment of the $60 million of excess net power costs approved for recovery in the September 2011 general rate case settlement. Collection of the $20 million installment began in June 2012. The $9 million is under review and a schedule has been established to receive approval from the UPSC by early 2013 on the final amount to be recovered.

In March 2012, PacifiCorp filed with the UPSC to return $4 million to customers through the REC balancing account. The new rates were effective June 2012 on an interim basis until a final order is issued by the UPSC.

Oregon

In February 2012, PacifiCorp made its initial filing for the annual Transition Adjustment Mechanism with the OPUC for an annual increase of $10 million, or an average price increase of 1%, to recover the anticipated net power costs forecasted for calendar year 2013. In July 2012, PacifiCorp filed updated net power costs reducing the requested increase to $3 million, or an average price increase of less than 1%. The filing will be subject to updates through November 2012 and the new rates will be effective January 2013.

In March 2012, PacifiCorp filed a general rate case with the OPUC requesting an annual increase of $41 million, or an average price increase of 3%. In July 2012, a multiparty partial stipulation was filed with the OPUC resolving most components of the general rate case, including PacifiCorp's requests to include in rates the accelerated depreciation and decommissioning costs for the early retirement of the Carbon Facility. The stipulation provides for an annual increase of $24 million, or an average price increase of 2%. If the stipulation is approved by the OPUC, the new rates will be effective January 2013. The issues that were not settled in the stipulation include the prudence of PacifiCorp's investments in environmental controls at its thermal generating facilities, PacifiCorp's request for a power cost adjustment mechanism and PacifiCorp's proposal to add the Mona-Oquirrh transmission line to its rate base through a separate tariff rider when the line goes into service in 2013. A hearing on the issues not resolved through the stipulation was held in October 2012. Post-hearing briefs and oral arguments are scheduled for November 2012 with a decision from the OPUC expected in December 2012.

Wyoming

In December 2011, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $63 million, or an average price increase of 10%, for which the outcome is described below.

In March 2012, PacifiCorp made its first annual Wyoming energy cost adjustment mechanism ("ECAM") filing with the WPSC. The filing requested recovery of $29 million, or an average price increase of 5%, for deferred net power costs for the period December 1, 2010 to December 31, 2011. The new rates were effective May 2012 on an interim basis and were revised in July 2012 in anticipation of the general rate case stipulation described below.

In July 2012, the WPSC approved a stipulation that consolidated and resolved the December 2011 general rate case and the March 2012 ECAM filing. The stipulation resulted in a $50 million general rate increase that will be effective in two stages. The first increase of $32 million, or an average price increase of 5%, was effective in October 2012 and the second increase of $18 million, or an average price increase of 3%, will be effective in October 2013. The stipulation also resulted in a reduction of the ECAM surcharge rate increase from $29 million to $27 million and the increase will be collected over three years. The stipulation authorizes PacifiCorp to recover the remaining depreciation expense and decommissioning costs for the early retirement of the Carbon Facility through 2020, which is the end of the depreciation life previously used for setting rates in Wyoming. In addition, PacifiCorp agreed not to file another general rate case in Wyoming prior to March 2014 with the new rates to be effective no earlier than January 2015. PacifiCorp will continue to file its required annual ECAM filings.

In March 2012, PacifiCorp filed its first annual Wyoming REC and Sulfur Dioxide Revenue Adjustment Mechanism ("RRA") application with the WPSC. The RRA tracks the difference between PacifiCorp's actual revenues from the sale of RECs and sulfur dioxide allowances and the amounts credited to customers in current rates. The filing requested a $1 million reduction in the surcredit to $15 million. The new surcredit became effective in May 2012 on an interim basis. In September 2012, the WPSC approved the RRA on a permanent basis with no change to the previously approved interim rate.

In September 2011, PacifiCorp filed with the WPSC an application for a certificate of public convenience and necessity ("CPCN") for pollution control facilities at Naughton Unit No. 3 in Wyoming. In April 2012, PacifiCorp filed testimony modifying its original CPCN application to reflect its current plan to convert the Naughton Unit No. 3 to a natural gas-fueled unit as a result of PacifiCorp's current estimation that conversion is the least cost alternative for meeting air quality and visibility requirements and is in the best interest of customers. In May 2012, PacifiCorp filed a motion to withdraw the CPCN application, which was approved by the WPSC.

Washington

In May 2010, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $57 million, or an average price increase of 21%. In November 2010, the requested annual increase was reduced to $49 million, or an average price increase of 18%. In March 2011, the WUTC issued an order and clarification letter approving an annual increase of $33 million, or an average price increase of 12%, reduced in the first year by a customer bill credit of $5 million, or 2%, related to the sale of RECs expected during the twelve-month period ended March 31, 2012, as well as requiring PacifiCorp to submit additional information to the WUTC regarding the sales of RECs. The new rates were effective in April 2011. Although both PacifiCorp and the WUTC staff filed petitions for reconsideration of various items in the order, the WUTC denied the petitions for reconsideration. In May 2011, PacifiCorp submitted to the WUTC the additional information required by the March 2011 order regarding PacifiCorp's proceeds from sales of RECs for the period January 1, 2009 forward and a detailed proposal for a tracking mechanism for proceeds of RECs. Intervening parties and WUTC staff proposed that PacifiCorp refund to customers the amount of REC sales in excess of the amount included in base rates since January 1, 2009. Initial and reply briefs from all parties were filed in November 2011. Oral arguments were held before the WUTC in January 2012. In August 2012, the WUTC issued an order requiring PacifiCorp to credit to its customers all proceeds from the sale of RECs attributable to Washington that were booked on or after January 1, 2009, less any amounts already credited to customers. In September 2012, PacifiCorp filed a petition for reconsideration and a petition requesting a stay of the effectiveness of the order. In October 2012, PacifiCorp filed a reply to the intervening parties' and WUTC staff's answers to PacifiCorp's petitions. The WUTC indicated it will act on PacifiCorp's petitions by December 31, 2012. Also in October 2012, PacifiCorp submitted a compliance filing with the WUTC presenting Washington-allocated actual and projected REC sales proceeds from April 2011 through December 2012 and the amount of rate credits provided to customers for the same period.

In July 2011, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $13 million, or an average price increase of 4%, with an effective date no later than June 1, 2012. In February 2012, the parties to the proceeding filed a settlement agreement with the WUTC reflecting an annual increase of $5 million, or an average price increase of 2%. In March 2012, the WUTC approved the settlement agreement with an effective date of June 2012.

Idaho

In February 2012, PacifiCorp filed an ECAM application with the IPUC requesting recovery of $18 million in deferred net power costs with a $3 million increase to the current ECAM surcharge rate. In March 2012, the IPUC approved the new rates with an effective date of April 2012. In April 2012, Monsanto Company filed a motion for reconsideration of the IPUC order. As a result, the IPUC ordered a workshop to discuss certain aspects of PacifiCorp's ECAM application. In June 2012, the parties filed final comments with the IPUC supporting an increase to the current ECAM surcharge rate that will result in recovery of $18 million in deferred net power costs. In July 2012, the IPUC issued a final order approving the agreement reached by the parties.

MidAmerican Energy

On February 21, 2012, MidAmerican Energy filed an application with the IUB for an interim and final increase in Iowa retail electric rates in the form of two adjustment clauses to be added to customers' bills. The requested adjustment clauses and a modification to current revenue sharing provisions are consistent with a November 2011 settlement agreement between MidAmerican Energy and the Iowa Office of Consumer Advocate ("OCA"), in which the parties agreed to support the proposed changes. The adjustment clauses would recover anticipated increases in retail coal and coal transportation costs and environmental control expenditures subject to an aggregate maximum of $39 million, or 3.4%, for 2012 and an additional $37 million for an aggregate maximum of $76 million for 2013, or a 3.2% increase from 2012. The requested modification to the existing revenue sharing provisions provides for MidAmerican Energy to share with its customers 20% of revenue associated with Iowa electric returns on equity between 10% and 10.5%, 50% of revenue associated with Iowa electric returns on equity between 10.5% and 11.75%, 75% of revenue associated with Iowa electric returns on equity between 11.75% and 13.0% and 83.3% of revenue associated with Iowa electric returns on equity above 13.0%. Such shared amounts would reduce MidAmerican Energy's investment in the Walter Scott, Jr. Energy Center Unit 4. Pursuant to the settlement agreement, MidAmerican Energy is not precluded from seeking interim rate relief in 2013. MidAmerican Energy implemented the adjustment clauses on an interim basis in March 2012. On July 27, 2012, MidAmerican Energy, the OCA and a group of large industrial customers jointly filed a new settlement agreement with the IUB that resolved all issues surrounding the Iowa proceeding. This settlement agreement consolidated the two proposed adjustment clauses into a single clause with a fixed revenue increase of $39 million in 2012 and an additional $37 million in 2013. The new settlement agreement contained the same revenue sharing provisions as the November 2011 settlement agreement. On October 8, 2012, the IUB issued an order approving the July 27, 2012 settlement agreement.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, RPS, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state, local and international agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and the Company is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. The Company believes it is in material compliance with all applicable laws and regulations. Refer to "Liquidity and Capital Resources" for discussion of the Company's forecasted environmental-related capital expenditures. The discussion below contains material developments to those matters disclosed in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2011.

Clean Air Standards

National Ambient Air Quality Standards

In June 2012, the EPA released a proposal to strengthen the fine particulate matter National Ambient Air Quality Standards, reducing the standard from 15 micrograms per cubic meter to a range of 12 to 13 micrograms per cubic meter while taking comment on a standard of 11 micrograms per cubic meter. The EPA is also proposing a new, separate fine particulate matter standard of either 28 or 30 deciviews or measure of haze, aimed at improving visibility. The public comment period closed August 31, 2012. The EPA is required to finalize the proposal by December 14, 2012. Until the standards are final and attainment designations made, the Company cannot determine the potential impacts of the standards; however, any impacts are not anticipated to be significant.

Mercury and Air Toxics Standards

The Clean Air Mercury Rule ("CAMR"), issued by the EPA in March 2005, was the United States' first attempt to regulate mercury emissions from coal-fueled generating facilities through the use of a market-based cap-and-trade system. The CAMR, which mandated emissions reductions of approximately 70% by 2018, was overturned by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") in February 2008. In March 2011, the EPA proposed a new rule that would require coal-fueled generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of "Maximum Achievable Control Technology" standards rather than a cap-and-trade system. The final rule, Mercury and Air Toxics Standards ("MATS"), was published in the Federal Register on February 16, 2012, with an effective date of April 16, 2012, and requires that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards by April 16, 2015. Individual sources may be granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. While the final MATS continues to be reviewed by the Company, the Company believes that its emissions reduction projects completed to date or currently permitted or planned for installation, including scrubbers, baghouses and electrostatic precipitators, are consistent with the EPA's MATS and will support the Company's ability to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants. The Company will be required to take additional actions to reduce mercury emissions through the installation of controls or use of sorbent injection at certain of its coal-fueled generating facilities and otherwise comply with the final rule's standards. The Company is evaluating whether or not to close certain units. As a result of recent testing and evaluation, PacifiCorp currently anticipates that retiring the Carbon Facility in early 2015 will be the least-cost alternative to comply with the MATS and other environmental regulations. PacifiCorp continues to assess compliance alternatives and potential transmission system impacts that could otherwise impact PacifiCorp's ultimate decision with respect to the Carbon Facility, including timing of retirement and decommissioning. Incremental costs to install and maintain emissions control equipment at the Company's coal-fueled generating facilities and any requirement to shut down what have traditionally been low cost coal-fueled generating facilities will likely increase the cost of providing service to customers. In addition, numerous lawsuits are pending against the MATS in the D.C. Circuit, which may have an impact on the Company's compliance obligations and the timing of those obligations.

Cross-State Air Pollution Rule

In August 2012, the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") vacated the Cross-State Air Pollution Rule ("CSAPR") in a 2-1 decision after it determined that the CSAPR exceeded the EPA's statutory authority. The CSAPR was promulgated by the EPA as the replacement rule for the Clean Air Interstate Rule after it was struck down by the D.C. Circuit in July 2008, and was designed to reduce interstate transport of emissions of ozone and fine particulate matter from downwind states in the eastern United States. In a petition filed in October 2012, the EPA sought a full review of the CSAPR ruling by the entire D.C. Circuit. Until such time as the challenges to the CSAPR are resolved or the EPA proposes and adopts a new rule, the Company will continue to operate in compliance with the Clean Air Interstate Rule, which has remained in effect since the D.C. Circuit stayed the CSAPR in December 2011.

Regional Haze

In May 2012, the EPA published in the Federal Register a proposal to partially approve and partially disapprove the Utah regional haze state implementation plan ("SIP"). The EPA's partial approval of the sulfur dioxide portion of the SIP is based on a sulfur dioxide milestone and backstop trading program to reduce emissions. The partial disapproval is based on the EPA's assertion that the Utah Department of Environmental Quality failed to conduct the appropriate five-factor best available retrofit technology analysis for nitrogen oxides and particulate matter. The EPA did not propose to issue a Federal Implementation Plan ("FIP"), but acknowledged the state's ongoing efforts to conduct the required analysis. The public comment period closed on the EPA's proposed action in July 2012 and the Company expects a final decision in the fourth quarter of 2012.

In May 2012, the EPA published in the Federal Register a proposal to approve the Wyoming regional haze SIP for sulfur dioxide. The Wyoming SIP utilizes the same trading program utilized by Utah. The EPA's public comment period closed in July 2012. In addition, the EPA published in the Federal Register a proposal to partially approve and partially disapprove the Wyoming regional haze SIP for nitrogen oxides and particulate matter and issue a FIP for those portions proposed to be disapproved. The EPA action proposed to accelerate the installation of selective catalytic reduction equipment at PacifiCorp's Jim Bridger Units 1 and 2 to 2017 from 2021 and 2022, but agreed to accept comment on maintaining the original schedule as the state proposed. In addition, the EPA proposed to reject the SIP for the Wyodak facility and Dave Johnston Unit 3 and require the installation of selective non-catalytic reduction equipment within five years, as well as requiring the installation of low-nitrogen oxides burners and overfire air systems at Dave Johnston Units 1 and 2. The EPA held public hearings on its proposed disapproval on June 26 and 28, 2012, and the written comment period closed August 3, 2012. Until the EPA takes final action on the SIP or FIP and the appropriate appeal period passes, the Company cannot fully determine the impacts of the EPA's proposal.

In July 2012, the EPA published in the Federal Register a proposal to partially approve and partially disapprove the Arizona regional haze SIP addressing, among others, the Cholla generating facility. PacifiCorp owns 100% of Cholla Unit 4. The Arizona SIP provided for low-nitrogen oxides burners, while the proposed FIP would require installation of selective catalytic reduction equipment within five years after final action. The written comment period closed September 18, 2012. On October 12, 2012, the State of Arizona provided notice of its intent to file a citizen suit under Section 304 of the Clean Air Act for failing to timely act on the SIP for regional haze and for bifurcating its decision on Arizona's state-wide plan into two parts. Until the EPA takes final action on the SIP or FIP or otherwise addresses the potential citizens' suit, the Company cannot fully determine the impacts of the EPA's proposal.

Climate Change

GHG New Source Performance Standards

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emissions reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. The EPA entered into a settlement agreement with a number of parties, including certain state governments and environmental groups, in December 2010 to promulgate emissions standards covering GHG. In April 2012, the EPA proposed new source performance standards for new fossil-fueled generating facilities that would limit emissions of carbon dioxide to 1,000 pounds per megawatt hour. The proposal exempts simple cycle combustion turbines from meeting the GHG standards. The public comment period closed in June 2012. The EPA indicated in the proposal that it does not have sufficient information to establish GHG new source performance standards for modified or reconstructed units and has not established a schedule for when these units, or other existing sources, will be regulated. Any new fossil-fueled generating facilities constructed by the Company will be required to meet the final GHG new source performance standards, which, if finalized as proposed, will preclude the construction of any coal-fueled generating facilities that do not have carbon capture and sequestration. Additionally, as proposed, it may be difficult even for combined cycle combustion turbines to meet the carbon dioxide emission standard under certain operating scenarios such as simple cycle or low-load operations on a sustained basis. Until any standards for existing, modified or reconstructed units are proposed and finalized, the impact on the Company's existing facilities cannot be determined.

GHG Litigation

In 2007, the United States District Court for the Southern District of Mississippi ("Southern District of Mississippi") dismissed the case of *Ned Comer, et al. v. Murphy Oil USA, et al.* ("Comer I"). Plaintiffs brought the putative class action lawsuit based on claims that the defendants' GHG emissions contributed to global warming that resulted in a rise in sea level and added to the ferocity of Hurricane Katrina, which caused damage to the plaintiffs' property. Plaintiffs petitioned for a rehearing before the full court of the United States Court for Appeals for the Fifth Circuit ("Fifth Circuit") in March 2010, but in May 2010, the Fifth Circuit dismissed the appeal for failure to have a quorum. The dismissal resulted in the Southern District of Mississippi's decision, holding that property owners did not have standing to sue for climate change and that climate change was a political question for the United States Congress, standing as good law. However, in May 2011, the Comer case was refiled ("Comer II") in the Southern District of Mississippi. In response to the defendants' motions to dismiss in Comer II, the Southern District of Mississippi, in March 2012, granted the motions, dismissing the suit with prejudice. Plaintiffs filed an appeal with the Fifth Circuit in April 2012. The Company was not a party in Comer I and is not a party in Comer II.

In September 2012, the United States Court of Appeals for the Ninth Circuit (“Ninth Circuit”) issued its opinion in *Native Village of Kivalina v. ExxonMobil* ("Kivalina"), affirming the United States District Court for the Northern District of California's dismissal of the plaintiffs' complaint. MEHC was a named defendant in the Kivalina case. The Ninth Circuit held that the Clean Air Act displaced the plaintiffs' federal common law claims. On October 4, 2012, the plaintiffs filed a petition for a full rehearing by the Ninth Circuit.

Collateral and Contingent Features

Debt of MEHC and debt and preferred securities of certain of its subsidiaries are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of the rated company's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

MEHC and its subsidiaries have no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. The Company's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability but, under certain instances, must maintain sufficient covenant tests if ratings drop below a certain level. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain provisions that require certain of MEHC's subsidiaries, principally the Utilities, to maintain specific credit ratings on their unsecured debt from one or more of the three recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in the subsidiary's creditworthiness. These rights can vary by contract and by counterparty. As of September 30, 2012, these subsidiary's credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of September 30, 2012, the Company would have been required to post $537 million of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for a discussion of the Company's collateral requirements specific to the Company's derivative contracts.

In accordance with MEHC's equity commitment agreement related to Topaz, if MEHC does not maintain at least an investment grade credit rating from at least two of the three credit ratings agencies, MEHC's obligations under the equity commitment agreement would be supported by cash collateral or a letter of credit issued by a financial institution that meets certain minimum criteria specified in the financing documents. Upon reaching the final commercial operation date of the Topaz Project, MEHC will have no further obligation to make any equity contribution and any unused equity contribution obligations will be canceled.

In July 2010, the President signed into law the Dodd-Frank Reform Act. The Dodd-Frank Reform Act reshapes financial regulation in the United States by creating new regulators, regulating new markets and firms, and providing new enforcement powers to regulators. Virtually all major areas of the Dodd-Frank Reform Act are subject to extensive rulemaking proceedings being conducted both jointly and independently by multiple regulatory agencies, some of which have been completed and others that are expected to be finalized in late 2012 and 2013.

The Company is a party to derivative contracts, including over-the-counter derivative contracts. The Dodd-Frank Reform Act provides for extensive new regulation of over-the-counter derivative contracts and certain market participants, including imposition of mandatory clearing, exchange trading, capital, margin, reporting, recordkeeping, and business conduct requirements primarily for "swap dealers" and "major swap participants." The Dodd-Frank Reform Act provides certain exemptions from these requirements for commercial end-users when using derivatives to hedge or mitigate commercial risk of their businesses. While the Company generally does not enter into over-the-counter derivative contracts for purposes unrelated to hedging or mitigating commercial risk and does not anticipate that it will be considered a swap dealer or major swap participant, the outcome of remaining rulemaking proceedings cannot be predicted and, therefore, the impact of the Dodd-Frank Reform Act on the Company's consolidated financial results cannot be determined at this time.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting the Company, refer to Note 2 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. Estimates are used for, but not limited to, the accounting for the effects of certain types of regulation, derivatives, impairment of long-lived assets and goodwill, pension and other postretirement benefits, income taxes and revenue recognition - unbilled revenue. For additional discussion of the Company's critical accounting estimates, see Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2011. There have been no significant changes in the Company's assumptions regarding critical accounting estimates since December 31, 2011.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For quantitative and qualitative disclosures about market risk affecting the Company, see Item 7A of the Company's Annual Report on Form 10-K for the year ended December 31, 2011. The Company's exposure to market risk and its management of such risk has not changed materially since December 31, 2011. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for disclosure of the Company's derivative positions as of September 30, 2012.

Item 4. Controls and Procedures

At the end of the period covered by this Quarterly Report on Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon that evaluation, the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that the Company's disclosure controls and procedures were effective to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission's rules and forms, and is accumulated and communicated to management, including the Company's Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. There has been no change in the Company's internal control over financial reporting during the quarter ended September 30, 2012 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II

Item 1. Legal Proceedings

For a description of certain legal proceedings affecting the Company, refer to Note 10 of Notes to Consolidated Financial Statements included in Part I, Item 1 of this Form 10-Q.

Item 1A. Risk Factors

There has been no material change to the Company's risk factors from those disclosed in Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2011.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Not applicable.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Information regarding the Company's mine safety violations and other legal matters disclosed in accordance with Section 1503 (a) of the Dodd-Frank Reform Act is included in Exhibit 95 to this Form 10-Q.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

The exhibits listed on the accompanying Exhibit Index are filed as part of this Quarterly Report.

SIGNATURES

Pursuant to the requirements 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.

MIDAMERICAN ENERGY HOLDINGS COMPANY
(Registrant)

Date: November 2, 2012

/s/ Patrick J. Goodman
Patrick J. Goodman
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

EXHIBIT INDEX

Exhibit No.	Description
4.1	Fiscal Agency Agreement, dated August 27, 2012, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the $250,000,000 in principal amount of the 4.10% Senior Bonds due 2042.
10.1	£150,000,000 Facility Agreement, dated August 20, 2012, among Northern Powergrid Holdings Company, as Borrower, and Abbey National Treasury Services plc, Lloyds TSB Bank plc and The Royal Bank of Scotland plc, as Original Lenders.
15	Awareness Letter of Independent Registered Public Accounting Firm.
31.1	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.
101	The following financial information from MidAmerican Energy Holdings Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, is formatted in XBRL (eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Equity, (v) the Consolidated Statements of Cash Flows, and (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail.

EXHIBIT 15

AWARENESS LETTER OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

MidAmerican Energy Holdings Company
Des Moines, Iowa

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited consolidated interim financial information of MidAmerican Energy Holdings Company and subsidiaries for the periods ended September 30, 2012 and 2011, as indicated in our report dated November 2, 2012; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, is incorporated by reference in Registration Statement No. 333-147957 on Form S-8.

We also are aware that the aforementioned report, pursuant to Rule 436(c) under the Securities Act of 1933, is not considered a part of the Registration Statement prepared or certified by an accountant or a report prepared or certified by an accountant within the meaning of Sections 7 and 11 of that Act.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
November 2, 2012

EXHIBIT 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Gregory E. Abel, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of MidAmerican Energy Holdings Company;
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: November 2, 2012

/s/ Gregory E. Abel
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Patrick J. Goodman, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of MidAmerican Energy Holdings Company;
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: November 2, 2012

/s/ Patrick J. Goodman
Patrick J. Goodman
Executive Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Gregory E. Abel, Chairman, President and Chief Executive Officer of MidAmerican Energy Holdings Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the quarterly period ended September 30, 2012 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: November 2, 2012

/s/ Gregory E. Abel
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

CERTIFICATION PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Patrick J. Goodman, Executive Vice President and Chief Financial Officer of MidAmerican Energy Holdings Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the quarterly period ended September 30, 2012 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: November 2, 2012

/s/ Patrick J. Goodman
Patrick J. Goodman
Executive Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 95

MINE SAFETY VIOLATIONS AND OTHER LEGAL MATTER DISCLOSURES PURSUANT TO SECTION 1503(a) OF THE DODD-FRANK WALL STREET REFORM AND CONSUMER PROTECTION ACT

PacifiCorp and its subsidiaries operate certain coal mines and coal processing facilities (collectively, the "mining facilities") that are regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Safety Act"). MSHA inspects PacifiCorp's mining facilities on a regular basis. The total number of reportable Mine Safety Act citations, orders, assessments and legal actions for the three-month period ended September 30, 2012 are summarized in the table below and are subject to contest and appeal. The severity and assessment of penalties may be reduced or, in some cases, dismissed through the contest and appeal process. Amounts are reported regardless of whether PacifiCorp has challenged or appealed the matter. Coal reserves that are not yet mined and mines that are closed or idled are not included in the information below as no reportable events occurred at those locations during the three-month period ended September 30, 2012. There were no mining-related fatalities during the three-month period ended September 30, 2012. PacifiCorp has not received any notice of a pattern, or notice of the potential to have a pattern, of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards under Section 104(e) of the Mine Safety Act during the three-month period ended September 30, 2012.

	Mine Safety Act						Legal Actions		
Mining Facilities	**Section 104 Significant and Substantial Citations[1]**	**Section 104(b) Orders[2]**	**Section 104(d) Citations/ Orders[3]**	**Section 110(b)(2) Violations[4]**	**Section 107(a) Imminent Danger Orders[5]**	**Total Value of Proposed MSHA Assessments (in thousands)**	**Pending as of Last Day of Period[6]**	**Instituted During Period**	**Resolved During Period**
Deer Creek	2	—	—	—	—	$ 10	5	3	6
Bridger (surface)	2	—	—	—	—	1	3	1	—
Bridger (underground)	20	—	3	—	—	65	25	6	1
Cottonwood Preparatory Plant	—	—	—	—	—	—	—	—	—
Wyodak Coal Crushing Facility	—	—	—	—	—	—	—	—	—

(1) Citations for alleged violations of mandatory health and safety standards that could significantly or substantially contribute to the cause and effect of a safety or health hazard under Section 104 of the Mine Safety Act.

(2) For alleged failure to totally abate the subject matter of a Mine Safety Act Section 104(a) citation within the period specified in the citation.

(3) For an alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mandatory health or safety standard.

(4) For alleged flagrant violations (i.e., reckless or repeated failure to make reasonable efforts to eliminate a known violation of a mandatory health or safety standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury).

(5) For the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated.

(6) Amounts include contests of 28 proposed penalties under Subpart C and contests of five citations or orders under Subpart B of the Federal Mine Safety and Health Review Commission's procedural rules. The pending legal actions are not exclusive to citations, notices, orders and penalties assessed by MSHA during the reporting period.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2011

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	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
001-14881	**MIDAMERICAN ENERGY HOLDINGS COMPANY** **(An Iowa Corporation)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**94-2213782**

Securities registered pursuant to Section 12(b) of the Act: None
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 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 is not contained herein, and will not be contained, to the best of the 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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ 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 ☒

All of the shares of common equity of MidAmerican Energy Holdings Company are privately held by a limited group of investors. As of January 31, 2012, 74,609,001 shares of common stock were outstanding.

TABLE OF CONTENTS

PART I

PART II

PART III

PART IV

Definition of Abbreviations and Industry Terms

When used in Part I, Items 1 through 4, and Part II, Items 5 through 7A and Items 9, 9A and 9B, the following terms have the definitions indicated.

MidAmerican Energy Holdings Company and Related Entities

MEHC	MidAmerican Energy Holdings Company
Company	MidAmerican Energy Holdings Company and its subsidiaries
PacifiCorp	PacifiCorp and its subsidiaries
MidAmerican Funding	MidAmerican Funding, LLC
MidAmerican Energy	MidAmerican Energy Company
Northern Natural Gas	Northern Natural Gas Company
Kern River	Kern River Gas Transmission Company
Northern Powergrid Holdings	Northern Powergrid Holdings Company
MidAmerican Energy Pipeline Group	Consists of Northern Natural Gas and Kern River
MidAmerican Renewables	Consists of MidAmerican Renewables, LLC and CalEnergy Philippines
CE Casecnan	CE Casecnan Water and Energy Company, Inc.
HomeServices	HomeServices of America, Inc. and its subsidiaries
ETT	Electric Transmission Texas, LLC
Domestic Regulated Businesses	PacifiCorp, MidAmerican Energy Company, Northern Natural Gas Company and Kern River Gas Transmission Company
Utilities	PacifiCorp and MidAmerican Energy Company
Pipeline Companies	Northern Natural Gas Company and Kern River Gas Transmission Company
Distribution Companies	Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc
Berkshire Hathaway	Berkshire Hathaway Inc. and its subsidiaries
Topaz	Topaz Solar Farms LLC
Topaz Project	Topaz Solar Farms LLC's 550-megawatt solar project
Agua Caliente	Agua Caliente Solar, LLC
Agua Caliente Project	Agua Caliente Solar, LLC's 290-megawatt solar project

Certain Industry Terms

AFUDC	Allowance for Funds Used During Construction
Bcf	Billion cubic feet
CAIR	Clean Air Interstate Rule
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
Dodd-Frank Reform Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dth	Decatherms
DSM	Demand-side Management
EBA	Energy Balancing Account
ECAM	Energy Cost Adjustment Mechanism
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GEMA	Gas and Electricity Markets Authority
GHG	Greenhouse Gases
GHG Reporting	Greenhouse Gases Reporting
GWh	Gigawatt Hours

Definition of Abbreviations and Industry Terms (continued)

Certain Industry Terms (continued)

IPUC	Idaho Public Utilities Commission
IUB	Iowa Utilities Board
kV	Kilovolt
LNG	Liquefied Natural Gas
LDC	Local Distribution Company
MATS	Mercury and Air Toxics Standards
MISO	Midwest Independent Transmission System Operator, Inc.
MW	Megawatts
MWh	Megawatt Hours
NRC	Nuclear Regulatory Commission
OPUC	Oregon Public Utility Commission
PCAM	Power Cost Adjustment Mechanism
PTAM	Post Test-year Adjustment Mechanism
RAC	Renewable Adjustment Clause
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
SIP	State Implementation Plan
SEC	United States Securities and Exchange Commission
TAM	Transition Adjustment Mechanism
UPSC	Utah Public Service Commission
WECC	Western Electricity Coordinating Council
WPSC	Wyoming Public Service Commission
WUTC	Washington Utilities and Transportation Commission

Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can typically be identified by the use of forward-looking words, such as "will," "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon the Company's current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside the control of the Company and could cause actual results to differ materially from those expressed or implied by such forward-looking statements. These factors include, among others:

- general economic, political and business conditions, as well as changes in laws and regulations affecting the Company's operations or related industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce generating facility output, accelerate generating facility retirements or delay generating facility construction or acquisition;
- the outcome of general rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies and the Company's ability to recover costs in a timely manner;
- changes in economic, industry, competition or weather conditions, as well as demographic trends, that could affect customer growth and usage, electricity and natural gas supply or the Company's ability to obtain long-term contracts with customers and suppliers;
- a high degree of variance between actual and forecasted load that could impact the Company's hedging strategy and the cost of balancing its generation resources and wholesale activities with its retail load obligations;
- performance and availability of the Company's generating facilities, including the impacts of outages and repairs, transmission constraints, weather and operating conditions;
- changes in prices, availability and demand for both purchases and sales of wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generating capacity and energy costs;
- the financial condition and creditworthiness of the Company's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate, the base interest rate for MEHC's and its subsidiaries' credit facilities;
- changes in MEHC's and its subsidiaries' credit ratings;
- risks relating to nuclear generation;
- the impact of derivative contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in commodity prices, interest rates and other conditions that affect the fair value of derivative contracts;
- the impact of inflation on costs and our ability to recover such costs in regulated rates;
- increases in employee healthcare costs;
- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements;
- changes in the residential real estate brokerage and mortgage industries and regulations that could affect brokerage and mortgage transaction levels;
- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future generating facilities and infrastructure additions;
- the availability and price of natural gas in applicable geographic regions;
- the impact of new accounting guidance or changes in current accounting estimates and assumptions on the Company's consolidated financial results;
- the Company's ability to successfully integrate future acquired operations into its business;

- other risks or unforeseen events, including the effects of storms, floods, litigation, wars, terrorism, embargoes and other catastrophic events; and
- other business or investment considerations that may be disclosed from time to time in MEHC's filings with the SEC or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Company are described in Item 1A and other discussions contained in this Form 10-K. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing factors should not be construed as exclusive.

PART I

Item 1. Business

General

MEHC is a holding company that owns subsidiaries principally engaged in energy businesses and is a consolidated subsidiary of Berkshire Hathaway. The balance of MEHC's common stock is owned by Mr. Walter Scott, Jr., a member of MEHC's Board of Directors (along with family members and related entities), and Mr. Gregory E. Abel, MEHC's Chairman, President and Chief Executive Officer. As of January 31, 2012, Berkshire Hathaway, Mr. Scott (along with family members and related entities) and Mr. Abel owned 89.8%, 9.4% and 0.8%, respectively, of MEHC's voting common stock.

MEHC and Berkshire Hathaway entered into an Equity Commitment Agreement (the "Berkshire Equity Commitment") pursuant to which Berkshire Hathaway has agreed to purchase up to $2.0 billion of MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The proceeds of any such equity contribution shall only be used for the purpose of (a) paying when due MEHC's debt obligations and (b) funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request in increments of at least $250 million pursuant to one or more drawings authorized by MEHC's Board of Directors. The funding of each drawing will be made by means of a cash equity contribution to MEHC in exchange for additional shares of MEHC's common stock. The Berkshire Equity Commitment expires on February 28, 2014.

The Company's operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding (which primarily consists of MidAmerican Energy), Northern Natural Gas, Kern River, Northern Powergrid Holdings (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), CalEnergy Philippines (which owns a majority interest in the Casecnan project in the Philippines), MidAmerican Renewables, LLC (formerly CalEnergy U.S., which owns interests in independent power projects in the United States), and HomeServices. Through these platforms, the Company owns and operates an electric utility company in the Western United States, an electric and natural gas utility company in the Midwestern United States, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of independent power projects and the second largest residential real estate brokerage firm in the United States.

MEHC's energy subsidiaries generate, transmit, store, distribute and supply energy. Approximately 93% of the Company's operating income during 2011 was generated from rate-regulated businesses. As of December 31, 2011, MEHC's electric and natural gas utility subsidiaries served 6.3 million electricity customers and end-users and 0.7 million natural gas customers. MEHC's natural gas pipeline subsidiaries operate interstate natural gas transmission systems that transported approximately 8% of the total natural gas consumed in the United States during 2011. These pipeline subsidiaries have approximately 16,600 miles of pipeline and a design capacity of approximately 7.7 Bcf of natural gas per day. As of December 31, 2011, the Company owned approximately 19,700 MW of generation in operation and under construction, including approximately 18,700 MW of generation that is part of the regulated asset base of its electric utility businesses and approximately 1,000 MW of generation in independent power projects.

Refer to Note 22 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional reportable segment information regarding MEHC's platforms. Effective December 31, 2011, the Company changed its reportable segments. Northern Natural Gas and Kern River have been aggregated in the reportable segment called MidAmerican Energy Pipeline Group and CalEnergy Philippines and MidAmerican Renewables, LLC have been aggregated in the reportable segment called MidAmerican Renewables.

MEHC's principal executive offices are located at 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580 and its telephone number is (515) 242-4300. MEHC was initially incorporated in 1971 as California Energy Company, Inc. under the laws of the state of Delaware and through a merger transaction in 1999 was reincorporated in Iowa under the name MidAmerican Energy Holdings Company.

PacifiCorp

General

PacifiCorp, an indirect wholly owned subsidiary of MEHC, is a United States regulated electric utility company headquartered in Oregon that serves 1.7 million retail electric customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. PacifiCorp's combined service territory covers approximately 136,000 square miles and includes diverse regional economies ranging from rural, agricultural and mining areas to urban, manufacturing and government service centers. No single segment of the economy dominates the service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, consisting of Utah, Wyoming and southeastern Idaho, the principal industries are manufacturing, mining or extraction of natural resources, agriculture, technology and recreation. In the western portion of the service territory, consisting of Oregon, southern Washington and northern California, the principal industries are agriculture, manufacturing, forest products, food processing, technology and primary metals. In addition to retail sales, PacifiCorp sells electricity to other utilities, energy marketing companies, financial institutions and other market participants on a wholesale basis.

PacifiCorp's operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The average term of the franchise agreements is approximately 30 years, although their terms range from five years to indefinite. Several of these franchise agreements allow the municipality the right to seek amendment to the franchise agreement at a specified time during the term. PacifiCorp generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electric service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow PacifiCorp an opportunity to recover its costs of providing services and to earn a reasonable return on its investment.

Regulated Electric Operations

Customers

The GWh and percentages of electricity sold to retail customers by jurisdiction for the years ended December 31 were as follows:

	2011		2010		2009	
Utah	23,245	43%	22,477	42%	22,098	42%
Oregon	13,014	24	12,717	24	13,422	25
Wyoming	9,793	18	9,680	18	9,202	17
Washington	4,006	7	3,985	8	4,184	8
Idaho	3,440	6	3,326	6	2,956	6
California	809	2	831	2	848	2
	54,307	100%	53,016	100%	52,710	100%

Electricity sold to retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2011		2010		2009	
GWh sold:						
Residential	16,046	25%	15,795	24%	15,999	24%
Commercial	16,489	25	15,969	25	16,194	25
Industrial	21,229	32	20,680	32	19,934	31
Other	543	1	572	1	583	1
Total retail	54,307	83	53,016	82	52,710	81
Wholesale	10,767	17	11,415	18	12,349	19
Total GWh sold	65,074	100%	64,431	100%	65,059	100%
Average number of retail customers (in thousands):						
Residential	1,483	85%	1,475	85%	1,467	85%
Commercial	221	13	220	13	214	13
Industrial	34	2	34	2	34	2
Other	4	—	4	—	4	—
Total	1,742	100%	1,733	100%	1,719	100%

In addition to the variations in weather from year to year, fluctuations in economic conditions within PacifiCorp's service territory and elsewhere impact customer usage, particularly for industrial and wholesale customers. Beginning in the fourth quarter of 2008 and continuing into 2009, certain customer usage levels declined due to the effects of the economic conditions in the United States. The declining usage trend reversed during 2010 in the eastern side of PacifiCorp's service territory although partially offset by unfavorable weather conditions. The declining usage trend continued during 2010 in the western side of PacifiCorp's service territory. During 2011, PacifiCorp's customer usage levels increased in the eastern service territory primarily due to improving economic conditions and increased in the western service territory mainly due to weather impacts.

The annual hourly peak customer demand, which represents the highest demand on a given day and at a given hour, is typically highest in the summer across PacifiCorp's service territory when air conditioning and irrigation systems are heavily used. The service territory also has a winter peak, which is primarily due to heating requirements in the western portion of PacifiCorp's service territory. During 2011, PacifiCorp's peak demand was 9,431 MW in the summer and 8,786 MW in the winter.

Generating Facilities and Fuel Supply

PacifiCorp has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding PacifiCorp's owned generating facilities as of December 31, 2011:

Generating Facility	**Location**	**Energy Source**	**Installed**	**Facility Net Capacity (MW)(1)**	**Net Owned Capacity (MW)(1)**
COAL:					
Jim Bridger	Rock Springs, WY	Coal	1974-1979	2,118	1,412
Hunter Nos. 1, 2 and 3	Castle Dale, UT	Coal	1978-1983	1,352	1,147
Huntington	Huntington, UT	Coal	1974-1977	909	909
Dave Johnston	Glenrock, WY	Coal	1959-1972	762	762
Naughton	Kemmerer, WY	Coal	1963-1971	700	700
Cholla No. 4	Joseph City, AZ	Coal	1981	395	395
Wyodak	Gillette, WY	Coal	1978	335	268
Carbon	Castle Gate, UT	Coal	1954-1957	172	172
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	863	166
Colstrip Nos. 3 and 4	Colstrip, MT	Coal	1984-1986	1,480	148
Hayden Nos. 1 and 2	Hayden, CO	Coal	1965-1976	446	78
				9,532	6,157
NATURAL GAS:					
Lake Side	Vineyard, UT	Natural gas/steam	2007	558	558
Currant Creek	Mona, UT	Natural gas/steam	2005-2006	550	550
Chehalis	Chehalis, WA	Natural gas/steam	2003	520	520
Hermiston	Hermiston, OR	Natural gas/steam	1996	474	237
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955	231	231
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	120	120
				2,453	2,216
HYDROELECTRIC:					
Lewis River System	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System	OR	Hydroelectric	1950-1956	204	204
Klamath River System	CA, OR	Hydroelectric	1903-1962	170	170
Bear River System	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System	OR	Hydroelectric	1912-1957	52	52
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	36	36
				1,145	1,145
WIND:					
Marengo	Dayton, WA	Wind	2007-2008	210	210
Glenrock	Glenrock, WY	Wind	2008-2009	138	138
Seven Mile Hill	Medicine Bow, WY	Wind	2008	119	119
Dunlap Ranch	Medicine Bow, WY	Wind	2010	111	111
Leaning Juniper	Arlington, OR	Wind	2006	101	101
High Plains	McFadden, WY	Wind	2009	99	99
Rolling Hills	Glenrock, WY	Wind	2009	99	99
Goodnoe Hills	Goldendale, WA	Wind	2008	94	94
Foote Creek	Arlington, WY	Wind	1999	41	32
McFadden Ridge	McFadden, WY	Wind	2009	28	28
				1,040	1,031
OTHER:					
Blundell	Milford, UT	Geothermal	1984, 2007	34	34
Camas Co-Gen	Camas, WA	Black liquor	1996	14	14
				48	48
Total Available Generating Capacity				14,218	10,597
PROJECTS UNDER CONSTRUCTION(2):					
Lake Side 2	Vineyard, UT	Natural gas/steam		637	637
				14,855	11,234

(1) Facility Net Capacity represents (except for wind-powered generating facilities, which are nominal ratings) the total capability of a generating unit as demonstrated by actual operating or test experience less power generated and used for auxiliaries and other station uses, and is determined using average annual temperatures. A wind turbine generator's nominal rating is the manufacturer's contractually specified capability (in MW) under specified conditions. Net Owned Capacity indicates PacifiCorp's ownership of Facility Net Capacity.

(2) Facility Net Capacity and Net Owned Capacity for projects under construction each represent the estimated ratings.

The following table shows the percentages of PacifiCorp's total energy supplied by energy source for the years ended December 31:

	2011	2010	2009
Coal	59%	62%	63%
Natural gas	9	12	12
Hydroelectric	7	5	5
Other[1]	5	5	4
Total energy generated	80	84	84
Energy purchased - short-term contracts and other	12	8	10
Energy purchased - long-term contracts	8	8	6
	100%	100%	100%

(1) All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with RPS or other regulatory requirements, or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

PacifiCorp is required to have resources available to continuously meet its customer needs. The percentage of PacifiCorp's energy supplied by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages; fuel commodity prices; fuel transportation costs; weather; environmental considerations; transmission constraints; and wholesale market prices of electricity. PacifiCorp evaluates these factors continuously in order to facilitate economical dispatch of its generating facilities. When factors for one energy source are less favorable, PacifiCorp must place more reliance on other energy sources. For example, PacifiCorp can generate more electricity using its low cost hydroelectric and wind-powered generating facilities when factors associated with these facilities are favorable. When factors associated with hydroelectric and wind resources are less favorable, PacifiCorp increases its reliance on coal- and natural gas-fueled generation or purchased electricity. In addition to meeting its customers' energy needs, PacifiCorp is required to maintain operating reserves on its system to mitigate unplanned outages or other disruption in supply, and to meet intra-hour changes in load and resource balance. This operating reserve requirement is dispersed across PacifiCorp's generation portfolio on a least-cost basis based on the operating characteristics of the portfolio. Operating reserves may be held on hydroelectric, coal-fueled or natural gas-fueled resources. PacifiCorp manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives, including forwards, futures, options, swaps and other agreements. Refer to Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

PacifiCorp has interests in coal mines that support its coal-fueled generating facilities and operates the Deer Creek, Bridger surface and Bridger underground coal mines. These mines supplied 28%, 29% and 31% of PacifiCorp's total coal requirements during the years ended December 31, 2011, 2010 and 2009, respectively. The remaining coal requirements are acquired through long- and short-term third-party contracts. PacifiCorp also operates the Cottonwood Preparatory Plant and Wyodak Coal Crushing Facility. PacifiCorp's mines are located adjacent to certain of its coal-fueled generating facilities, which significantly reduces overall transportation costs. Most of PacifiCorp's coal reserves are held pursuant to leases from the federal government through the Bureau of Land Management and from certain states and private parties. The leases generally have multi-year terms that may be renewed or extended only with the consent of the lessor and require payment of rents and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities.

Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. Recoverable coal reserves of operating mines as of December 31, 2011, based on PacifiCorp's most recent engineering studies, were as follows (in millions):

Coal Mine	Location	Generating Facility Served	Mining Method	Recoverable Tons	
Bridger	Rock Springs, WY	Jim Bridger	Surface	41	(1)
Bridger	Rock Springs, WY	Jim Bridger	Underground	39	(1)
Deer Creek	Huntington, UT	Huntington, Hunter and Carbon	Underground	27	(2)
Trapper	Craig, CO	Craig	Surface	45	(3)
				152	

(1) These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc. ("PMI") and a subsidiary of Idaho Power Company. PMI, a wholly owned subsidiary of PacifiCorp, has a two-thirds interest in the joint venture. The amounts included above represent only PacifiCorp's two-thirds interest in the coal reserves.

(2) These coal reserves are leased by PacifiCorp and mined by a wholly owned subsidiary of PacifiCorp.

(3) These coal reserves are leased and mined by Trapper Mining, Inc., a cooperative in which PacifiCorp has an ownership interest of 21%. The amount included above represents only PacifiCorp's 21% interest in the coal reserves. PacifiCorp does not operate the Trapper mine.

For surface mine operations, PacifiCorp removes the overburden with heavy earth-moving equipment, such as draglines and power shovels. Once exposed, PacifiCorp drills, fractures and systematically removes the coal using haul trucks or conveyors to transport the coal to the associated generating facility. PacifiCorp reclaims disturbed areas as part of its normal mining activities. After final coal removal, draglines, power shovels, excavators or loaders are used to backfill the remaining pits with the overburden removed at the beginning of the process. Once the overburden and topsoil have been replaced, vegetation and plant life are re-established, and other improvements are made that have local community and environmental benefits. Draglines are used at the Bridger surface mine and draglines with shovels and trucks are used at the Trapper surface mine.

For underground mine operations, a longwall is used as a mechanical shearer to extract coal from long rectangular blocks of medium to thick seams. In longwall mining, PacifiCorp also uses continuous miners to develop access to these long rectangular coal blocks. Hydraulically powered supports temporarily hold up the roof of the mine while a rotating drum mechanically advances across the face of the coal seam, cutting the coal from the face. Chain conveyors then move the loosened coal to an underground mine conveyor system for delivery to the surface. Once coal is extracted from an area, the roof is allowed to collapse in a controlled fashion.

In June 2011, Fossil Rock Fuels LLC, a wholly owned subsidiary of PacifiCorp, acquired the Cottonwood coal reserve lease in Emery County Utah. PacifiCorp intends to mine the Cottonwood coal reserves in the future and has estimated the recoverable tons to be 47 million.

Recoverability by surface mining methods typically ranges from 90% to 95%. Recoverability by underground mining techniques ranges from 50% to 70%. To meet applicable standards, PacifiCorp blends coal mined at its owned mines with contracted coal and utilizes emissions reduction technologies for controlling sulfur dioxide and other emissions. For fuel needs at PacifiCorp's coal-fueled generating facilities in excess of coal reserves available, PacifiCorp believes it will be able to purchase coal under both long- and short-term contracts to supply its generating facilities over their currently expected remaining useful lives.

During the year ended December 31, 2011, PacifiCorp-owned coal-fueled generating facilities held sufficient sulfur dioxide emission allowances to comply with the EPA Title IV requirements. For a further discussion regarding EPA requirements and other environmental laws and regulations, refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K.

PacifiCorp uses natural gas as fuel for its combined- and simple-cycle natural gas-fueled generating facilities. Oil and natural gas are also used for igniter fuel and to fuel generation for transmission support and standby purposes. These sources are presently in adequate supply and available to meet PacifiCorp's needs.

PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses. The FERC regulates 98% of the net capacity of this portfolio through 15 individual licenses, which have terms of 30 to 50 years, while a portion of the portfolio is licensed under the Oregon Hydroelectric Act. For further discussion of PacifiCorp's hydroelectric relicensing and decommissioning activities, including updated information regarding the Klamath River hydroelectric system, refer to Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

PacifiCorp has pursued additional renewable resources as a viable, economical and environmentally prudent means of supplying electricity. Renewable resources have low to no emissions, require little or no fossil fuel and are complemented by PacifiCorp's other generating facilities and wholesale transactions. Wind-powered generating facilities placed in service by December 31, 2012 are eligible for federal renewable electricity production tax credits for 10 years from the date the facilities are placed in service.

PacifiCorp purchases and sells electricity in the wholesale markets as needed to balance its generation and long-term purchase commitments with its retail load and long-term wholesale sales obligations. PacifiCorp may also purchase electricity in the wholesale markets when it is more economical than generating electricity from its own facilities. When prudent, PacifiCorp enters into financial swap contracts and forward electricity sales and purchases for physical delivery at fixed prices to reduce its exposure to electricity price volatility.

Transmission and Distribution

PacifiCorp operates one balancing authority area in the western portion of its service territory and one balancing authority area in the eastern portion of its service territory. A balancing authority area is a geographic area with transmission systems that control generation to maintain schedules with other balancing authority areas and ensure reliable operations. In operating the balancing authority areas, PacifiCorp is responsible for continuously balancing electricity supply and demand by dispatching generating resources and interchange transactions so that generation internal to the balancing authority area, plus net imported power, matches customer loads. PacifiCorp also schedules deliveries of energy over its transmission system in accordance with FERC requirements.

PacifiCorp's transmission system is part of the Western Interconnection, the regional grid in the Western United States. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generation resources to meet its customer load requirements. PacifiCorp's transmission and distribution system included approximately 16,200 miles of transmission lines and 900 substations as of December 31, 2011.

PacifiCorp's Energy Gateway Transmission Expansion Program represents plans to build approximately 2,000 miles of new high-voltage transmission lines, with an estimated cost exceeding $6 billion, primarily in Wyoming, Utah, Idaho and Oregon. The $6 billion estimated cost includes: (a) the 345-kV Populus to Terminal transmission line was fully placed in service in 2010; (b) the 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley expected to be placed in service in 2013; (c) the 345-kV transmission line being built between the Sigurd Substation in central Utah and the Red Butte Substation in southwest Utah expected to be placed in service in 2015; and (d) other segments that are expected to be placed in service through 2021, depending on siting, permitting and construction schedules. The transmission line segments are intended to: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area. Proposed transmission line segments are re-evaluated to ensure optimal benefits and timing before committing to move forward with permitting and construction. Through December 31, 2011, $1.1 billion had been spent and $827 million, including amounts capitalized for equity AFUDC, had been placed in service.

Future Generation

As required by certain state regulations, PacifiCorp uses an Integrated Resource Plan ("IRP") to develop a long-term view of prudent future actions required to help ensure that PacifiCorp continues to provide reliable and cost-effective electric service to its customers while maintaining compliance with existing and evolving environmental laws and regulations. The IRP process identifies the amount and timing of PacifiCorp's expected future resource needs and an associated optimal future resource mix that accounts for planning uncertainty, risks, reliability impacts, state energy policies and other factors. The IRP is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. PacifiCorp files its IRP on a biennial basis, and receives a formal notification in five states as to whether the IRP meets the commission's IRP standards and guidelines, which is referred to as "acknowledgment." In March 2011, PacifiCorp filed its 2011 IRP with the state commissions. In June 2011, an addendum to the 2011 IRP with supplemental resource analysis was filed with the state commissions. PacifiCorp has received acknowledgment of its 2011 IRP from the WPSC, the WUTC and the IPUC. In January 2012, PacifiCorp filed an updated 2011 IRP action plan with the OPUC containing additional details to respond to issues raised by parties to the acknowledgment proceedings.

Demand-side Management

PacifiCorp has provided a comprehensive set of DSM programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. PacifiCorp offers services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs such as PacifiCorp's residential and small commercial air conditioner load control program and irrigation equipment load control programs. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency surcharges to retail customers or for recovery of costs through regulated rates. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 305 MW of load reduction when needed. Recovery of the costs associated with the large industrial load management program is determined through PacifiCorp's general rate case process. During 2011, $114 million was expended on PacifiCorp's DSM programs resulting in an estimated 539,197 MWh of first-year energy savings and an estimated 467 MW of peak load management. Total demand-side load available for control during 2011, including both load management from the large industrial curtailment contracts and DSM programs, was 719 MW.

MidAmerican Energy

General

MidAmerican Energy, an indirect wholly owned subsidiary of MEHC, is a United States regulated electric and natural gas utility company headquartered in Iowa that serves 0.7 million regulated retail electric customers in portions of Iowa, Illinois and South Dakota and 0.7 million regulated retail and transportation natural gas customers in portions of Iowa, South Dakota, Illinois and Nebraska. MidAmerican Energy is principally engaged in the business of generating, transmitting, distributing and selling electricity and in distributing, selling and transporting natural gas. MidAmerican Energy has a diverse customer base consisting of residential, agricultural and a variety of commercial and industrial customer groups. Some of the larger industrial groups served by MidAmerican Energy include the processing and sales of food products; the manufacturing, processing and fabrication of primary metals; farm and other non-electrical machinery; real estate; and cement and gypsum products. In addition to retail sales and natural gas transportation, MidAmerican Energy sells electricity to markets operated by RTOs and electricity and natural gas to other utilities and market participants on a wholesale basis. MidAmerican Energy is a transmission-owning member of the MISO and participates in its energy and ancillary services markets.

MidAmerican Energy's regulated electric and natural gas operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The franchise agreements, with various expiration dates, are typically for 20- to 25-year terms. Several of these franchise agreements allow the municipality the right to seek amendment to the franchise agreement at a specified time during the term. MidAmerican Energy generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electricity service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow MidAmerican Energy an opportunity to recover its costs of providing services and to earn a reasonable return on its investment.

MidAmerican Energy has nonregulated business activities that consist of competitive electricity and natural gas retail sales and natural gas income-sharing arrangements. Nonregulated electric activities predominantly include sales to retail customers in Illinois, Texas and other states that allow customers to choose their energy supplier. Nonregulated natural gas activities predominately include sales to retail customers in Iowa and Illinois. For its nonregulated retail energy activities, MidAmerican Energy purchases electricity and natural gas from producers and third party energy marketing companies and sells it directly to commercial and industrial end-users. MidAmerican Energy does not own nonregulated electricity or natural gas production assets, but hedges its contracted retail obligations either with physical supply arrangements or financial products. As of December 31, 2011, MidAmerican Energy had contracts in place for the retail sale of electricity and natural gas totaling 17,515,000 MWh and 25,112,000 Dth, respectively, with weighted average lives of 1.3 years and 1.0 years, respectively. In addition, MidAmerican Energy manages natural gas supplies for a number of smaller commercial end-users, which includes the sale of natural gas to these customers to meet their supply requirements.

The percentages of MidAmerican Energy's operating revenue derived from the following business activities for the years ended December 31 were as follows:

	2011	2010	2009
Regulated electric	47%	47%	47%
Regulated gas	22	22	23
Nonregulated and other	31	31	30
	100%	100%	100%

Regulated Electric Operations

Customers

The GWh and percentages of electricity sold to retail customers by jurisdiction for the years ended December 31 were as follows:

	2011		2010		2009	
Iowa	19,597	90%	19,435	90%	18,074	90%
Illinois	2,066	9	2,059	9	1,908	9
South Dakota	210	1	216	1	203	1
	21,873	100%	21,710	100%	20,185	100%

Electricity sold to retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2011		2010		2009	
GWh sold:						
Residential	6,476	20%	6,549	19%	5,907	18%
Commercial	4,189	13	4,226	12	4,093	12
Industrial	9,586	29	9,310	27	8,627	26
Other	1,622	5	1,625	4	1,558	4
Total retail	21,873	67	21,710	62	20,185	60
Wholesale	10,584	33	13,130	38	13,424	40
Total GWh sold	32,457	100%	34,840	100%	33,609	100%
Average number of retail customers (in thousands):						
Residential	630	86%	627	86%	624	86%
Commercial	84	12	84	12	83	12
Industrial	2	—	2	—	2	—
Other	14	2	14	2	14	2
Total	730	100%	727	100%	723	100%

In addition to the variations in weather from year to year, fluctuations in economic conditions within the service territory and elsewhere can impact customer usage, particularly for industrial and wholesale customers. The increase in retail demand during 2010 was substantially the result of weather and higher industrial customer usage driven by improved economic conditions in the United States compared to 2009. The decrease in wholesale sales for 2011 compared to 2010 was driven primarily by the impact of lower market prices.

There are seasonal variations in MidAmerican Energy's electric business that are principally related to the use of electricity for air conditioning and the related effects of weather. Typically, 35-40% of MidAmerican Energy's regulated electric revenue is reported in the months of June, July, August and September.

The annual hourly peak demand on MidAmerican Energy's electric system usually occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. On July 19, 2011, retail customer usage of electricity caused a record hourly peak demand of 4,752 MW on MidAmerican Energy's electric distribution system, which is 237 MW greater than the previous peak demand of 4,515 MW set July 14, 2010.

Generating Facilities and Fuel Supply

MidAmerican Energy has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding MidAmerican Energy's owned generating facilities as of December 31, 2011:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MW)[1]	Net Owned Capacity (MW)[1]
COAL:					
Walter Scott, Jr. Nos. 1, 2, 3 and 4	Council Bluffs, IA	Coal	1954-2007	1,642	1,167
George Neal Nos. 1, 2 and 3	Sergeant Bluff, IA	Coal	1964-1975	956	810
Louisa	Muscatine, IA	Coal	1983	750	660
Ottumwa	Ottumwa, IA	Coal	1981	664	345
George Neal No. 4	Salix, IA	Coal	1979	645	262
Riverside Nos. 3 and 5	Bettendorf, IA	Coal	1925-1961	137	137
				4,794	3,381
NATURAL GAS:					
Greater Des Moines	Pleasant Hill, IA	Natural gas	2003-2004	495	495
Electrifarm	Waterloo, IA	Natural gas/oil	1975-1978	189	189
Pleasant Hill	Pleasant Hill, IA	Natural gas/oil	1990-1994	157	157
Sycamore	Johnston, IA	Natural gas/oil	1974	149	149
River Hills	Des Moines, IA	Natural gas	1966-1967	121	121
Coralville	Coralville, IA	Natural gas	1970	65	65
Moline	Moline, IL	Natural gas	1970	58	58
Parr	Charles City, IA	Natural gas	1969	33	33
28 portable power modules	Various	Oil	2000	56	56
				1,323	1,323
WIND:					
Rolling Hills	Massena, IA	Wind	2011	444	444
Pomeroy	Pomeroy, IA	Wind	2007-2011	286	286
Century	Blairsburg, IA	Wind	2005-2008	200	200
Intrepid	Schaller, IA	Wind	2004-2005	176	176
Adair	Adair, IA	Wind	2008	175	175
Walnut	Walnut, IA	Wind	2008	153	153
Carroll	Carroll, IA	Wind	2008	150	150
Laurel	Laurel, IA	Wind	2011	120	120
Victory	Westside, IA	Wind	2006	99	99
Charles City	Charles City, IA	Wind	2008	75	75
				1,878	1,878
NUCLEAR:					
Quad Cities Nos. 1 and 2	Cordova, IL	Uranium	1972	1,760	440
OTHER:					
Moline Nos. 1-4	Moline, IL	Hydroelectric	1941	3	3
Total Available Generating Capacity				9,758	7,025
PROJECTS UNDER CONSTRUCTION[2]:					
Various wind projects	Iowa	Wind		407	407
				10,165	7,432

(1) Facility Net Capacity represents (except for wind-powered generating facilities, which are nominal ratings) total facility accredited net generating capacity based on MidAmerican Energy's accreditation approved by the MISO. A wind turbine generator's nominal rating is the manufacturer's contractually specified capability (in MW) under specified conditions. The accreditation of the wind-powered generating facilities totaled 172 MW and is considerably less than the nominal ratings due to the varying nature of wind. Additionally, the Laurel and Rolling Hills wind-powered generating facilities and 30 MW of the Pomeroy wind-powered generating facility were placed in service in late 2011 and were not yet accredited by the MISO. Net Owned Capacity indicates MidAmerican Energy's ownership of Facility Net Capacity.

(2) Facility Net Capacity and Net Owned Capacity for projects under construction each represent the estimated nominal ratings.

The following table shows the percentages of MidAmerican Energy's total energy supplied by energy source for the years ended December 31:

	2011	2010	2009
Coal	64%	66%	60%
Nuclear	11	11	11
Natural gas	1	2	1
Other(1)	13	10	10
Total energy generated	89	89	82
Energy purchased - short-term contracts and other	10	10	11
Energy purchased - long-term contracts	1	1	7
	100%	100%	100%

(1) All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with RPS or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

The percentage of MidAmerican Energy's energy supplied by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages; fuel commodity prices; fuel transportation costs; weather; environmental considerations; transmission constraints; and wholesale market prices of electricity. When factors for one energy source are less favorable, MidAmerican Energy must place more reliance on other energy sources. For example, MidAmerican Energy can generate more electricity using its low cost wind-powered generating facilities when factors associated with these facilities are favorable. When factors associated with wind resources are less favorable, MidAmerican Energy must increase its reliance on more expensive generation or purchased electricity. MidAmerican Energy manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives, including forwards, futures, options, swaps and other agreements. Refer to Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

All of the coal-fueled generating facilities operated by MidAmerican Energy are fueled by low-sulfur, western coal from the Powder River Basin in northeast Wyoming. MidAmerican Energy's coal supply portfolio includes multiple suppliers and mines under short-term and multi-year agreements of varying terms and quantities. MidAmerican Energy's coal supply portfolio has all of its expected 2012 requirements under fixed-price contracts. MidAmerican Energy regularly monitors the western coal market for opportunities to enhance its coal supply portfolio. During the year ended December 31, 2011, MidAmerican Energy-owned generating facilities held sufficient allowances for sulfur dioxide and nitrogen oxides emissions to comply with the EPA Title IV and CAIR or CSAPR requirements. For a further discussion regarding EPA requirements and other environmental laws and regulations, refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K.

MidAmerican Energy has a long-haul coal transportation agreement with Union Pacific Railroad Company ("Union Pacific") that expires in 2012. Under this agreement, Union Pacific delivers coal directly to MidAmerican Energy's George Neal and Walter Scott, Jr. Energy Centers and to an interchange point with Canadian Pacific Railway for short-haul delivery to the Louisa and Riverside Energy Centers. MidAmerican Energy has the ability to use BNSF Railway Company, an affiliate company, for delivery of coal to the Walter Scott, Jr., Louisa and Riverside Energy Centers should the need arise.

MidAmerican Energy is a 25% joint owner of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station"), a nuclear power plant. Exelon Generation Company, LLC ("Exelon Generation"), the 75% joint owner and the operator of Quad Cities Station, is a subsidiary of Exelon Corporation. Approximately one-third of the nuclear fuel assemblies in each reactor core at Quad Cities Station is replaced every 24 months. MidAmerican Energy has been advised by Exelon Generation that the following requirements for Quad Cities Station can be met under existing supplies or commitments: uranium requirements through 2015 and partial requirements through 2020; uranium conversion requirements through 2015 and partial requirements through 2020; enrichment requirements through 2015 and partial requirements through 2028; and fuel fabrication requirements through 2019. MidAmerican Energy has been advised by Exelon Generation that it does not anticipate it will have difficulty in contracting for uranium, uranium conversion, enrichment or fabrication of nuclear fuel needed to operate Quad Cities Station during these time periods.

MidAmerican Energy uses natural gas and oil as fuel for intermediate and peak demand electric generation, igniter fuel, transmission support and standby purposes. These sources are presently in adequate supply and available to meet MidAmerican Energy's needs.

MidAmerican Energy owns more wind-powered generating capacity than any other United States rate-regulated electric utility and believes wind-powered generation offers a viable, economical and environmentally prudent means of supplying electricity. Pursuant to ratemaking principles approved by the IUB, all of MidAmerican Energy's wind-powered generating facilities in service at December 31, 2011 are authorized to earn a fixed rate of return on equity over their useful lives ranging from 11.7% to 12.2% in any future Iowa rate proceeding. Additionally, MidAmerican Energy is constructing 407 MW (nominal ratings) of wind-powered generation that it expects to place in service by December 31, 2012, which are authorized to earn a 12.2% return on equity in any future Iowa rate proceeding. Renewable resources have low to no emissions, require little or no fossil fuel and are complemented by MidAmerican Energy's other generating facilities and wholesale transactions. Wind-powered generating facilities placed in service by December 31, 2012 are eligible for federal renewable electricity production tax credits for 10 years from the date the facilities are placed in-service.

MidAmerican Energy purchases and sells electricity and ancillary services in the wholesale markets as needed to balance its generation and long-term purchase commitments with its retail load and long-term wholesale sales obligations. MidAmerican Energy may also purchase electricity in the wholesale markets when it is more economical than generating electricity from its own facilities. MidAmerican Energy utilizes both swaps and fixed-price electricity sales and purchases contracts to reduce its exposure to electricity price volatility.

MidAmerican Energy can enter into wholesale bilateral transactions with a number of parties within the MISO market footprint and can also participate directly in the MISO market. MidAmerican Energy's wholesale transactions can also occur through the Southwest Power Pool, Inc. ("SPP") and PJM Interconnection, L.L.C. ("PJM") RTOs and several other major transmission-owning utilities in the region as a result of transmission interconnections the MISO has with such organizations.

Transmission and Distribution

MidAmerican Energy's transmission and distribution systems included 2,300 miles of transmission lines and 400 substations as of December 31, 2011. Electricity from MidAmerican Energy's generating facilities and purchased electricity is delivered to wholesale markets and its retail customers via the transmission facilities of MidAmerican Energy and others. MidAmerican Energy determined that participation in an RTO energy and ancillary services market as a transmission-owning member would be superior to continuing as a stand-alone balancing control area and provide MidAmerican Energy with enhanced wholesale marketing opportunities and improved economic dispatch of its generating facilities. Effective September 1, 2009, MidAmerican Energy integrated its transmission facilities with the MISO as a transmission-owning member. Accordingly, MidAmerican Energy now operates its transmission assets at the direction of the MISO.

The MISO manages its energy and ancillary service markets using reliability-constrained economic dispatch of the region's generation. Every five minutes, the MISO analyzes generation commitments to provide market liquidity and transparent pricing while minimizing congestion and maximizing efficient energy transmission. Additionally, the MISO provides transmission service to MidAmerican Energy and others through its open access transmission tariff throughout the MISO footprint.

The long-term transmission planning function is also performed by the MISO through its tariff. Recently, the MISO received FERC approval on changes to this tariff that allows for broad cost allocation for certain types of Multi-Value Projects ("MVP"). The MISO has identified 17 candidate projects that provide multiple benefits and will qualify for broad cost allocation under their tariff. Four of these candidate projects are expected to be part of the MidAmerican Energy transmission system and owned and operated by MidAmerican Energy. While the analyses performed by the MISO in relation to the MVP demonstrate benefits that exceed costs for the RTO as a whole, the experience for individual members may not necessarily be consistent with that of the MISO as a whole. Therefore, while it is believed that the MISO's transmission system improvements will be beneficial to MidAmerican Energy, incremental charges could exceed incremental benefits.

Regulated Natural Gas Operations

MidAmerican Energy is engaged in the procurement, transportation, storage and distribution of natural gas for customers in its service territory. MidAmerican Energy purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the gas from the production areas to MidAmerican Energy's service territory and for storage services to manage fluctuations in system demand and seasonal pricing. MidAmerican Energy sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for a number of end-use customers who have independently secured their supply of natural gas. During 2011, 49% of the total natural gas delivered through MidAmerican Energy's distribution system was transportation service.

The percentages of natural gas sold to retail customers by jurisdiction for the years ended December 31 were as follows:

	2011	**2010**	**2009**
Iowa	76%	77%	76%
South Dakota	13	12	13
Illinois	10	10	10
Nebraska	1	1	1
	100%	100%	100%

The percentages of natural gas sold to retail and wholesale customers by class of customer, total Dth of natural gas sold, total Dth of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2011	**2010**	**2009**
Residential	49%	45%	42%
Commercial(1)	24	22	22
Industrial(1)	4	4	4
Total retail	77	71	68
Wholesale(2)	23	29	32
	100%	100%	100%
Total Dth of natural gas sold (000's)	100,154	112,117	121,355
Total Dth of transportation service (000's)	73,045	71,185	69,642
Total average number of retail customers (in millions)	0.7	0.7	0.7

(1) Commercial and industrial customers are classified primarily based on the nature of their business and natural gas usage. Commercial customers are non-residential customers that use natural gas principally for heating. Industrial customers are non-residential customers that use natural gas principally for their manufacturing processes.

(2) Wholesale sales are generally made to other utilities, municipalities and energy marketing companies for eventual resale to end-use customers.

There are seasonal variations in MidAmerican Energy's regulated natural gas business that are principally due to the use of natural gas for heating. Typically, 50-60% of MidAmerican Energy's regulated natural gas revenue is reported in the months of January, February, March and December.

On January 15, 2009, MidAmerican Energy recorded its all-time highest peak-day delivery through its distribution system of 1,155,473 Dth. This peak-day delivery consisted of 74% traditional retail sales service and 26% transportation service. MidAmerican Energy's 2011/2012 winter heating season has been mild to date and the peak-day delivery as of February 10, 2012 was 949,368 Dth reached on January 19, 2012. This preliminary peak-day delivery included 68% traditional retail sales service and 32% transportation service.

Fuel Supply and Capacity

MidAmerican Energy is allowed to recover its cost of natural gas from all of its regulated retail natural gas customers through purchased gas adjustment clauses ("PGA"). Accordingly, as long as MidAmerican Energy is prudent in its procurement practices, MidAmerican Energy's regulated retail natural gas customers retain the risk associated with the market price of natural gas. MidAmerican Energy uses several strategies designed to reduce volatility of natural gas prices for its regulated retail natural gas customers while maintaining system reliability. These strategies include purchasing a geographically diverse supply portfolio from producers and third party energy marketing companies, the use of storage gas and peaking facilities, short- and long-term financial and physical gas purchase contracts and regulatory arrangements to share savings and costs with customers.

MidAmerican Energy contracts for firm natural gas pipeline capacity to transport natural gas from production areas to its service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems, including Northern Natural Gas.

MidAmerican Energy utilizes natural gas storage leased from interstate pipelines to meet retail customer requirements and to manage the daily changes in demand due to changes in weather. The storage gas is typically replaced during off-peak months when the demand for natural gas is historically lower than during the heating season. In addition, MidAmerican Energy also utilizes its three LNG facilities to meet peak day demands in the winter. The leased storage and LNG facilities reduce MidAmerican Energy's dependence on natural gas purchases during the volatile winter heating season and can deliver approximately 50% of MidAmerican Energy's design day retail sales requirements.

Natural gas property consists primarily of natural gas mains and services lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of MidAmerican Energy included 22,000 miles of natural gas mains and service lines as of December 31, 2011.

Demand-side Management

MidAmerican Energy has provided a comprehensive set of DSM programs to its Iowa electric and gas customers since 1990 and to customers in its other jurisdictions in more recent years. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, MidAmerican Energy offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the nonresidential load management program. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency service charges paid by all retail electric and gas customers. During 2011, $75 million was expended on MidAmerican Energy's DSM programs resulting in an estimated 212,000 MWh of electric and 468,000 Dth of gas first-year energy savings and an estimated 375 MW of electric and 5,407 Dth per day of gas peak load management.

MidAmerican Energy Pipeline Group

The MidAmerican Energy Pipeline Group consists of MEHC's interstate natural gas pipeline companies, Northern Natural Gas and Kern River.

Northern Natural Gas

Northern Natural Gas, an indirect wholly owned subsidiary of MEHC, owns one of the largest interstate natural gas pipeline systems in the United States, which reaches from southern Texas to Michigan's Upper Peninsula. Northern Natural Gas primarily transports and stores natural gas for utilities, municipalities, other pipeline companies, gas marketing companies, industrial and commercial users and other end-users. During 2011, Northern Natural Gas' transportation and storage revenue accounted for 91% of its total operating revenue, of which 90% was generated from reservation demand charges under firm transportation and storage contracts. About 64% of the reservation demand charges under the firm transportation and storage contracts were from utilities. Except for quantities of natural gas owned and managed for operational and system balancing purposes, Northern Natural Gas does not own the natural gas that is transported through its system. The sale of natural gas for operational and system balancing purposes accounts for the majority of the remaining 9% of Northern Natural Gas' 2011 operating revenue. Northern Natural Gas' transportation and most of its storage operations are subject to a regulated tariff that is on file with the FERC. The tariff rates are designed to provide Northern Natural Gas with an opportunity to recover its costs of providing services and earn a reasonable return on its investments.

Northern Natural Gas' pipeline system, which is interconnected with many interstate and intrastate pipelines in the national grid system, consists of two distinct, but operationally integrated, systems. Its traditional end-use and distribution market area in the northern part of its system, referred to as the Market Area, includes points in Iowa, Nebraska, Minnesota, Wisconsin, South Dakota, Michigan and Illinois. Its natural gas supply and delivery service area in the southern part of its system, referred to as the Field Area, includes points in Kansas, Texas, Oklahoma and New Mexico. Northern Natural Gas' pipeline system consists of 14,900 miles of natural gas pipelines, including 6,500 miles of mainline transmission pipelines and 8,400 miles of branch and lateral pipelines, with a Market Area design capacity of 5.5 Bcf per day, a Field Area delivery capacity of 2.0 Bcf per day to the Market Area and 73 Bcf of storage cycle capacity in five storage facilities. Northern Natural Gas' pipeline system is configured with approximately 2,400 active receipt and delivery points (excluding farm taps) which are integrated with the facilities of LDCs. Many of Northern Natural Gas' LDC customers are part of combined utilities that also use natural gas as a fuel source for electric generation. Northern Natural Gas delivers approximately 0.9 Tcf of natural gas to its customers annually. Based on review of the relevant 2010 industry data, Northern Natural Gas' system is the largest single pipeline in the United States as measured by pipeline miles.

Northern Natural Gas has access to multiple supply basins. The pipeline is positioned such that direct access is available from producers in the Anadarko, Permian and Hugoton basins with increased production from shale and tight sands formations adjacent to Northern Natural Gas' pipeline. During 2011, the pipeline connected over 250,000 Dth per day of supply access from the Wolfberry shale formation in west Texas and from the Granite Wash tight sands formations in the Texas panhandle and in Oklahoma. Additionally, because of its location and multiple interconnections with several interstate and intrastate pipelines, with receipt, delivery or bi-directional capabilities, Northern Natural Gas also accesses significant natural gas supplies from the Rocky Mountains and Western Canadian Basins. The Rocky Mountains Basin is accessed through interconnects with Trailblazer Pipeline Company, Kinder Morgan Interstate Gas Transmission, LLC, Cheyenne Plains Gas Pipeline Company, LLC, Colorado Interstate Gas Pipeline Company and Rockies Express Pipeline, LLC ("REX"). The Western Canadian production areas are accessed through Northern Border Pipeline Company ("Northern Border"), Great Lakes Gas Transmission Limited Partnership ("Great Lakes") and Viking Gas Transmission Company ("Viking"). This supply diversity and access to both stable and growing production areas provides significant flexibility to Northern Natural Gas' system and customers.

During 2011, 79% of Northern Natural Gas' transportation and storage revenue was generated from Market Area customer transportation contracts, of which 93% was generated from reservation demand charges and the balance from usage charges. Northern Natural Gas transports natural gas primarily to local distribution markets and end-users in the Market Area. Northern Natural Gas directly serves 78 utilities, including MidAmerican Energy, and in turn, these utilities serve numerous residential, commercial and industrial customers. A majority of Northern Natural Gas' capacity in the Market Area is committed to customers under firm transportation contracts, where customers pay Northern Natural Gas a monthly reservation charge for the right to transport natural gas through Northern Natural Gas' system. As of December 31, 2011, 58% of Northern Natural Gas' customers' entitlement in the Market Area is contracted beyond 2015. The weighted average remaining contract term for Northern Natural Gas' Market Area firm transportation contracts is approximately four years as of December 31, 2011.

During 2011, 10% of Northern Natural Gas' transportation and storage revenue was generated from Field Area customer transportation contracts. In the Field Area, customers holding entitlement consist primarily of energy marketing companies, producers, midstream gatherers and producers, and power generators. The majority of this entitlement is contracted on a short-term basis. Northern Natural Gas expects the current level of Field Area contracting to continue in the foreseeable future, as Market Area customers presently need to purchase competitively-priced supplies from the Field Area to support their existing and growth demand requirements. However, the revenue received from these contracts is expected to vary in relationship to the difference, or "spread," in natural gas prices between the MidContinent and Permian Regions and the price of the alternative supplies that are available to Northern Natural Gas' Market Area.

During 2011, 11% of Northern Natural Gas' transportation and storage revenue was generated from storage services. Northern Natural Gas' storage services are provided through the operation of one underground natural gas storage field in Iowa, two underground natural gas storage facilities in Kansas and two LNG storage peaking units, one in Iowa and one in Minnesota. The three underground natural gas storage facilities and two LNG storage peaking units have a total firm service and operational storage cycle capacity of 73 Bcf and over 2.0 Bcf of peak day delivery capability. These storage facilities provide operational flexibility for the daily balancing of Northern Natural Gas' system and provide services to customers to meet their winter peaking and year-round load swing requirements.

Since June 2006, Northern Natural Gas has added 14 Bcf of firm storage cycle capacity through investments and modifications made at its Cunningham, Kansas and Redfield, Iowa storage facilities. This capacity was sold to LDCs for terms of 20-21 years.

Northern Natural Gas' system experiences significant seasonal swings in demand and revenue, with the highest demand typically occurring during the months of November through March. This seasonality provides Northern Natural Gas with opportunities to deliver additional value-added services, such as firm and interruptible storage services. As a result of Northern Natural Gas' geographic location in the middle of the United States and its many interconnections with other pipelines, Northern Natural Gas has the opportunity to augment its steady end user and LDC revenue by capitalizing on opportunities for shippers to reach additional markets, such as Chicago, Illinois, other parts of the Midwest, and Texas, through interconnects.

Kern River

Kern River, an indirect wholly owned subsidiary of MEHC, owns an interstate natural gas pipeline system that extends from supply areas in the Rocky Mountains to consuming markets in Utah, Nevada and California. Kern River's pipeline system consists of 1,700 miles of natural gas pipelines, including 1,400 miles of mainline section and 300 miles of common facilities, with a design capacity of 2,166,575 Dth per day. Kern River owns the entire mainline section, which extends from the system's point of origination near Opal, Wyoming, through the Central Rocky Mountains area into Daggett, California. The mainline section consists of 1,300 miles of 36-inch diameter pipeline and 100 miles of various laterals that connect to the mainline. The common facilities are jointly owned by Kern River and Mojave Pipeline Company ("Mojave"), a wholly owned subsidiary of El Paso Corporation, as tenants-in-common, and ownership may increase or decrease pursuant to the capital contributions made by each respective joint owner. Kern River has exclusive rights to 1,613,400 Dth per day of the common facilities' capacity, and Mojave has exclusive rights to 414,000 Dth per day of capacity. Operation and maintenance of the common facilities are the responsibility of Mojave Pipeline Operating Company, an affiliate of Mojave. Except for quantities of natural gas owned for operational purposes, Kern River does not own the natural gas that is transported through its system. Kern River's transportation operations are subject to a regulated tariff that is on file with the FERC. The tariff rates are designed to provide Kern River with an opportunity to recover its costs of providing services and earn a reasonable return on its investments.

Kern River has completed two significant expansion projects in the last two years. The 2010 Expansion project was placed in service in April 2010 and added 145,000 Dth per day of capacity. The Apex Expansion project was placed in service in October 2011 and added 266,000 Dth per day of capacity.

Over 95% of Kern River's design capacity of 2,166,575 Dth per day is contracted pursuant to long-term firm natural gas transportation service agreements, whereby Kern River receives natural gas on behalf of customers at designated receipt points and transports the natural gas on a firm basis to designated delivery points. In return for this service, each customer pays Kern River a fixed monthly reservation fee based on each customer's maximum daily quantity and a commodity charge based on the actual amount of natural gas transported pursuant to its long-term firm natural gas transportation service agreements and Kern River's tariff.

These long-term firm natural gas transportation service agreements expire between April 30, 2013 and September 30, 2031 and have a weighted-average remaining contract term of eight years. Kern River's customers include electric utilities and natural gas distribution utilities, major oil and natural gas companies or affiliates of such companies, electricity generating companies, energy marketing and trading companies, and financial institutions. The utilities provide services in Utah, Nevada and California. As of December 31, 2011, nearly 85% of the firm capacity under contract has primary delivery points in California, with the flexibility to access secondary delivery points in Nevada and Utah.

Competition

The Pipeline Companies compete with other pipelines on the basis of cost, which includes both the natural gas commodity cost and its transportation cost, flexibility, reliability of service and overall customer service. Natural gas also competes with alternative energy sources, including coal, nuclear energy, wind, geothermal, solar and fuel oil. Legislation and governmental regulations, the weather, the futures market, production costs and other factors beyond the control of the Pipeline Companies influence the price of the natural gas commodity.

The natural gas industry is undergoing a significant shift in supply sources. Production from conventional sources continues to decline while production from unconventional sources, such as shale gas, is rapidly increasing. This shift will affect the supply patterns, the flows and rates that may be charged on pipeline systems. The impact will vary among pipelines according to the location and the number of competitors attached to these new supply sources.

Electric power generation has been the source of most of the growth in demand for natural gas over the last 10 years, and this trend is expected to continue in the future. The growth of natural gas in this sector is influenced by regulation, competition with other energy sources, primarily coal, and increased consumption of electricity as a result of economic growth. Short-term market shifts have been driven by relative costs of coal-fueled generation versus natural gas-fueled generation. A long-term shift away from the use of coal in power generation could be driven by environmental regulations. The future demand for natural gas could be increased by regulations limiting or discouraging coal use. However, natural gas demand could potentially be adversely affected by laws mandating or encouraging renewable power sources that produce fewer GHG emissions than natural gas.

The Pipeline Companies' ability to extend existing customer contracts, remarket expiring contracted capacity or market new capacity is dependent on competitive alternatives, the regulatory environment and the market supply and demand factors at the relevant dates these contracts are eligible to be renewed or extended. The duration of new or renegotiated contracts will be affected by current commodity and transportation prices, competitive conditions and customers' judgments concerning future market trends and volatility.

Subject to regulatory requirements, the Pipeline Companies attempt to recontract or remarket capacity at the maximum rates allowed under their tariffs, although at times the Pipeline Companies discount these rates to remain competitive. The Pipeline Companies' existing contracts mature at various times and in varying amounts of entitlement. The Pipeline Companies manage the recontracting process to mitigate the risk of a significant negative impact on operating revenue.

Historically, the Pipeline Companies have been able to provide competitively priced services because of access to a variety of relatively low cost supply basins, cost control measures and the relatively high level of firm entitlement that is sold on a seasonal and annual basis, which lowers the per unit cost of transportation. To date, the Pipeline Companies have avoided significant pipeline system bypasses and have not experienced any significant non-renewal of firm contracts; however, there could be contracts turned back in the future.

Northern Natural Gas' major competitors in the Market Area include ANR Pipeline Company, Northern Border and Natural Gas Pipeline Company of America LLC. Other competitors include Great Lakes and Viking. In the Field Area, where the vast majority of Northern Natural Gas' capacity is used for transportation services provided on a short-term firm basis, Northern Natural Gas competes with a large number of interstate and intrastate pipeline companies.

With respect to the Field area, Northern Natural Gas believes that the current level of contracting is sustainable to support the firm requirements of Northern Natural Gas' Market Area customers. Generally, the take-away capacity at the Field-Market demarcation point between Northern Natural Gas' Field and Market Areas is fully contracted by Northern Natural Gas' Market Area customers.

Northern Natural Gas needs to compete aggressively to serve existing load and add new customers and load. Northern Natural Gas has been successful in competing for a significant amount of the increased demand related to residential and commercial needs and the construction of new power plants. The growth related to utilities has historically been driven by population growth and increased commercial and industrial needs. The new power plant growth originates from re-powering coal-fueled generation, as well as new combustion and combined-cycle gas-fueled generation. The growth also may be supportive of the continued sale of Northern Natural Gas' storage services and Field Area transportation services.

Kern River competes with various interstate pipelines in developing expansion projects and entering into long-term agreements to serve market growth in Southern California; Las Vegas, Nevada; and Salt Lake City, Utah. Kern River also competes with various interstate pipelines and their customers to market unutilized capacity under shorter term transactions. Kern River provides its customers with supply diversity through pipeline interconnections with Northwest Pipeline Corporation, Colorado Interstate, Overland Trails Pipeline Company, Questar Pipeline Company, and Questar Overthrust Pipeline Company and through indirect pipeline interconnections with Wyoming Interstate Company and REX. These interconnections, in addition to the direct interconnections to natural gas processing facilities, allow Kern River to access natural gas reserves in Colorado, northwestern New Mexico, Wyoming, Utah and the Western Canadian Sedimentary Basin.

Kern River is the only interstate pipeline that presently delivers natural gas directly from the Rocky Mountain gas supply basin to end-users in the Southern California market. This enables direct connect customers to avoid paying a "rate stack" (i.e., additional transportation costs attributable to the movement from one or more interstate pipeline systems to an intrastate system within California). Kern River's levelized rate structure and access to upstream pipelines, storage facilities and economic Rocky Mountain gas reserves increases its competitiveness and attractiveness to end-users. Kern River believes it has an advantage relative to other interstate pipelines serving Southern California because its relatively new pipeline can be economically expanded and has required significantly less capital expenditures and ongoing maintenance than other systems to comply with the Pipeline Safety Improvement Act of 2002. Kern River's favorable market position is tied to the availability and relatively favorable price of gas reserves in the Rocky Mountain area, an area that has attracted considerable expansion of pipeline capacity serving markets other than Southern California and Nevada.

During 2011, Northern Natural Gas had three customers, including MidAmerican Energy, that each accounted for greater than 10% of its transportation and storage revenue and its ten largest customers accounted for 65% of its system-wide transportation and storage revenue. Northern Natural Gas has agreements to retain the vast majority of its two largest non-affiliated customers' volumes through at least 2017. During 2011, Kern River had one customer who accounted for greater than 10% of its revenue. The loss of any of these significant customers, if not replaced, could have a material adverse effect on the Pipeline Companies' respective businesses.

Northern Powergrid Holdings

General

Northern Powergrid Holdings, an indirect wholly owned subsidiary of MEHC, is a holding company which owns two companies that distribute electricity in Great Britain, Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc. The Distribution Companies serve 3.9 million end-users and operate in the north-east of England from North Northumberland through Tyne and Wear, County Durham, Cleveland and Yorkshire to North Lincolnshire, an area covering 10,000 square miles. The principal function of the Distribution Companies is to build, maintain and operate the electricity distribution network through which the end-user receives a supply of electricity. In addition to the Distribution Companies, Northern Powergrid Holdings also owns an engineering contracting business that provides electrical infrastructure contracting services to third parties and a hydrocarbon exploration and development business that is focused on developing integrated upstream gas projects in Europe and Australia.

Electricity Distribution

The Distribution Companies receive electricity from the national grid transmission system and distribute it to end-users' premises using their networks of transformers, switchgear and distribution lines and cables. Substantially all of the end-users in the Distribution Companies' distribution service areas are connected to the Distribution Companies' networks and electricity can only be delivered to these end-users through their distribution systems, thus providing the Distribution Companies with distribution volumes that are relatively stable from year to year. The Distribution Companies charge fees for the use of their distribution systems to the suppliers of electricity. The suppliers purchase electricity from generators, sell the electricity to end-user customers and use the Distribution Companies' distribution networks pursuant to an industry standard "Distribution Connection and Use of System Agreement." One supplier, RWE Npower PLC and certain of its affiliates, represented 29% of the total combined distribution revenue of the Distribution Companies during 2011.

The service territory geographically features a diverse economy with no dominant sector. The mix of rural, agricultural, urban and industrial areas covers a broad customer base ranging from domestic usage through farming and retail to major industry including automotives, chemicals, mining, steelmaking and offshore marine construction. The industry within the area is concentrated around the principal centers of Newcastle, Middlesbrough, Sheffield and Leeds.

The price controlled revenue of the regulated distribution companies is set out in the special conditions of the licenses of those companies. The licenses are enforced by the regulator, the Gas and Electricity Markets Authority through its office of gas and electric markets (known as "Ofgem") and limit increases (or may require decreases) based upon the rate of inflation, other specified factors and other regulatory action. Changes to the price controls can be made only by agreement between a distribution company and the regulator or, if there is no agreement, following a report on a reference by the regulator to the Competition Commission. It has been the convention in the United Kingdom for regulators to conduct periodic regulatory reviews before making proposals for any changes to the price controls. The current electricity distribution price control became effective April 1, 2010 and is expected to continue through March 31, 2015. Ofgem has indicated that future price controls are likely to be set for a period of eight or nine years, with the potential for a mid-period review if the outputs required of a licensee have changed.

GWh and percentages of electricity distributed to end-users and the total number of end-users as of and for the years ended December 31 were as follows:

	2011		**2010**		**2009**	
Northern Powergrid (Northeast) Limited:						
Residential	5,437	35%	5,764	36%	5,610	36%
Commercial	2,476	16	2,614	17	2,586	17
Industrial	7,174	47	7,206	45	7,103	46
Other	269	2	275	2	268	1
	15,356	100%	15,859	100%	15,567	100%
Northern Powergrid (Yorkshire) plc:						
Residential	7,885	35%	8,250	36%	8,153	36%
Commercial	3,475	15	3,585	16	3,611	16
Industrial	10,948	48	10,938	47	10,570	47
Other	317	2	321	1	308	1
	22,625	100%	23,094	100%	22,642	100%
Total electricity distributed	37,981		38,953		38,209	
Number of end-users (in millions):						
Northern Powergrid (Northeast) Limited	1.6		1.6		1.6	
Northern Powergrid (Yorkshire) plc	2.3		2.2		2.2	
	3.9		3.8		3.8	

As of December 31, 2011, the Distribution Companies' combined electricity distribution network included 18,000 miles of overhead lines, 40,000 miles of underground cables and 700 major substations.

MidAmerican Renewables

The subsidiaries comprising the MidAmerican Renewables reportable segment own interests in 15 independent power projects in the United States and one independent power project in the Philippines. The following table presents certain information concerning these independent power projects as of December 31, 2011:

	Location	Energy Source	Installed	Power Purchase Agreement Expiration	Power Purchaser(1)	Facility Net or Contract Capacity (MW)(2)	Net Owned Capacity (MW)(2)
NATURAL GAS:							
Saranac	New York	Natural Gas	1994	2013	EDF	240	90
Power Resources	Texas	Natural Gas	1988	2012	EDF	212	106
Yuma	Arizona	Natural Gas	1994	2024	SDG&E	50	25
Cordova	Illinois	Natural Gas	2001	2019	CECG	537	537
						1,039	758
GEOTHERMAL:							
Imperial Valley Projects	California	Geothermal	1982-2000	(3)	(3)	327	164
HYDROELECTRIC:							
Casecnan Project(4)	Philippines	Hydroelectric	2001	2021	NIA	150	128
Wailuku	Hawaii	Hydroelectric	1993	2023	HELCO	10	5
						160	133
Total Available Generating Capacity						1,526	1,055

(1) EDF Trading North America LLC ("EDF"); San Diego Gas & Electric Company ("SDG&E"); Constellation Energy Commodities Group, Inc. ("CECG"); the Philippine National Irrigation Administration ("NIA"); and Hawaii Electric Light Company, Inc. ("HELCO").

(2) Facility Net or Contract Capacity represents total plant accredited net generating capacity from the summer of 2011 as approved by MAPP for Cordova and contract capacity for most other projects. Net Owned Capacity indicates the Company's ownership of the Facility Net or Contract Capacity.

(3) 82% of the Company's interests in the Imperial Valley Projects' Contract Capacity are sold to Southern California Edison Company under long-term power purchase agreements expiring in 2016 through 2026.

(4) Under the terms of the agreement with the NIA, the Company will own and operate the Casecnan project for a 20-year cooperation period which ends December 11, 2021, after which ownership and operation of the project will be transferred to the NIA at no cost on an "as-is" basis. NIA also pays the Company for delivery of water pursuant to the agreement.

In January 2012, MEHC, through a wholly-owned subsidiary, acquired Topaz and its 550-MW Topaz Project in California from a subsidiary of First Solar, Inc. ("First Solar"). The Topaz Project is expected to cost approximately $2.44 billion, including all interest during construction, and will be completed in 22 blocks with an aggregate tested capacity of 586 MW. The Topaz Project expects to place 45 MW in service in 2012, 236 MW in service in 2013, 252 MW in service in 2014 and 53 MW in service in 2015. The Topaz Project is being constructed pursuant to a fixed price, date certain, turn-key engineering procurement and construction contract with a subsidiary of First Solar. Topaz will sell all the electricity, renewable energy credits and other environmental attributes produced by the project to Pacific Gas and Electric Company ("PG&E") pursuant to a 25 year power purchase agreement. A subsidiary of First Solar will operate and maintain the project under a 25 year, fixed-fee operating and maintenance agreement.

In January 2012, MEHC, through a wholly-owned subsidiary, acquired from NRG Energy, Inc. a 49 percent interest in Agua Caliente Solar, LLC ("Agua Caliente"), the owner of a 290-MW solar project (the "Agua Caliente Project") in Arizona. The Agua Caliente Project is expected to cost approximately $1.8 billion and will be completed in 12 blocks with an aggregate tested capacity of 310 MW. The first 30-MW block of the Agua Caliente Project was placed in service in January 2012 and the Agua Caliente Project expects to place 112 additional MW in service in 2012, 136 MW in service in 2013 and 32 MW in service in 2014. The project is being constructed pursuant to a fixed price, date certain, turn-key engineering, procurement and construction contract with a subsidiary of First Solar. Agua Caliente will sell all the electricity, renewable energy credits and other environmental attributes produced by the project to PG&E pursuant to a 25 year power purchase agreement. A subsidiary of First Solar will operate and maintain the project under a 25 year, fixed-fee operating and maintenance agreement.

In December 2011, MEHC, through a wholly-owned subsidiary, signed definitive agreements to acquire the 81-MW Bishop Hill II wind-powered generation project (the "Bishop Hill II Project") in Illinois. The Bishop Hill II Project is expected to be placed in service in 2012. Once completed, the Bishop Hill II Project will sell all of its generation to Ameren Illinois Company pursuant to a 20-year power purchase agreement. Subject to certain closing conditions, the acquisition is expected to close in March 2012.

HomeServices

HomeServices, a majority-owned subsidiary of MEHC, is the second largest full-service residential real estate brokerage firm in the United States. In addition to providing traditional residential real estate brokerage services, HomeServices offers other integrated real estate services, including mortgage originations through a joint venture; title and closing services; property and casualty insurance; home warranties; relocation services; and other home-related services. HomeServices' real estate brokerage business is subject to seasonal fluctuations because more home sale transactions tend to close during the second and third quarters of the year. As a result, HomeServices' operating results and profitability are typically higher in the second and third quarters relative to the remainder of the year. HomeServices currently operates in nearly 300 brokerage offices in 20 states with over 14,000 sales associates under 22 brand names. The United States residential real estate brokerage business is subject to the general real estate market conditions, is highly competitive and consists of numerous local brokers and agents in each market seeking to represent sellers and buyers in residential real estate transactions.

Other Investments

Electric Transmission Joint Ventures

In December 2007, approval was received from the Public Utility Commission of Texas ("PUCT") to establish ETT, a company owned equally by subsidiaries of American Electric Power Company, Inc. ("AEP") and MEHC, to own and operate electric transmission assets in the ERCOT footprint. The PUCT order also approved initial rates based on a 9.96% after tax rate of return on equity and a debt to equity capital structure of 60:40. Presently, ETT has approximately $1.5 billion of Competitive Renewable Energy Zones ("CREZ") projects forecast for completion between 2012 and 2013. Additionally, AEP subsidiaries have transferred to ETT the obligation to build approximately $1.7 billion of transmission projects within ERCOT which, if approved, are forecast for completion between 2012 and 2021. Through December 31, 2011, $1.1 billion has been spent, of which $617 million has been placed in service. ETT's transmission system included 445 miles of transmission lines and 19 substations as of December 31, 2011.

Electric Transmission America, LLC ("ETA"), is a company owned equally by subsidiaries of AEP and MEHC to pursue transmission opportunities outside of ERCOT. ETA has a joint venture with Westar Energy, Inc. ("Prairie Wind Transmission, LLC") to build and own new electric transmission assets within the SPP. The Prairie Wind Transmission, LLC transmission project in Kansas is expected to begin construction in 2012 and has received the necessary approvals from the FERC, including a return on equity, inclusive of incentives, of 12.8%. ETA also has interests in other transmission projects currently in development in the SPP, MISO and the PJM Interconnection.

Natural Gas Storage Joint Venture

In January 2011, approval was received from the Regulatory Commission of Alaska ("RCA") authorizing Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA"), a wholly-owned subsidiary of Alaska Storage Holdings Company, LLC ("ASHC"), to own, construct and operate an underground natural gas storage facility in south central Alaska. ASHC is owned 65% by ENSTAR Natural Gas Company, an indirect wholly-owned subsidiary of SEMCO ENERGY, Inc., 26.5% by Alaska Gas Transmission Company, LLC, an indirect wholly-owned subsidiary of MEHC and 8.5% by other minority partners. CINGSA's gas storage facility will include a natural gas reservoir, five injection/withdrawal wells and associated piping allowing for an initial working gas capacity of 11 Bcf and the ability to deliver gas up to 0.15 Bcf per day. The facility is expected to be in-service by the summer of 2012 at an estimated cost of $180 million. The RCA order also approved the inception rates and terms of service. CINGSA has contracted to provide service to four customers for 20 years.

Employees

As of December 31, 2011, the Company had approximately 15,800 employees, of which approximately 7,300 are covered by union contracts. The majority of the union employees are employed by the Utilities and are represented by the International Brotherhood of Electrical Workers, the Utility Workers Union of America, the International Brotherhood of Boilermakers and the United Mine Workers of America. These collective bargaining agreements have expiration dates ranging through September 2018. HomeServices' sales associates are independent contractors and not employees.

General Regulation

MEHC's subsidiaries are subject to comprehensive governmental regulation, which significantly influences their operating environment, prices charged to customers, capital structure, costs and their ability to recover costs. In addition to the following discussion, refer to "Regulatory Matters" in Item 7 of this Form 10-K.

Domestic Regulated Public Utility Subsidiaries

The Utilities are subject to comprehensive regulation by various federal, state and local agencies. The more significant aspects of this regulatory framework are described below.

State Regulation

Historically, state regulatory commissions have established retail electric and natural gas rates on a cost-of-service basis, which are designed to allow a utility an opportunity to recover what state regulatory commissions deem to be the utility's reasonable costs of providing services, including a fair opportunity to earn a reasonable return on its investments. A utility's cost of service generally reflects its allowed operating expenses, including cost of sales; operation and maintenance expense; depreciation expense; and income and other tax expense, reduced by wholesale electricity sales and other revenue. The allowed operating expenses are typically based on estimates of normalized costs, which may differ from realized costs in a given year covered by the established rates. State regulatory commissions may adjust rates pursuant to a review of (a) the utility's revenue and expenses during a defined test period, (b) the utility's level of investment, or (c) for other reasons. State regulatory commissions typically have the authority to review and change rates on their own initiative; however, they may also initiate reviews at the request of a utility, utility customer, a governmental agency or a representative of a group of customers. The utility and such parties, however, may agree with one another not to request a review of or changes to rates for a specified period of time.

The retail electric rates of the Utilities are generally based on the cost of providing traditional bundled services, including generation, transmission and distribution services. PacifiCorp has established power cost adjustment mechanisms and other cost recovery mechanisms in certain states, which helps mitigate its exposure to changes in costs from those assumed in establishing base rates. As discussed below, MidAmerican Energy is seeking approval from the IUB to implement two adjustment clauses to recover certain anticipated increases in retail coal and coal transportation costs and environmental control expenditures.

Except for Oregon, Washington and Illinois, the Utilities have an exclusive right to serve retail customers within their service territories, and in turn, have an obligation to provide service to those customers. Under Oregon law, PacifiCorp has the exclusive right and obligation to provide electricity distribution services to all customers within its allocated service territory; however, nonresidential customers have the right to choose alternative electricity service suppliers. The impact of this right on the Company's consolidated financial results has not been material. In Washington, state law does not provide for exclusive service territory allocation. PacifiCorp's service territory in Washington is surrounded by other public utilities with whom PacifiCorp has from time to time entered into service area agreements under the jurisdiction of the WUTC. In Illinois, state law has established a competitive environment so that all Illinois customers are free to choose their service supplier. MidAmerican Energy has an obligation to serve customers at regulated cost-based rates that leave MidAmerican Energy's system, but later choose to return, as well as a continuing obligation to serve customers who have not selected a competitive electricity provider. To date, there has been no significant loss of customers in Illinois.

PacifiCorp

In addition to recovery through base rates, PacifiCorp also achieves recovery of certain costs through various adjustment mechanisms as summarized below.

State Regulator	Base Rate Test Period	Adjustment Mechanism
UPSC	Forecasted or historical with known and measurable changes(1)	EBA under which 70% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Balancing account to provide for the recovery or refund of the difference between the level of REC revenues included in base rates and actual REC revenues. Recovery mechanism for single capital investments that in total exceed 1% of existing rate base when a general rate case has occurred within the preceding 18 months.
OPUC	Forecasted	Annual TAM based on forecasted net variable power costs; no true-up to actual net variable power costs. Renewable Adjustment Clause to recover the revenue requirement of new renewable resources and associated transmission that are not reflected in general rates. Balancing account to provide for the refund of actual REC revenues.
WPSC	Forecasted or historical with known and measurable changes(1)	ECAM under which 70% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. REC and sulfur dioxide revenue adjustment mechanism to provide for recovery or refund of 100% of any difference between actual REC and sulfur dioxide revenues and the level forecasted in base rates.
WUTC	Historical with known and measurable changes	Deferral mechanism of costs for up to 24 months of new base load generation resources and eligible renewable resources and related transmission that qualify under the state's emissions performance standard and are not reflected in base rates. REC revenue tracking mechanism to provide for the refund of Washington-allocated REC revenues.
IPUC	Historical with known and measurable changes	ECAM under which 90% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Also provides for recovery or refund of 100% of the difference between the level of REC and sulfur dioxide revenues included in base rates and actual REC and sulfur dioxide revenues.
CPUC	Forecasted	PTAM for major capital additions that allows for rate adjustments outside of the context of a traditional general rate case for the revenue requirement associated with capital additions exceeding $50 million on a total-company basis. Filed as eligible capital additions are placed into service. Energy Cost Adjustment Clause that allows for an annual update to actual and forecasted net variable power costs. PTAM for attrition, a mechanism that allows for an annual adjustment to costs other than net variable power costs.

(1) PacifiCorp has relied on both historical test periods with known and measurable adjustments, as well as forecasted test periods.

Generally, PacifiCorp's DSM program costs are collected through separately established rates that are adjusted periodically based on actual and expected costs, as approved by the respective state regulatory commission. As such, DSM program activities have no impact on net income.

MidAmerican Energy

Iowa law permits rate-regulated utilities to seek ratemaking principles with the IUB prior to the construction of certain types of new generating facilities. Pursuant to this law, MidAmerican Energy has applied for and obtained IUB ratemaking principles orders for 484 MW of coal-fueled generation, 495 MW of combined cycle natural gas-fueled generation and 1,878 MW (nominal ratings) of wind-powered generation in service at December 31, 2011. The related ratemaking principles approved by the IUB have authorized, upon the establishment of new Iowa electric base rates, a fixed rate of return on equity for the generating facilities covered by each settlement agreement with interested parties, including the OCA, over the regulatory life of those facilities. As of December 31, 2011, $3.3 billion, or 42%, of property, plant and equipment, net, was subject to the agreements at a weighted average return on equity of 12.0%. Additionally, MidAmerican Energy is constructing 407 MW (nominal ratings) of wind-powered generating facilities to be placed in service in 2012 subject to an existing ratemaking principles order authorizing a fixed rate of return on equity of 12.2%. That order, which also applies to 594 MW (nominal ratings) placed in service in 2011, was appealed by an intervenor and is currently pending before the Iowa Supreme Court. Many of the IUB orders approved settlement agreements that also provided for sharing with customers revenues associated with Iowa retail electric returns on equity in excess of 11.75% and for rate freezes into the future. Under a 2009 settlement agreement, MidAmerican Energy was allowed to record revenue sharing to increase its 2011 returns on equity to 10% for the wind-powered generating facilities placed in service in 2011.

The IUB approved over the past several years a series of electric settlement agreements between MidAmerican Energy, the OCA and other intervenors under which MidAmerican Energy agreed not to seek a general increase in electric base rates to become effective prior to January 1, 2014. However, if MidAmerican Energy's Iowa jurisdictional return on equity fell below 10% for 2011 or was projected to fall below 10% for 2013, then MidAmerican Energy was permitted to seek a general increase in electric base rates to become effective in 2012 or 2013, respectively. As a party to the settlement agreements, the OCA agreed not to request or support any decrease in MidAmerican Energy's Iowa electric base rates to become effective prior to January 1, 2014. The settlement agreements specifically allowed the IUB to approve or order electric rate design or cost of service rate changes that could have resulted in changes to rates for specific customers as long as such changes did not result in an overall increase in revenue for MidAmerican Energy.

MidAmerican Energy's actual Iowa jurisdictional return on equity for 2011 was below 10%. Accordingly, on February 21, 2012, MidAmerican Energy filed an application with the IUB for an interim and final increase in Iowa retail electric rates in the form of two adjustment clauses to be added to customers' bills. The requested adjustment clauses and a modification to current revenue sharing provisions are consistent with a November 2011 settlement agreement between MidAmerican Energy and the OCA, in which the parties agree to support the proposed changes. The adjustment clauses would recover anticipated increases in retail coal and coal transportation costs and environmental control expenditures subject to an aggregate maximum of $39 million, or 3.4%, for 2012 and an additional $37 million for an aggregate maximum of $76 million for 2013, or a 3.2% increase from 2012. The requested modification to the existing revenue sharing provisions provides for MidAmerican Energy to share with its customers 20% of revenue associated with Iowa electric returns on equity between 10% and 10.5%, 50% of revenue associated with Iowa electric returns on equity between 10.5% and 11.75%, 75% of revenue associated with Iowa electric returns on equity between 11.75% and 13.0% and 83.3% of revenue associated with Iowa electric returns on equity above 13.0%. Such shared amounts would reduce MidAmerican Energy's investment in the Walter Scott, Jr. Energy Center Unit 4. There would be no revenue sharing for Iowa electric returns on equity below 10%. Pursuant to the settlement agreement, MidAmerican Energy is not precluded from seeking interim rate relief in 2013.

MidAmerican Energy is exposed to fluctuations in electric energy costs relating to retail sales in Iowa and Illinois as it does not have energy cost adjustment mechanisms through which fluctuations in electric energy costs can be recovered in those jurisdictions. Upon implementation of the adjustment clauses, subject to the aggregate maximums, discussed above, MidAmerican Energy will be able to mitigate a portion of its exposure to fluctuating electric energy costs in Iowa. Beginning November 2011, MidAmerican Energy is allowed to petition for implementation of a fuel adjustment clause in Illinois. MidAmerican Energy's cost of gas is collected for each jurisdiction in its gas rates through a uniform PGA, which is updated monthly to reflect changes in actual costs. Subject to prudence reviews, the PGA accomplishes a pass-through of MidAmerican Energy's cost of gas to its customers and, accordingly, has no direct effect on net income. MidAmerican Energy's DSM program costs are collected through separately established rates that are adjusted annually based on actual and expected costs, as approved by the respective state regulatory commission. As such, recovery of DSM program costs has no impact on net income.

MidAmerican Energy has begun preliminary investigation into possible development of a nuclear generation facility. In support of such investigatory activities, Iowa law authorizes recovery of approximately $15 million over three years beginning in October 2010 from MidAmerican Energy's Iowa customers for the cost of this effort, subject to the review of the IUB. MidAmerican Energy has not entered into any material commitments with regard to nuclear facility development.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act, the Natural Gas Act ("NGA"), the Energy Policy Act of 2005 ("Energy Policy Act") and other federal statutes. The FERC regulates rates for wholesale sales of electricity; transmission of electricity, including pricing and regional planning for the expansion of transmission systems; electric system reliability; utility holding companies; accounting; securities issuances; and other matters, including construction and operation of hydroelectric facilities. The FERC also has the enforcement authority to assess civil penalties of up to $1 million per day per violation of rules, regulations and orders issued under the Federal Power Act. The Utilities have implemented programs that facilitate compliance with the FERC regulations described below, including having instituted compliance monitoring procedures. MidAmerican Energy is also subject to regulation by the NRC pursuant to the Atomic Energy Act of 1954, as amended ("Atomic Energy Act"), with respect to its ownership of Quad Cities Station.

Wholesale Electricity and Capacity

The FERC regulates the Utilities' rates charged to wholesale customers for electricity and transmission capacity and related services. Most of the Utilities' wholesale electricity sales and purchases occur under market-based pricing allowed by the FERC and are therefore subject to market volatility.

The Utilities are currently authorized by the FERC to sell electricity in wholesale electricity markets at market-based rates and are subject to triennial reviews conducted by the FERC. During such reviews, the Utilities each must demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in their respective market areas. PacifiCorp's most recent triennial filing was made in June 2010. In June 2011, the FERC issued an order finding that PacifiCorp's submittals satisfied the FERC's requirements for market-based rate authority. MidAmerican Energy's most recent triennial filings were submitted in June 2011 for the FERC-defined Northeast Region and November 2011 for the FERC-defined Central Region. In February 2012, the FERC issued an order finding that MidAmerican Energy's June 2011 submittal satisfied the FERC's requirements for market-based rate authority. The November 2011 submission is currently pending before the FERC. Under the FERC's market-based rules, the Utilities must also file with the FERC a notice of change in status when there is a significant change in the conditions that the FERC relied upon in granting market-based pricing authority.

Transmission

PacifiCorp's wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's Open Access Transmission Tariff ("OATT"). These services are offered on a non-discriminatory basis, which means that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC's Standards of Conduct. PacifiCorp has made several required compliance filings in accordance with these rules.

In December 2011, PacifiCorp adopted a cost-based formula rate under its OATT for its transmission services. Cost-based formula rates are intended to be an effective means of recovering PacifiCorp's investments and associated costs of its transmission system without the need to file rate cases with the FERC, although the rates are subject to legal challenges at the FERC. A significant portion of these services are provided to PacifiCorp's commercial and trading function.

Effective September 1, 2009, MidAmerican Energy turned over functional control of its transmission system to the MISO as a transmission-owning member, as approved by the FERC. Accordingly, the MISO is now the transmission provider under its FERC-approved OATT. While the MISO is responsible for directing the operation of MidAmerican Energy's transmission system, MidAmerican Energy retains ownership of its transmission assets and, therefore, is subject to the FERC's reliability standards discussed below. MidAmerican Energy's transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC Standards of Conduct.

The FERC has established an extensive number of reliability standards developed by the North American Electric Reliability Corporation ("NERC") and the WECC, including critical infrastructure protection standards and regional standard variations. The Utilities must comply with all applicable standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC, the NERC and WECC for PacifiCorp and the Midwest Reliability Organization ("MRO") for MidAmerican Energy. In 2007, the WECC audited PacifiCorp's compliance with several of the approved reliability standards, and in November 2008, the FERC assumed control of certain aspects of the WECC's audit. The aspects of the 2007 audit not under the FERC's authority are closed as a result of PacifiCorp's July 2009 settlement with the WECC, which did not have a material impact on the Company's consolidated financial results.

Hydroelectric Relicensing

PacifiCorp's Klamath River hydroelectric system is the only significant hydroelectric system for which PacifiCorp is currently engaged in the relicensing process with the FERC. PacifiCorp also has requested the FERC to allow decommissioning of certain hydroelectric systems. Most of PacifiCorp's hydroelectric generating facilities are licensed by the FERC as major systems under the Federal Power Act, and certain of these systems are licensed under the Oregon Hydroelectric Act. Refer to Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for an update regarding hydroelectric relicensing for PacifiCorp's Klamath River hydroelectric system.

Nuclear Regulatory Commission

MidAmerican Energy is subject to the jurisdiction of the NRC with respect to its license and 25% ownership interest in Quad Cities Station. Exelon Generation, the operator and 75% owner of Quad Cities Station, is under contract with MidAmerican Energy to secure and keep in effect all necessary NRC licenses and authorizations.

The NRC regulates the granting of permits and licenses for the construction and operation of nuclear generating stations and regularly inspects such stations for compliance with applicable laws, regulations and license terms. Current licenses for Quad Cities Station provide for operation until December 14, 2032. The NRC review and regulatory process covers, among other things, operations, maintenance, and environmental and radiological aspects of such stations. The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of such licenses. Following the March 2011 earthquake and tsunami in Japan that severely damaged the Fukushima Daiichi nuclear generating facility, the NRC launched a review of the incident to determine any issues that may be applicable to the nuclear industry in the United States. The impact of the NRC's review cannot be predicted but could result in higher operations and maintenance expense, higher capital costs or extended outages at Quad Cities Station.

Federal regulations provide that any nuclear operating facility may be required to cease operation if the NRC determines there are deficiencies in state, local or utility emergency preparedness plans relating to such facility, and the deficiencies are not corrected. Exelon Generation has advised MidAmerican Energy that an emergency preparedness plan for Quad Cities Station has been approved by the NRC. Exelon Generation has also advised MidAmerican Energy that state and local plans relating to Quad Cities Station have been approved by the Federal Emergency Management Agency.

MidAmerican Energy maintains financial protection against catastrophic loss associated with its interest in Quad Cities Station through a combination of insurance purchased by Exelon Generation (the operator and joint owner of Quad Cities Station), insurance purchased directly by MidAmerican Energy, and the mandatory industry-wide loss funding mechanism afforded under the Price-Anderson Amendments Act of 1988, which was amended and extended by the Energy Policy Act of 2005. The general types of coverage are: nuclear liability, property damage or loss and nuclear worker liability.

United States Mine Safety

PacifiCorp's mining operations are regulated by the Federal Mine Safety and Health Administration, which administers federal mine safety and health laws and regulations, and state regulatory agencies. The Federal Mine Safety and Health Administration has the statutory authority to institute a civil action for relief, including a temporary or permanent injunction, restraining order or other appropriate order against a mine operator who fails to pay penalties or fines for violations of federal mine safety standards. Federal law requires PacifiCorp to have a written emergency response plan specific to each underground mine it operates, which is reviewed by the Federal Mine Safety and Health Administration every six months, and to have at least two rescue teams located within one hour of each mine. Information regarding PacifiCorp's mine safety violations and other legal matters disclosed in accordance with Section 1503(a) of the Dodd-Frank Reform Act is included in Exhibit 95 to this Form 10-K.

Interstate Natural Gas Pipeline Subsidiaries

The Pipeline Companies are regulated by the FERC, which administers, most significantly, the NGA and the Natural Gas Policy Act of 1978. Under this authority, the FERC regulates, among other items, (a) rates, charges, terms and conditions of service and (b) the construction and operation of interstate pipelines, storage and related facilities, including the extension, expansion or abandonment of such facilities. The Pipeline Companies hold certificates of public convenience and necessity issued by the FERC, which authorizes them to construct, operate and maintain their pipeline and related facilities and services.

FERC regulations and the Pipeline Companies' tariffs allow each of the Pipeline Companies to charge approved rates for the services set forth in their respective tariff. These rates are a function of the cost of providing services to their customers, including operations and maintenance costs, taxes, interest, depreciation and amortization and an opportunity to earn a reasonable return on its investments. Both Northern Natural Gas' and Kern River's tariff rates have been developed under a rate design methodology whereby substantially all fixed costs, including a return on invested capital and income taxes, are collected through reservation charges, which are paid by firm transportation and storage customers regardless of volumes shipped. Commodity charges, which are paid only with respect to volumes actually shipped, are designed to recover the remaining, primarily variable, cost. Kern River's reservation rates have historically been approved using a "levelized" cost-of-service methodology so that the rate remains constant over the levelization period. This levelized cost of service has been achieved by using a FERC-approved depreciation schedule in which depreciation increases as interest expense and return on equity amounts decrease. Both Northern Natural Gas' and Kern River's rates are subject to change in future general rate proceedings.

Natural gas transportation companies may not grant any undue preference to any customer. FERC regulations also restrict each pipeline's marketing affiliates' access to certain non-public information regarding their affiliated interstate natural gas transmission pipelines.

Interstate natural gas pipelines are also subject to regulations by a federal agency within the United States Department of Transportation ("DOT"), pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), the Pipeline Safety Improvement Act of 2002 ("2002 Act"), the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 ("2006 Act") and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Act").

The NGPSA establishes safety requirements in the design, construction, operation and maintenance of interstate natural gas facilities. The NGPSA also requires an entity that owns or operates pipeline facilities to comply with applicable safety standards, to establish and keep current inspection and maintenance plans and to comply with such plans. The Pipeline Companies conduct internal audits of their facilities every four years; with more frequent reviews of those deemed higher risk. The DOT routinely audits and inspects the pipeline facilities for compliance with its regulations. Compliance issues that arise during these audits or during the normal course of business are addressed on a timely basis. The Pipeline Companies believe that their respective pipeline systems comply in all material respects with the NGPSA and with DOT regulations issued pursuant to the NGPSA.

The 2002 Act and the 2006 Act further amended the NGPSA and established additional safety and pipeline integrity regulations for all natural gas pipelines in high-consequence areas. The 2002 Act imposed major new requirements in the areas of operator qualifications, risk analysis and integrity management. The 2002 Act requires more frequent periodic inspection or testing of natural gas pipelines in areas where the potential consequences of a natural gas pipeline accident may be significant or may do considerable harm to persons or property, which are referred to as high consequence areas. Pursuant to the 2002 Act, the DOT promulgated new regulations that require natural gas pipeline operators to develop comprehensive integrity management programs, to identify applicable threats to natural gas pipeline segments that could impact high consequence areas, to assess these segments, and to provide ongoing mitigation and monitoring. The regulations require that all baseline high consequence area segments be assessed by December 17, 2012 and require recurring inspections every seven years thereafter. The Pipeline Companies have completed the required high consequence area line pipe baseline integrity assessments and will complete other associated assessments in 2012. Kern River also completed the required in-line inspections in early 2011 on that portion of its pipeline system required by the conditions associated with a special permit which allowed for an increase to the maximum allowable operating pressure.

The 2006 Act required pipeline operators to institute human factors management plans for personnel employed in pipeline control centers. DOT regulations published pursuant to the 2006 Act required development of written control room management procedures no later than August 2011, and implementation of the procedures no later than February 1, 2013. The implementation date was subsequently accelerated to August 2011 for many of the control room management program elements as many required little implementation time once the program and procedures were written. Some elements, including alarm management, required more time to implement and these aspects of the program have a required implementation date of August 2012. The Pipeline Companies met the August 2011 deadline for the applicable parts of the program and are taking the necessary steps to ensure compliance with all aspects of the 2006 Act requirements by the established dates.

As a result of recent natural gas pipeline incidents, most notably the San Bruno natural gas pipeline explosion that occurred in September 2010 in California, the DOT issued an Advanced Notice of Proposed Rule Making in August 2011, and additionally in January 2012, the President signed the 2011 Act. The new natural gas pipeline safety legislation and the rulemaking measure strengthen the DOT's ability to regulate interstate natural gas pipeline companies, increase the maximum allowable civil penalties for violations, and impose additional natural gas pipeline integrity requirements on the transmission pipeline industry. While the general requirements of the new legislation are known, the DOT is now developing the new rules and regulations. The full extent of the new regulations under development and the cost of compliance are not fully known at this time.

United Kingdom Electricity Distribution Companies

The Distribution Companies, as holders of electricity distribution licenses, are subject to regulation by the GEMA. GEMA discharges certain of its powers through its staff within Ofgem. Each of fourteen licensed distribution network operators ("DNOs") distributes electricity from the national grid system to end users within their respective distribution service areas.

DNOs are subject to price controls, enforced by Ofgem, that limit the revenue that may be recovered and retained from their electricity distribution activities. The regulatory regime that has been applied to electricity distributors in the United Kingdom encourages companies to look for efficiency gains in order to improve profits. The distribution price control formula also adjusts the revenue received by DNOs to reflect a number of factors, including, but not limited to, the rate of inflation (as measured by the retail price index), the quality of service delivered by the licensee's distribution system and system losses (i.e., the difference between the number of units entering and leaving the licensee's system). Currently, price controls are established every five years, although the formula has been, and may be, reviewed at the regulator's discretion. Ofgem has indicated that future price controls are likely to be set for a period of eight or nine years, with the potential for a mid-period review if the outputs required of a licensee have changed. The procedure and methodology adopted at a price control review are at the reasonable discretion of Ofgem. Historically, Ofgem's judgment of the future allowed revenue of licensees has been based upon, among other things:

- actual operating costs of each of the licensees;
- pension deficiency payments of each of the licensees;
- operating costs which each of the licensees would incur if it were as efficient as, in Ofgem's judgment, the more efficient licensees;
- taxes that each licensee is expected to pay;
- regulatory value ascribed to and the allowance for depreciation related to the distribution network assets;
- rate of return to be allowed on investment in the distribution network assets by all licensees; and
- financial ratios of each of the licensees and the license requirement for each licensee to maintain investment grade status.

The current electricity distribution price control became effective April 1, 2010 and is expected to continue through March 31, 2015. A resetting of the formula can now be made by GEMA without the consent of the DNO, but if a licensee wishes to appeal such a modification, the licensee may insist that the matter is referred to the UK's Competition Commission for it to determine whether the modification should be made. Certain other interested parties also have the same right. The Distribution Companies each agreed to Ofgem's proposals for the resetting of the formula that commenced April 1, 2010.

A number of incentive schemes also operate within the current price control period to encourage DNOs to provide an appropriate quality of service to end users with specified payments to be made for failures to meet prescribed standards of service. The aggregate of these guaranteed standards payments is uncapped, but may be excused in certain prescribed circumstances that are generally beyond the control of the DNO.

The most recent price control review conducted by Ofgem led to an increase in allowed revenue for the Distribution Companies. As a result, excluding the effects of incentive schemes, it is expected the base allowed revenue of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc will be permitted to increase by approximately 7.7% and 6.5%, respectively, plus inflation (as measured by the United Kingdom's Retail Prices Index) in each of the five regulatory years that commenced April 1, 2010.

Ofgem also monitors DNO compliance with license conditions and enforces the remedies resulting from any breach of condition. License conditions include the prices and terms of service, financial strength of the DNO, the provision of information to Ofgem and the public, as well as maintaining transparency, non-discrimination and avoidance of cross-subsidy in the provision of such services. Ofgem also monitors and enforces certain duties of a DNO set out in the Electricity Act of 1989 including the duty to develop and maintain an efficient, coordinated and economical system of electricity distribution. Under the Utilities Act 2000, the regulators are able to impose financial penalties on DNOs who contravene any of their license duties or certain of their duties under the Electricity Act 1989, as amended, or who are failing to achieve a satisfactory performance in relation to the individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the licensee's revenue.

Independent Power Projects

Foreign

The Philippine Congress has passed the Electric Power Industry Reform Act of 2001 ("EPIRA"), which is aimed at restructuring the Philippine power industry, privatizing the National Power Corporation and introducing a competitive electricity market, among other initiatives. The implementation of EPIRA may impact the Company's future operations in the Philippines and the Philippine power industry as a whole, the effect of which is not yet known as changes resulting from EPIRA are ongoing.

Domestic

The Cordova, Saranac, Power Resources and Agua Caliente independent power projects are Exempt Wholesale Generators ("EWG") under the Energy Policy Act while the Yuma, Imperial Valley and Wailuku independent power projects are currently certified as Qualifying Facilities ("QF") under the Public Utility Regulatory Policies Act of 1978. Both EWGs and QFs are generally exempt from compliance with extensive federal and state regulations that control the financial structure of an electric generating plant and the prices and terms at which electricity may be sold by the facilities. In addition, the Cordova, Saranac, Power Resources and Yuma independent power projects have obtained authority from the FERC to sell their power using market-based rates.

EWGs are permitted to sell capacity and electricity only in the wholesale markets, not to end users. Additionally, utilities are required to purchase electricity produced by QFs at a price that does not exceed the purchasing utility's "avoided cost" and to sell back-up power to the QFs on a non-discriminatory basis, unless they have successfully petitioned the FERC for an exemption from this purchase requirement. Avoided cost is defined generally as the price at which the utility could purchase or produce the same amount of power from sources other than the QF on a long-term basis. The Energy Policy Act eliminated the purchase requirement for utilities with respect to new contracts under certain conditions. New QF contracts are also subject to FERC rate filing requirements, unlike QF contracts entered into prior to the Energy Policy Act. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates other than the utilities' avoided cost.

Residential Real Estate Brokerage Company

HomeServices is regulated by the United States Department of Housing and Urban Development ("HUD"), most significantly under the Real Estate Settlement Procedures Act ("RESPA"), and by state agencies where it operates. RESPA primarily governs the real estate settlement process by mandating all parties fully inform borrowers about all closing costs, lender servicing and escrow account practices, and business relationships between closing service providers and other parties to the transaction. In addition, certain provisions of the Dodd-Frank Reform Act, enacted in July 2010 and effective in July 2011, require real estate mortgage lenders to verify a borrower's ability to repay the underlying loan, which can be achieved within the context of a safe harbor if the mortgage is a "qualifying" mortgage that satisfies specific statutory criteria and the costs of the loan to the borrower do not exceed a mandated threshold percentage. In implementing these provisions, HomeServices and its affiliates incurred additional legal and regulatory compliance costs.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, RPS, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company's current and future operations. In addition to imposing continuing compliance obligations and capital expenditure requirements, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state, local and international agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and the Company is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. The Company believes it is in material compliance with all applicable laws and regulations.

Refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for the Company's forecasted environmental-related capital expenditures.

Item 1A. Risk Factors

We and our subsidiaries are subject to certain risks and uncertainties in our business operations, including, but not limited to, those described below. Careful consideration of these risks, together with all of the other information included in this Form 10-K and the other public information filed by us, should be made before making an investment decision. Additional risks and uncertainties not presently known or that are currently deemed immaterial may also impair our business operations.

Our Corporate and Financial Structure Risks

We are a holding company and depend on distributions from subsidiaries, including joint ventures, to meet our obligations.

We are a holding company with no material assets other than the ownership interests in our subsidiaries and joint ventures, collectively referred to as our subsidiaries. Accordingly, cash flows and the ability to meet our obligations are largely dependent upon the earnings of our subsidiaries and the payment of such earnings to us in the form of dividends or other distributions. Our subsidiaries are separate and distinct legal entities that do not guarantee the payment of any of our obligations or have an obligation, contingent or otherwise, to pay directly, or to make funds available for the payment of, amounts due pursuant to our senior and subordinated debt or our other obligations. Distributions from subsidiaries may also be limited by:

- their respective earnings, capital requirements, and required debt and preferred stock payments;
- the satisfaction of certain terms contained in financing, ring-fencing or organizational documents; and
- regulatory restrictions that limit the ability of our regulated utility subsidiaries to distribute profits.

We are substantially leveraged, the terms of our senior and subordinated debt do not restrict the incurrence of additional debt by us or our subsidiaries, and our senior and subordinated debt are structurally subordinated to the debt of our subsidiaries, each of which could adversely affect our consolidated financial results.

A significant portion of our capital structure is comprised of debt, and we expect to incur additional debt in the future to fund acquisitions, capital investments or the development and construction of new or expanded facilities at our subsidiaries. As of December 31, 2011, we had the following outstanding obligations:

- senior unsecured debt of $5.363 billion;
- subordinated debt of $22 million, which is held by Berkshire Hathaway and its affiliates; and
- guarantees and letters of credit in respect of subsidiary and equity method investment debt aggregating $90 million.

Our consolidated subsidiaries also have significant amounts of outstanding debt, which totaled $13.687 billion as of December 31, 2011. These amounts exclude (a) trade debt, (b) preferred stock obligations, (c) letters of credit in respect of subsidiary debt, and (d) our share of the outstanding debt of our own or our subsidiaries' equity method investments.

Given our substantial leverage, we may not have sufficient cash to service our debt, which could limit our ability to finance future acquisitions, develop and construct additional projects, or operate successfully under adverse conditions, including those brought on by declining national and global economies, unfavorable financial markets or growth conditions where our capital needs may exceed our ability to fund them. Our leverage could also impair our credit quality or the credit quality of our subsidiaries, making it more difficult to finance operations or issue future debt on favorable terms, and could result in a downgrade in debt ratings by credit rating agencies.

The terms of our senior and subordinated debt do not limit our ability or the ability of our subsidiaries to incur additional debt or issue preferred stock. Accordingly, we or our subsidiaries could enter into acquisitions, new financings, refinancings, recapitalizations, capital leases or other highly leveraged transactions that could significantly increase our or our subsidiaries' total amount of outstanding debt. The interest payments needed to service this increased level of debt could adversely affect our consolidated financial results. Many of our subsidiaries' debt agreements contain covenants, or may in the future contain covenants, that restrict or limit, among other things, such subsidiaries' ability to create liens, sell assets, make certain distributions, incur additional debt or miss contractual deadlines or requirements, and our ability to comply with these covenants may be affected by events beyond our control. Further, if an event of default accelerates a repayment obligation and such acceleration results in an event of default under some or all of our other debt, we may not have sufficient funds to repay all of the accelerated debt, and the other risks described under "Our Corporate and Financial Structure Risks" may be magnified as well.

Because we are a holding company, the claims of our senior and subordinated debt holders are structurally subordinated with respect to the assets and earnings of our subsidiaries. Therefore, the rights of our creditors to participate in the assets of any subsidiary in the event of a liquidation or reorganization are subject to the prior claims of the subsidiary's creditors and preferred shareholders. In addition, a significant amount of the stock or assets of our operating subsidiaries is directly or indirectly pledged to secure their financings and, therefore, may be unavailable as potential sources of repayment of our senior and subordinated debt.

A downgrade in our credit ratings or the credit ratings of our subsidiaries could negatively affect our or our subsidiaries' access to capital, increase the cost of borrowing or raise energy transaction credit support requirements.

Our senior unsecured debt is rated by various rating agencies. We cannot assure that our senior unsecured debt rating will not be reduced in the future. Although none of our outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase our borrowing costs and commitment fees on our revolving credit agreements and other financing arrangements, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market, the principal source of short-term borrowings, could be significantly limited, resulting in higher interest costs.

Similarly, any downgrade or other event negatively affecting the credit ratings of our subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could cause us to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing our and our subsidiaries' liquidity and borrowing capacity.

Most of our subsidiaries' large wholesale customers, suppliers and counterparties require our subsidiaries to have sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If the credit ratings of our subsidiaries were to decline, especially below investment grade, financing costs and borrowings would likely increase because certain counterparties may require collateral in the form of cash, a letter of credit or some other security for existing transactions and as a condition to entering into transactions with our subsidiaries. Such amounts may be material and may adversely affect our subsidiaries' liquidity and cash flows.

Our majority shareholder, Berkshire Hathaway, could exercise control over us in a manner that would benefit Berkshire Hathaway to the detriment of our creditors.

Berkshire Hathaway is our majority owner and has control over all decisions requiring shareholder approval, including the election of our directors. In circumstances involving a conflict of interest between Berkshire Hathaway and our creditors, Berkshire Hathaway could exercise its control in a manner that would benefit Berkshire Hathaway to the detriment of our creditors.

Our Business Risks

Much of our growth has been achieved through acquisitions, and additional acquisitions may not be successful.

Much of our growth has been achieved through acquisitions. Future acquisitions may range from buying individual assets to the purchase of entire businesses. We will continue to investigate and pursue opportunities for future acquisitions that we believe may increase shareholder value and expand or complement existing businesses. We may participate in bidding or other negotiations at any time for such acquisition opportunities which may or may not be successful. Any transaction that does take place may involve consideration in the form of cash or debt or equity securities.

Completion of any acquisition entails numerous risks, including, among others, the:

- failure to complete the transaction for various reasons, such as the inability to obtain the required regulatory approvals, materially adverse developments in the potential acquiree's business or financial condition or successful intervening offers by third parties;
- failure of the combined business to realize the expected benefits or to meet regulatory commitments; and
- need for substantial additional capital and financial investments.

An acquisition could cause an interruption of, or loss of momentum in, the activities of one or more of our businesses. The diversion of management's attention and any delays or difficulties encountered in connection with the approval and integration of the acquired operations could adversely affect our combined businesses and financial results and could impair our ability to realize the anticipated benefits of the acquisition.

We cannot assure you that future acquisitions, if any, or any related integration efforts will be successful, or that our ability to repay our obligations will not be adversely affected by any future acquisitions.

We and our businesses are subject to extensive federal, state, local and foreign legislation and regulation, including numerous environmental, health, safety and other laws and regulations that affect us and our businesses' operations and costs. These laws and regulations are complex, dynamic and subject to new interpretations or change. In addition, new laws and regulations are continually being proposed and enacted that create new or revised requirements or standards on us and our businesses.

We and our businesses are required to comply with numerous federal, state, local and foreign laws and regulations that have broad application to us and our subsidiaries and limit our ability to independently make and implement management decisions regarding, among other items, acquiring businesses; constructing, acquiring or disposing of operating assets; operating generating facilities and transmission and distribution assets; complying with pipeline safety and integrity and environmental requirements; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; transacting between subsidiaries and affiliates; and paying dividends. These laws and regulations are implemented and enforced by federal, state and local regulatory agencies, such as, among others, the FERC, the EPA, the DOT, the NRC and various state regulatory commissions in the United States, and GEMA, which discharges certain of its powers through its staff within Ofgem, in the United Kingdom. Refer to "General Regulation" and "Environmental Laws and Regulations" in Item 1 of this Form 10-K for examples of laws and regulations and other requirements significantly affecting us and our present and future operations.

Compliance with applicable laws and regulations generally requires our subsidiaries to obtain and comply with a wide variety of licenses, permits, inspections and other approvals. Further, compliance with laws and regulations can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, removal and remediation costs, damages arising out of contaminated properties and fines, penalties and injunctive measures affecting operating assets for failure to comply with environmental regulations. Compliance activities pursuant to laws and regulations could be prohibitively expensive. As a result, some facilities may be required to shut down or alter their operations. Further, our subsidiaries may not be able to obtain or maintain all required environmental or other regulatory approvals and permits for their operating assets or development projects. Delays in or active opposition by third parties to obtaining any required environmental or regulatory authorizations, failure to comply with the terms and conditions of the authorizations or enhanced regulatory or environmental requirements may increase costs or prevent or delay our subsidiaries from operating their facilities, developing new facilities, expanding existing facilities or favorably locating new facilities. If our subsidiaries fail to comply with any environmental or other regulatory requirements, they may be subject to penalties and fines or other sanctions, including changes to the way our electric generating facilities are operated or how the Pipeline Companies are permitted to operate their systems that may impact generation or throughput. The costs of complying with laws and regulations could adversely affect our consolidated financial results. Not being able to operate existing facilities or develop new generating facilities to meet customer electricity needs could require our subsidiaries to increase their purchases of electricity on the wholesale market, which could increase market and price risks and adversely affect our consolidated financial results.

Existing laws and regulations, while comprehensive, are subject to changes and revisions from ongoing policy initiatives by legislators and regulators and to interpretations that may ultimately be resolved by the courts. For example, changes in laws and regulations could result in, but are not limited to, increased competition within our subsidiaries' service territories; new environmental requirements, including the implementation of RPS and GHG emissions reduction goals; the issuance of stricter air quality standards and the implementation of energy efficiency mandates; the issuance of regulations over the management and disposal of coal combustion byproducts; changes to our subsidiaries' service territories as a result of condemnation or takeover by municipalities or other governmental entities, particularly where they lack the exclusive right to serve their customers; the inability of our subsidiaries' to recover their costs; new pipeline safety requirements; or a negative impact on our subsidiaries' current transportation and cost recovery arrangements.

In addition to changes in existing legislation and regulation, new laws and regulations are likely to be enacted that impose additional or new requirements or standards on our businesses. For example, while significant measures to regulate emissions at the federal level were considered by the United States Congress in 2010, comprehensive legislation has not been adopted; however, the EPA issued the CSAPR and MATS rules in 2011. Implementing actions required under, and otherwise complying with, new federal and state laws and regulations and changes in existing ones are among the most challenging aspects of managing utility operations. We cannot predict the future course of new laws and regulations, changes in existing ones or new interpretations by agency orders or court decisions nor can their impact on us be determined at this time; however, any one of these could adversely affect our consolidated financial results through higher capital expenditures and operating costs and cause an overall change in how we operate our businesses. To the extent that our regulated subsidiaries are not allowed by their regulators to recover or cannot otherwise recover the costs to comply with new laws and regulations or changes in existing ones, the additional requirements could have a material adverse effect on our consolidated financial results. Additionally, even if such costs are recoverable in rates, if they are substantial and result in rates increasing to levels that substantially reduce customer demand or reduce our Pipeline Companies throughput, this could have a material adverse effect on our consolidated financial results.

Recovery of costs by our regulated subsidiaries is subject to regulatory review and approval, and the inability to recover costs may adversely affect our consolidated financial results.

State Rate Proceedings

The Utilities establish rates for their regulated retail service through state regulatory proceedings. These proceedings typically involve multiple parties, including government bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns, but who generally have the common objective of limiting rate increases. Decisions are subject to appeal, potentially leading to further uncertainty associated with the approval proceedings.

Each state sets retail rates based in part upon the state regulatory commission's acceptance of an allocated share of total utility costs. When states adopt different methods to calculate interjurisdictional cost allocations, some costs may not be incorporated into rates of any state. Ratemaking is also generally done on the basis of estimates of normalized costs, so if a given year's realized costs are higher than normalized costs, rates may not be sufficient to cover those costs. In some cases, actual costs are lower than the normalized or estimated costs recovered through rates and from time-to-time may result in a state regulator requiring refunds to customers. Each state regulatory commission generally sets rates based on a test year established in accordance with that commission's policies. The test year data adopted by each state regulatory commission may create a lag between the incurrence of a cost and its recovery in rates. Each state regulatory commission also decides the allowed levels of expense and investment that they deem are just and reasonable in providing the service and may disallow recovery in rates for any costs that do not meet such standard. Additionally, each state regulatory commission establishes the allowed rate of return the Utilities will be given an opportunity to earn on their sources of capital. While rate regulation is premised on providing a fair opportunity to earn a reasonable rate of return on invested capital, the state regulatory commissions do not guarantee that we will be able to realize a reasonable rate of return.

In certain states, the Utilities are not permitted to pass through energy cost increases above the level assumed in establishing base rates without a general rate case. Any significant increase in fuel costs for electricity generation or purchased electricity costs could have a negative impact on the Utilities, despite efforts to minimize this impact through future general rate cases or the use of hedging contracts. Any of these consequences could adversely affect our consolidated financial results.

FERC Jurisdiction

The FERC establishes cost-based rates associated with transmission services provided by PacifiCorp and MidAmerican Energy's transmission facilities. Under the Federal Power Act, the Utilities may voluntarily file, or be obligated to file for changes, including general rate changes, to their system-wide transmission service rates. General rate changes implemented may be subject to refund. The FERC also has responsibility for approving both cost- and market-based rates under which the Utilities sell electricity at wholesale, has licensing authority over most of PacifiCorp's hydroelectric generating facilities and has broad jurisdiction over energy markets. The FERC may impose price limitations, bidding rules and other mechanisms to address some of the volatility of these markets or could revoke or restrict the ability of the Utilities to sell electricity at market-based rates, which could adversely affect our consolidated financial results. As a transmission owning member of the MISO, MidAmerican Energy is also subject to MISO-directed modifications of market rules, which are subject to FERC approval and operational procedures. The FERC may also impose substantial civil penalties for any non-compliance with the Federal Power Act and the FERC's rules and orders.

The FERC has jurisdiction over the construction and operation of natural gas pipelines and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the rates, charges and terms and conditions of service for the transportation, storage and sale of natural gas in interstate commerce and the modification or abandonment of such facilities and rates. The FERC also has market transparency authority and has adopted additional reporting and internet posting requirements for natural gas pipelines and buyers and sellers of natural gas.

Rates for our interstate natural gas transmission and storage operations at the Pipeline Companies are established by the FERC. In accordance with the FERC's rate-making principles, the Pipeline Companies current maximum tariff rates are designed to recover prudently incurred costs included in their pipeline system's regulatory cost of service that are associated with the construction, operation and maintenance of their pipeline system and to afford our Pipeline Companies an opportunity to earn a reasonable rate of return. Nevertheless, the rates the FERC authorizes our Pipeline Companies to charge their customers may not be sufficient to cover the costs incurred to provide services in any given period. Moreover, from time to time, the FERC may change, alter or refine its policies or methodologies for establishing pipeline rates and terms and conditions of service. In addition, the FERC has expressed its intent to continue reviewing data submitted in interstate natural gas pipelines' annual FERC Form 2 filings to determine whether pipelines may be earning more than their allowed rate of return and, when appropriate, to institute proceedings against such pipelines under Section 5 of the NGA to reduce rates. It is not possible to determine at this time whether any such actions would be instituted with respect to our Pipeline Companies' rates or what the outcome would be, but such proceedings could result in rate adjustments.

Under FERC policy, interstate pipelines and their customers may execute contracts at negotiated rates, which may be above or below the FERC regulated maximum tariff rate for that service. In a rate proceeding, these negotiated or discounted rate contracts are generally not subject to adjustment for increased costs which could occur due to inflation, increases in the cost of capital or taxes or other factors. It is possible that the cost to perform services under negotiated or discounted rate contracts will exceed the expected cost used when the negotiated or discounted rates were agreed to, which could result either in losses or lower rates of return in providing such services. FERC policy allows interstate natural gas pipelines to recover such costs under certain circumstances in rate cases. However, with respect to discounts granted to affiliates and negotiated rates, the interstate natural gas pipeline has a strong burden of proof to support such recovery on the basis that the discounted or negotiated rate was necessary in order to meet competition.

United Kingdom Electricity Distribution

The Distribution Companies, as DNOs and holders of electricity distribution licenses, are subject to regulation by GEMA. Most of the revenue of a DNO is controlled by a distribution price control formula set out in the electricity distribution license. The price control formula does not directly constrain profits from year to year, but is a control on revenue that operates independently of most of the DNO's costs. A resetting of the formula requires the consent of the DNO; however, license modifications may be unilaterally imposed by Ofgem without such consent following review by the British competition commission. GEMA is able to impose financial penalties on DNOs that contravene any of their electricity distribution license duties or certain of their duties under British law, or fail to achieve satisfactory performance of individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the DNO's revenue. During the term of the price control, additional costs have a direct impact on the financial results of the Distribution Companies.

Through our subsidiaries, we are actively pursuing, developing and constructing new or expanded facilities, the completion and expected cost of which are subject to significant risk, and our subsidiaries have significant funding needs related to their planned capital expenditures.

Through our subsidiaries, we actively pursue, develop and construct new or expanded facilities. We expect that these subsidiaries will incur substantial annual capital expenditures over the next several years. Such expenditures could include, among others, amounts for new electric generating facilities, electric transmission or distribution projects, environmental control and compliance systems, natural gas storage facilities, new or expanded pipeline systems, as well as the continued maintenance and upgrades of existing assets.

Development and construction of major facilities are subject to substantial risks, including fluctuations in the price and availability of commodities, manufactured goods, equipment, labor, siting and permitting and other items over a multi-year construction period, as well as counterparty risk and the economic viability of our suppliers, customers and contractors. Certain of our construction projects are substantially dependent upon a single contractor and replacement of such contractor may be difficult and cannot be assured. These risks may result in the inability to timely complete a project or higher than expected costs to complete an asset and place it in service. Such costs may not be recoverable in the regulated rates or market or contract prices our subsidiaries are able to charge their customers. It is also possible that additional generation needs may be obtained through power purchase agreements, which could increase long-term purchase obligations and force reliance on the operating performance of a third party. The inability to successfully and timely complete a project, avoid unexpected costs or to recover any such costs could adversely affect our consolidated financial results.

Furthermore, our subsidiaries depend upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. In some cases, we will commit to provide significant amounts of equity to our subsidiaries that are engaged in construction projects. If we do not provide needed funding to our subsidiaries and the subsidiaries are unable to obtain funding from external sources, they may need to postpone or cancel planned capital expenditures.

Failure to construct these planned projects could limit opportunities for revenue growth, increase operating costs and adversely affect the reliability of electricity service to our customers. For example, if PacifiCorp is not able to expand its existing portfolio of generating facilities, it may be required to enter into long-term wholesale electricity purchase contracts or purchase wholesale electricity at more volatile and potentially higher prices in the spot markets to support retail loads.

A sustained decrease in demand for electricity or natural gas in the markets served by our subsidiaries would significantly decrease our operating revenue and adversely affect our consolidated financial results.

A sustained decrease in demand for electricity or natural gas in the markets served by our subsidiaries would significantly reduce our operating revenue and adversely affect our consolidated financial results. Factors that could lead to a decrease in market demand include, among others:

- a depression, recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on electricity or natural gas, such as the significant adverse changes in the economy and credit markets experienced in 2008 and 2009;
- an increase in the market price of electricity or natural gas or a decrease in the price of other competing forms of energy;
- shifts in competitively priced natural gas supply sources away from the sources connected to our Pipeline Companies' systems;
- efforts by customers, legislators and regulators to reduce the consumption of energy through various conservation and energy efficiency measures and programs;
- laws mandating or encouraging renewable energy resources which may reduce the demand for natural gas;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of natural gas or other fuel sources for electricity generation or that limit the use of natural gas or the generation of electricity from fossil fuels; and
- a shift to more energy-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, legislation mandating higher fuel economy or lower emissions, price differentials, incentives or otherwise.

Our subsidiaries are subject to market risk associated with the wholesale energy markets, which could adversely affect our consolidated financial results.

In general, our primary market risk is the risk of adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas, coal and fuel oil, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. The market price of wholesale electricity may be influenced by several factors, such as the adequacy or type of generating capacity; scheduled and unscheduled outages of generating facilities; prices and availability of fuel sources for generation; disruptions or constraints to transmission and distribution facilities; weather conditions; economic growth; and changes in technology. Volumetric changes are caused by unanticipated changes in generation availability or changes in customer needs that can be due to the weather, electricity and fuel prices, the economy, regulations or customer behavior. For example, the Utilities purchase electricity and fuel in the open market as part of their normal operating businesses. If market prices rise, especially in a time when larger than expected volumes must be purchased at market or short-term prices, PacifiCorp or MidAmerican Energy may incur significantly greater expense than anticipated. Likewise, if electricity market prices decline in a period when PacifiCorp or MidAmerican Energy is a net seller of electricity in the wholesale market, PacifiCorp or MidAmerican Energy will earn less revenue.

Our subsidiaries are subject to counterparty credit risk, which could adversely affect our consolidated financial results.

Our subsidiaries are subject to counterparty credit risk related to contractual obligations with wholesale suppliers, customers and, as is the case for MidAmerican Energy, other participants in organized RTO markets. Adverse economic conditions or other events affecting counterparties with whom our subsidiaries conduct business could impair the ability of these counterparties to timely pay for services. Our subsidiaries depend on these counterparties to remit payments on a timely basis. For example, certain wholesale suppliers, customers and other RTO market participants experienced deteriorating credit quality in 2008 and 2009. If our wholesale customers are unable to pay us for energy, there may be a significant adverse impact on our consolidated financial results.

Transactional activities of MidAmerican Energy and other participants in organized RTO markets are governed by credit policies specified in each respective RTO's governing tariff and related business practices. Credit policies of RTO's, which have been developed through extensive stakeholder participation, generally seek to minimize potential loss in the event of a market participant default without unnecessarily inhibiting access to the marketplace. In the event of a default by a RTO market participant on its market-related obligations, losses are allocated among all other market participants in proportion to each participant's share of overall market activity during the period of time the loss was incurred. Because of this, MidAmerican Energy has potential indirect exposure to every other market participant in the RTO markets where it actively participates, including the MISO, the PJM, and the ERCOT.

We continue to monitor the creditworthiness of wholesale suppliers and customers in an attempt to reduce the impact of any potential counterparty default. If strategies used to minimize these risk exposures are ineffective or if our subsidiaries' wholesale customers' financial condition deteriorates as a result of economic conditions causing them to be unable to pay, significant losses could result. Although our subsidiaries monitor the creditworthiness of their customers in an attempt to reduce the impact of any potential counterparty default, defaults in payment could adversely affect our consolidated financial results.

Our subsidiaries are subject to counterparty performance risk, which could adversely affect our consolidated financial results.

Our subsidiaries are subject to counterparty performance risk related to performance of contractual obligations by wholesale suppliers, customers and, as is the case for MidAmerican Energy, other participants in organized RTO markets. Each subsidiary relies on wholesale suppliers to deliver commodities, primarily natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure or delay by suppliers to provide these commodities pursuant to existing contracts could disrupt the delivery of electricity and require the utilities to incur additional expenses to meet customer needs. In addition, when these contracts terminate, the utilities may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

Our subsidiaries rely on wholesale customers to take delivery of the energy they have committed to purchase. Failure of customers to take delivery may require these subsidiaries to find other customers to take the energy at lower prices than the original customers committed to pay. If our subsidiaries' wholesale customers are unable to fulfill their obligations, there may be a significant adverse impact on our consolidated financial results.

Our subsidiaries are subject to the risk that customers will not renew their contracts or that our subsidiaries will be unable to obtain new customers for expanded capacity, each of which could adversely affect our consolidated financial results.

Certain of our subsidiaries are dependent upon a relatively small number of customers for a significant portion of their revenue. For example:

- a significant portion of the Pipeline Companies' capacity is contracted under long-term arrangements, and the Pipeline Companies are dependent upon relatively few customers for a substantial portion of their revenue; and
- generally, a single power purchaser takes electricity from our Philippine hydroelectric generating facility and each of our United States qualifying generating facilities and, when commercially operational, from our unregulated solar-powered projects.

If our subsidiaries are unable to renew, remarket, or find replacements for their customer agreements on favorable terms, our sales volumes and operating revenue would be exposed to reduction and increased volatility. For example, without the benefit of long-term transportation agreements, we cannot assure that the Pipeline Companies will be able to transport natural gas at efficient capacity levels. Similarly, without long-term power purchase agreements, we cannot assure that our unregulated power generators will be able to operate profitably. Failure to maintain existing long-term agreements or secure new long-term agreements, or being required to discount rates significantly upon renewal or replacement, could adversely affect our consolidated financial results. The replacement of any existing long-term agreements depends on market conditions and other factors that may be beyond our subsidiaries' control.

Disruptions in the financial markets could affect our and our subsidiaries' ability to obtain debt financing, draw upon or renew existing credit facilities, and have other adverse effects on us and our subsidiaries.

During 2008 and 2009, the United States, the United Kingdom and global credit markets experienced historic dislocations and liquidity disruptions that caused financing to be unavailable in certain cases. These circumstances materially impacted liquidity in the bank and debt capital markets during this period, making financing terms less attractive for borrowers that were able to find financing, and in other cases resulted in the unavailability of certain types of debt financing. While there has been a gradual recovery in the United States economy and an improvement in its financial markets, there remains much financial and economic uncertainty on a global basis, especially in the European community, which may adversely affect the United States' credit markets. Uncertainty in the credit markets may negatively impact our and our subsidiaries' ability to access funds on favorable terms or at all. If we or our subsidiaries are unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of our capital expenditures, acquisition financing and our consolidated financial results.

Inflation and changes in commodity prices and fuel transportation costs may adversely affect our consolidated financial results.

Inflation may affect our businesses by increasing both operating and capital costs. As a result of existing rate agreements, contractual arrangements or competitive price pressures, our subsidiaries may not be able to pass the costs of inflation on to their customers. If our subsidiaries are unable to manage cost increases or successfully pass them on to their customers, our consolidated financial results could be adversely affected.

Some of our subsidiaries' financial results may be adversely affected if they are unable to obtain adequate, reliable and affordable access to electricity transmission service and natural gas transportation.

Some of our subsidiaries depend on electricity transmission and natural gas transportation facilities owned and operated by other companies to transport electricity and natural gas to both wholesale and retail markets, as well as natural gas purchased to supply certain of our subsidiaries' generating facilities. A lack of available transmission and transportation could hinder our subsidiaries from providing adequate or cost-effective electricity or natural gas to their wholesale markets and retail electric and natural gas customers and could adversely affect our consolidated financial results.

The different regional power markets have varying and dynamic regulatory structures, which could affect our businesses' growth and performance. In addition, the independent system operators who oversee the transmission systems in certain portions of the regional power markets in which we transact have imposed in the past, and may impose in the future, price limitations and other mechanisms to counter volatility in the power markets. These types of price limitations and other mechanisms may adversely affect our consolidated financial results.

Our operating results may fluctuate on a seasonal and quarterly basis and may be adversely affected by weather.

In most parts of the United States and other markets in which our subsidiaries operate, demand for electricity peaks during the hot summer months when irrigation and cooling needs are higher. Market prices for electricity also generally peak at that time. In other areas, demand for electricity peaks during the winter. In addition, demand for natural gas and other fuels generally peaks during the winter when heating needs are higher. This is especially true in Northern Natural Gas' market area and MidAmerican Energy's retail natural gas business. Further, extreme weather conditions, such as heat waves, winter storms or floods could cause these seasonal fluctuations to be more pronounced. Periods of low rainfall or snowpack may impact electricity generation at PacifiCorp's hydroelectric generating facilities, which may result in greater purchases of electricity from the wholesale market or from other sources at market prices. Additionally, the Utilities have added substantial wind-powered generating capacity, and our unregulated businesses are adding solar-powered generating capacity, each of which is also a climate-dependent resource.

As a result, the overall financial results of our subsidiaries may fluctuate substantially on a seasonal and quarterly basis. We have historically sold less energy, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect our consolidated financial results through lower revenue or margins. Conversely, unusually extreme weather conditions could increase our costs to provide energy and could adversely affect our consolidated financial results. The extent of fluctuation in our consolidated financial results may change depending on a number of factors related to our subsidiaries' regulatory environment and contractual agreements, including their ability to recover energy costs, the existence of revenue sharing provisions and terms of the wholesale sale contracts.

Our subsidiaries are subject to operating uncertainties that could adversely affect our consolidated financial results.

The operation of complex, integrated electric and natural gas utility (including generation, transmission and distribution) systems or interstate natural gas pipeline systems that are spread over large geographic areas involves many operating uncertainties and events beyond our control. These potential events include the breakdown or failure of electricity generating equipment, compressors, pipelines, transmission and distribution lines or other equipment or processes; unscheduled generating facility outages; strikes, lockouts or other labor-related actions; shortage of qualified labor; transmission and distribution system constraints or outages; cyber attacks; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; low water flows and other weather-related impacts; performance below expected levels of output, capacity or efficiency; operator error and catastrophic events such as severe storms, floods, fires, earthquakes, explosions, and mining accidents. A catastrophic event might result in injury or loss of life, extensive property damage or environmental damage. Any of these risks or other operational risks could significantly reduce or eliminate our subsidiaries' revenue or significantly increase their expenses, thereby reducing the availability of distributions to us. For example, if our subsidiaries cannot operate their electricity or natural gas facilities at full capacity due to damage caused by a catastrophic event, their revenue could decrease and their expenses could increase due to the need to obtain energy from more expensive sources. Further, we and our subsidiaries self-insure many risks, and current and future insurance coverage may not be sufficient to replace lost revenue or cover repair and replacement costs. The scope, cost and availability of our and our subsidiaries' insurance coverage may change, including the portion that is self-insured. Any reduction of our subsidiaries' revenue or increase in their expenses resulting from the risks described above, could adversely affect our consolidated financial results.

Potential terrorist activities or military or other actions, including cyber attacks, could adversely affect our consolidated financial results.

The ongoing threat of terrorism and the impact of military and other actions by the United States and its allies create increased political, economic and financial market instability, which subjects our subsidiaries' operations to increased risks. The United States government has issued warnings that energy assets, specifically pipeline, nuclear generation and other electric utility infrastructure are potential targets for terrorist organizations. Cyber attacks could adversely affect our subsidiaries' ability to operate their facilities, information technology and business systems, or compromise confidential customer and employee information. Political, economic or financial market instability or damage to the operating assets of our subsidiaries, customers or suppliers may result in business interruptions, lost revenue, higher commodity prices, disruption in fuel supplies, lower energy consumption and unstable markets, particularly with respect to electricity and natural gas, increased security, repair or other costs that may materially adversely affect us and our subsidiaries in ways that cannot be predicted at this time. Any of these risks could materially affect our consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism, sustained or significant cyber attacks, or war could also materially adversely affect our ability and the ability of our subsidiaries to raise capital.

MidAmerican Energy is subject to the unique risks associated with nuclear generation.

The ownership and operation of nuclear power plants, such as MidAmerican Energy's 25% ownership interest in Quad Cities Station, involves certain risks. These risks include, among other items, mechanical or structural problems, inadequacy or lapses in maintenance protocols, the impairment of reactor operation and safety systems due to human error, the costs of storage, handling and disposal of nuclear materials, limitations on the amounts and types of insurance coverage commercially available, and uncertainties with respect to the technological and financial aspects of decommissioning nuclear facilities at the end of their useful lives. The prolonged unavailability of Quad Cities Station could materially adversely affect MidAmerican Energy's financial results, particularly when the cost to produce power at the plant is significantly less than market wholesale prices. The following are among the more significant of these risks:

- *Operational Risk* - Operations at any nuclear power plant could degrade to the point where the plant would have to be shut down. If such degradations were to occur, the process of identifying and correcting the causes of the operational downgrade to return the plant to operation could require significant time and expense, resulting in both lost revenue and increased fuel and purchased electricity costs to meet supply commitments. Rather than incurring substantial costs to restart the plant, the plant could be shut down. Furthermore, a shut-down or failure at any other nuclear plant could cause regulators to require a shut-down or reduced availability at Quad Cities Station.
- *Regulatory Risk* - The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act applicable regulations or the terms of the licenses of nuclear facilities. Unless extended, the NRC operating licenses for Quad Cities Station will expire in 2032. Changes in regulations by the NRC could require a substantial increase in capital expenditures or result in increased operating or decommissioning costs.
- *Nuclear Accident and Catastrophic Risks* - Accidents and other unforeseen catastrophic events have occurred at nuclear facilities other than Quad Cities Station, both in the United States and elsewhere, such as at the Fukushima Daiichi nuclear plant in Japan as a result of the earthquake and tsunami in March 2011. The consequences of an accident or catastrophic event can be severe and include loss of life and property damage. Any resulting liability from a nuclear accident or catastrophic event could exceed MidAmerican Energy's resources, including insurance coverage.

We own investments and projects located in foreign countries that are exposed to increased economic, regulatory and political risks.

We own and may acquire significant energy-related investments and projects outside of the United States. In addition to any disruption in the global financial markets, the economic, regulatory and political conditions in some of the countries where we have operations or are pursuing investment opportunities may present increased risks related to, among others, inflation, foreign currency exchange rate fluctuations, currency repatriation restrictions, nationalization, renegotiation, privatization, availability of financing on suitable terms, customer creditworthiness, construction delays, business interruption, political instability, civil unrest, guerilla activity, terrorism, expropriation, trade sanctions, contract nullification and changes in law, regulations or tax policy. We may not be capable of either fully insuring against or effectively hedging these risks.

We are exposed to risks related to fluctuations in foreign currency exchange rates.

Our business operations and investments outside the United States increase our risk related to fluctuations in foreign currency exchange rates, primarily the British pound. Our principal reporting currency is the United States dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from our foreign operations changes with the fluctuations of the currency in which they transact. We may selectively reduce some foreign currency exchange rate risk by, among other things, requiring contracted amounts be settled in, or indexed to, United States dollars or a currency freely convertible into United States dollars, or hedging through foreign currency derivatives. These efforts, however, may not be effective and could negatively affect our consolidated financial results. We may not be able to obtain sufficient dollars or other hard currency or available dollars may not be allocated to pay such obligations, which could adversely affect our consolidated financial results.

Cyclical fluctuations in the residential real estate brokerage and mortgage businesses could adversely affect HomeServices.

The residential real estate brokerage and mortgage industries tend to experience cycles of greater and lesser activity and profitability and are typically affected by changes in economic conditions, including the current downturn in the United States housing market, which are beyond HomeServices' control. Any of the following, among others, are examples of items that could have a material adverse effect on HomeServices' businesses by causing a general decline in the number of home sales, sale prices or the number of home financings which, in turn, would adversely affect its financial results:

- rising interest rates or unemployment rates, including the significant rise in unemployment in the United States which may continue into future periods;
- periods of economic slowdown or recession in the markets served, such as the significant adverse changes in the economy experienced in recent years;
- decreasing home affordability;
- lack of available mortgage credit for potential homebuyers, such as the reduced availability of credit generally experienced in recent years and that may continue into future periods;
- declining demand for residential real estate as an investment;
- nontraditional sources of new competition; and
- changes in applicable tax law.

Poor performance of plan and fund investments and other factors impacting the pension and other postretirement benefit plans and nuclear decommissioning and mine reclamation trust funds could unfavorably impact our cash flows and liquidity.

Costs of providing our defined benefit pension and other postretirement benefit plans depend upon a number of factors, including the rates of return on plan assets, the level and nature of benefits provided, discount rates, the interest rates used to measure required minimum funding levels, changes in benefit design, changes in laws and government regulation and our required or voluntary contributions made to the plans. All of our pension plans and PacifiCorp's other postretirement benefit plan are in underfunded positions. Even with sustained growth in the investments over future periods to increase the value of these plans' assets, we will likely be required to make significant cash contributions to fund these plans in the future. Additionally, our plans have investments in sovereign debt and foreign currency denominated securities. Credit rating downgrades and default by the entities in which our plans have invested could add to the volatility and timing of future contributions. Furthermore, the Pension Protection Act of 2006, as amended, may result in more volatility in the amount and timing of future contributions. Similarly, funds dedicated to nuclear decommissioning and mine reclamation are invested in debt and equity securities and poor performance of these investments will reduce the amount of funds available for their intended purpose, which would require us to make additional cash contributions. Such cash funding obligations, which are also impacted by the other factors described above, could have a material impact on our liquidity by reducing our cash flows.

We and our subsidiaries are involved in numerous legal proceedings, the outcomes of which are uncertain and could adversely affect our consolidated financial results.

We and our subsidiaries are party to numerous legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters. It is possible that the final resolution of some of the matters in which we and our subsidiaries are involved could result in additional payments in excess of established reserves over an extended period of time and in amounts that could have a material adverse effect on our consolidated financial results. Similarly, it is also possible that the terms of resolution could require that we or our subsidiaries change business practices and procedures, which could also have a material adverse effect on our consolidated financial results. Further, litigation could result in the imposition of financial penalties or injunctions which could limit our ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct our business, including the siting or permitting of facilities. Any of these outcomes could adversely affect our consolidated financial results.

Potential changes in accounting standards may impact our consolidated financial results and disclosures in the future, which may change the way analysts measure our business or financial performance.

The Financial Accounting Standards Board ("FASB") and the SEC continuously make changes to accounting standards and disclosure and other financial reporting requirements. New or revised accounting standards and requirements issued by the FASB or the SEC or new accounting orders issued by the FERC could significantly impact our consolidated financial results and disclosures.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

The Company's energy properties consist of the physical assets necessary to support its electricity and natural gas businesses. Properties of the Company's electricity businesses include electric generation, transmission and distribution facilities, as well as coal mining assets that support certain of the Company's electric generating facilities. Properties of the Company's natural gas businesses include natural gas distribution facilities, interstate pipelines, storage facilities, compressor stations and meter stations. In addition to these physical assets, the Company has rights-of-way, mineral rights and water rights that enable the Company to utilize its facilities. It is the opinion of the Company's management that the principal depreciable properties owned by the Company are in good operating condition and are well maintained. Pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties and substantially all of the assets of Cordova Energy Company LLC are pledged or encumbered to support or otherwise provide the security for their related subsidiary debt. For additional information regarding the Company's energy properties, refer to Item 1 of this Form 10-K and Notes 3, 4 and 22 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

The following table summarizes the electric generating facilities of MEHC's subsidiaries as of December 31, 2011:

Energy Source	Entity	Location by Significance	Facility Net Capacity (MW)	Net Owned Capacity (MW)
Coal	PacifiCorp and MidAmerican Energy	Iowa, Wyoming, Utah, Arizona, Colorado and Montana	14,326	9,538
Natural gas and other	PacifiCorp, MidAmerican Energy and MidAmerican Renewables	Utah, Iowa, Illinois, Washington, Oregon, Texas, New York and Arizona	4,829	4,311
Wind	PacifiCorp and MidAmerican Energy	Iowa, Wyoming, Washington and Oregon	2,918	2,909
Hydroelectric	PacifiCorp, MidAmerican Energy and MidAmerican Renewables	Washington, Oregon, The Philippines, Idaho, California, Utah, Hawaii, Montana, Illinois and Wyoming	1,308	1,281
Nuclear	MidAmerican Energy	Illinois	1,760	440
Geothermal	PacifiCorp and MidAmerican Renewables	California and Utah	361	198
		Total	25,502	18,677

The right to construct and operate the Company's electric transmission and distribution facilities and interstate natural gas pipelines across certain property was obtained in most circumstances through negotiations and, where necessary, through the exercise of the power of eminent domain. PacifiCorp, MidAmerican Energy, Northern Natural Gas and Kern River in the United States and Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc in Great Britain continue to have the power of eminent domain in each of the jurisdictions in which they operate their respective facilities, but the United States utilities do not have the power of eminent domain with respect to governmental or Native American tribal lands. Although the main Kern River pipeline crosses the Moapa Indian Reservation, all facilities in the Moapa Indian Reservation are located within a utility corridor that is reserved to the United States Department of Interior, Bureau of Land Management.

With respect to real property, each of the electric transmission and distribution facilities and interstate natural gas pipelines fall into two basic categories: (1) parcels that are owned in fee, such as certain of the electric generation stations, electric substations, natural gas compressor stations, natural gas meter stations and office sites; and (2) parcels where the interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for the construction, operation and maintenance of the electric transmission and distribution facilities and interstate natural gas pipelines. The Company believes that each of its energy subsidiaries has satisfactory title to all of the real property making up their respective facilities in all material respects.

Item 3. Legal Proceedings

None

Item 4. Mine Safety Disclosures

Information regarding the Company's mine safety violations and other legal matters disclosed in accordance with Section 1503 (a) of the Dodd-Frank Reform Act is included in Exhibit 95 to this Form 10-K.

PART II

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

MEHC's common stock is owned by Berkshire Hathaway, Mr. Walter Scott, Jr. and certain of his family members and family controlled trusts and corporations, and Mr. Gregory E. Abel, its Chairman, President and Chief Executive Officer, and has not been registered with the SEC pursuant to the Securities Act of 1933, as amended, listed on a stock exchange or otherwise publicly held or traded. MEHC has not declared or paid any cash dividends on its common stock during the last ten fiscal years and does not presently anticipate that it will declare any dividends on its common stock in the foreseeable future.

For a discussion of unregistered sales of equity securities and regulatory restrictions that limit PacifiCorp's and MidAmerican Energy's ability to pay dividends on their common stock to MEHC, refer to Note 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Item 6. Selected Financial Data

The following table sets forth the Company's selected consolidated historical financial data, which should be read in conjunction with the information in Item 7 of this Form 10-K and with the Company's historical Consolidated Financial Statements and notes thereto in Item 8 of this Form 10-K. The selected consolidated historical financial data has been derived from the Company's audited historical Consolidated Financial Statements and notes thereto (in millions).

	Years Ended December 31,				
	2011	2010	2009	2008	2007
Consolidated Statement of Operations Data:					
Operating revenue	$ 11,173	$ 11,127	$ 11,204	$ 12,668	$ 12,376
Net income[1]	1,352	1,310	1,188	1,871	1,219
Net income attributable to noncontrolling interests	21	72	31	21	30
Net income attributable to MEHC[1]	1,331	1,238	1,157	1,850	1,189

	As of December 31,				
	2011	2010	2009	2008	2007
Consolidated Balance Sheet Data:					
Total assets	$ 47,718	$ 45,668	$ 44,684	$ 41,441	$ 39,216
Short-term debt	865	320	179	836	130
Long-term debt, including current maturities:					
MEHC senior debt	5,363	5,371	5,371	5,121	5,471
MEHC subordinated debt	22	315	590	1,321	1,125
Subsidiary debt	13,687	13,805	13,791	12,954	13,097
Total MEHC shareholders' equity	14,092	13,232	12,576	10,207	9,326
Noncontrolling interests	173	176	267	270	256

(1) Reflects the $646 million after-tax gain recognized on the termination of the Constellation Energy Group, Inc. ("Constellation Energy") merger agreement on December 17, 2008.

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

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of the Company during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with Item 6 of this Form 10-K and with the Company's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. The Company's actual results in the future could differ significantly from the historical results.

The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to the Company's significant accounting policies. The differences between the segment amounts and the consolidated amounts, described as "MEHC and Other," relate principally to corporate functions, including administrative costs and intersegment eliminations. Effective December 31, 2011, the Company changed its reportable segments. Northern Natural Gas and Kern River have been aggregated in the reportable segment called MidAmerican Energy Pipeline Group, and CalEnergy Philippines and MidAmerican Renewables, LLC, formerly CalEnergy U.S., have been aggregated in the reportable segment called MidAmerican Renewables. Prior year amounts have been changed to conform to the current presentation.

Results of Operations

Overview

Net income attributable to MEHC for 2011 was $1.331 billion, an increase of $93 million, or 8%, compared to 2010. PacifiCorp's net income was $554 million for 2011, a decrease of $15 million, or 3%, compared to 2010 as higher retail prices approved by regulators, higher customer load and the net impact of the Utah general rate case settlement were more than offset by lower wholesale revenue, higher purchased power costs, lower AFUDC, higher depreciation and amortization, higher operating expense and lower sales of RECs. Net income at MidAmerican Funding was $304 million for 2011, a decrease of $36 million, or 11%, compared to 2010 due to lower wholesale electric margins, resulting from lower average prices and volumes, and the effects of ratemaking on income taxes, partially offset by higher AFUDC, lower interest expense, lower operating expense and lower depreciation and amortization. MidAmerican Energy Pipeline Group's net income was $236 million for 2011, an increase of $11 million, or 5%, compared to 2010 due to lower interest expense and higher AFUDC. Northern Powergrid Holdings' net income was $389 million for 2011, an increase of $113 million, or 41%, compared to 2010 due to higher distribution revenue resulting from lower regulatory provisions and higher tariffs, higher deferred income tax benefits in 2011 related to enacted changes in the United Kingdom's corporate income tax rate and $12 million due to a weaker United States dollar, partially offset by a tax free gain of $45 million recognized on the sale of CE Gas (Australia) Limited in 2010. Additionally, net income attributable to MEHC was favorably impacted by an after-tax charge of $38 million related to the CE Casecnan noncontrolling interest settlement in 2010, lower MEHC subordinated interest expense in 2011 of $16 million, higher variable energy and water delivery fees earned in 2011 on higher rainfall at the Casecnan project totaling $14 million and higher equity income from ETT in 2011 of $10 million, partially offset by charges associated with the early redemption of MEHC subordinated debt in 2011 totaling $24 million and a dividend received in 2010 from BYD Company Limited totaling $6 million.

Net income attributable to MEHC for 2010 was $1.238 billion, an increase of $81 million, or 7%, compared to 2009. PacifiCorp's net income was $569 million for 2010, an increase of $27 million, or 5%, compared to 2009 due to higher retail prices approved by regulators, higher sales of RECs, higher benefits associated with deferred net power costs, higher AFUDC and a lower effective income tax rate due to the effects of ratemaking and higher production tax credits, partially offset by lower net wholesale electricity activities, higher depreciation on higher plant placed in-service and higher operating expense. Net income at MidAmerican Energy was $340 million for 2010, an increase of $13 million, or 4%, compared to 2009 due to higher margins on warmer weather and $21 million of income tax benefits for changes related to the tax capitalization policy for overhead costs and repairs deductions. These improvements were partially offset by higher maintenance costs from plant outages and storm damage. MidAmerican Energy Pipeline Group's net income was $225 million for 2010, a decrease of $49 million, or 18%, compared to 2009 as a result of lower revenue from less favorable market conditions. Net income at Northern Powergrid Holdings was $276 million for 2010, an increase of $98 million, or 55%, compared to 2009 due to a $45 million tax free gain on the sale of CE Gas (Australia) Limited, the recognition of deferred income tax benefits totaling $25 million upon enactment of the reduction in the United Kingdom corporate income tax rate from 28% to 27%, a $15 million after-tax impairment of certain Australian hydrocarbon exploration and development assets in 2009 and higher distribution revenue. Additionally, net income attributable to MEHC was unfavorably impacted by the noncontrolling interest settlement totaling $38 million, lower rainfall and related lower revenue earned in 2010 at the Casecnan project totaling $23 million and an after-tax gain in 2009 on the Constellation Energy common stock investment of $22 million, partially offset by an after-tax stock-based compensation charge of $75 million in 2009 as a result of the purchase of shares of common stock that were issued upon the exercise of stock options.

Segment Results

Operating revenue and operating income for the Company's reportable segments for the years ended December 31 are summarized as follows (in millions):

	2011	2010	Change		2010	2009	Change	
Operating revenue:								
PacifiCorp	$ 4,586	$ 4,432	$ 154	3%	$ 4,432	$ 4,457	$ (25)	(1)%
MidAmerican Funding	3,503	3,815	(312)	(8)	3,815	3,699	116	3
MidAmerican Energy Pipeline Group	977	981	(4)	—	981	1,061	(80)	(8)
Northern Powergrid Holdings	1,014	802	212	26	802	825	(23)	(3)
MidAmerican Renewables	161	137	24	18	137	178	(41)	(23)
HomeServices	992	1,020	(28)	(3)	1,020	1,037	(17)	(2)
MEHC and Other	(60)	(60)	—	—	(60)	(53)	(7)	(13)
Total operating revenue	$ 11,173	$ 11,127	$ 46	—	$ 11,127	$ 11,204	$ (77)	(1)
Operating income:								
PacifiCorp	$ 1,099	$ 1,055	$ 44	4%	$ 1,055	$ 1,079	$ (24)	(2)%
MidAmerican Funding	428	460	(32)	(7)	460	469	(9)	(2)
MidAmerican Energy Pipeline Group	468	472	(4)	(1)	472	558	(86)	(15)
Northern Powergrid Holdings	615	474	141	30	474	394	80	20
MidAmerican Renewables	106	88	18	20	88	128	(40)	(31)
HomeServices	24	17	7	41	17	11	6	55
MEHC and Other	(56)	(64)	8	13	(64)	(174)	110	63
Total operating income	$ 2,684	$ 2,502	$ 182	7	$ 2,502	$ 2,465	$ 37	2

PacifiCorp

Operating revenue increased $154 million for 2011 compared to 2010 due to higher retail revenue of $350 million, partially offset by lower wholesale and other revenue of $196 million. The increase in retail revenue was due to higher prices approved by regulators of $280 million and higher customer load. Customer load increased 2% due to higher commercial load in Utah and Oregon, higher industrial load in Utah and the impacts of colder weather on residential load in Oregon. The decrease in wholesale and other revenue was due to a 24% decrease in average wholesale prices and a 6% decrease in wholesale volumes. Additionally, wholesale and other revenue decreased $57 million due to lower sales and higher deferrals of RECs, net of amortization, including the general rate case settlement in Utah totaling $30 million.

Operating income increased $44 million for 2011 compared to 2010 due to the higher operating revenue, partially offset by higher depreciation and amortization of $51 million due to higher plant placed in service, higher operating expense of $41 million and higher energy costs of $18 million. Operating expense increased due to the higher plant placed in service, higher salaries and benefit expenses and material and supplies expense in 2011. Energy costs increased as a result of the higher per unit costs of coal and natural gas totaling $94 million, partially offset by energy cost adjustment mechanisms totaling $76 million, which included the impact of the Utah rate case settlement totaling $60 million. Energy supplied increased 1% for 2011 compared to 2010 as a 23% increase in purchased power volumes, higher than average hydroelectric generation and higher wind-powered generation were partially offset by lower generation from natural gas and coal-fueled generating facilities.

Operating revenue decreased $25 million for 2010 compared to 2009 due to a decrease in wholesale and other revenue of $212 million, partially offset by higher retail revenue of $144 million and an increase in the sale of RECs totaling $43 million. Wholesale and other revenue decreased primarily due to a 17% decrease in average wholesale prices, an 8% decrease in wholesale volumes and the impact of deconsolidating PacifiCorp's coal mining joint venture, Bridger Coal Company ("Bridger Coal"), as a result of adopting authoritative guidance requiring equity method accounting treatment effective January 1, 2010. The lower revenue due to deconsolidating Bridger Coal is largely offset by lower operating expense and depreciation and amortization. Retail revenue increased due to higher prices approved by regulators and higher demand-side management revenue, which is offset by related higher operating expenses, partially offset by lower revenue related to Oregon Senate Bill 408 ("SB 408") and lower customer usage.

Operating income decreased $24 million for 2010 compared to 2009 due to the lower operating revenue, higher depreciation and property taxes associated with recent plant placed in-service and higher maintenance costs primarily due to increased plant overhauls, partially offset by lower energy costs. Energy costs decreased due to a decrease in the average cost of purchased electricity and natural gas, lower natural gas volumes and the effects of regulatory cost recovery adjustment mechanisms for net power costs, partially offset by higher transmission costs of $18 million from higher contract rates, higher volumes of purchased electricity and higher coal prices.

MidAmerican Funding

MidAmerican Funding's operating revenue and operating income for the years ended December 31 are summarized as follows (in millions):

	2011	2010	Change		2010	2009	Change	
Operating revenue:								
Regulated electric	$ 1,662	$ 1,779	$ (117)	(7)%	$ 1,779	$ 1,715	$ 64	4 %
Regulated natural gas	769	852	(83)	(10)	852	857	(5)	(1)
Nonregulated and other	1,072	1,184	(112)	(9)	1,184	1,127	57	5
Total operating revenue	$ 3,503	$ 3,815	$ (312)	(8)	$ 3,815	$ 3,699	$ 116	3
Operating income:								
Regulated electric	$ 294	$ 319	$ (25)	(8)%	$ 319	$ 331	$ (12)	(4)%
Regulated natural gas	66	64	2	3	64	70	(6)	(9)
Nonregulated and other	68	77	(9)	(12)	77	68	9	13
Total operating income	$ 428	$ 460	$ (32)	(7)	$ 460	$ 469	$ (9)	(2)

Regulated electric operating revenue decreased $117 million for 2011 compared to 2010. Wholesale and other revenue decreased $123 million due to lower volumes of 19% and lower average prices of 8%. Retail revenue increased $6 million due to a 1% increase in customer load.

Regulated electric operating income decreased $25 million for 2011 compared to 2010. The lower operating revenue was partially offset by lower energy costs, operating expense and depreciation and amortization. Energy costs decreased $75 million due to lower purchased energy and lower coal and natural gas generation volumes, as lower wholesale sales prices and higher wind-powered generation made it less economical to dispatch these units, partially offset by the higher average cost of natural gas and coal. Operating expense decreased $9 million due to higher maintenance costs in 2010 from plant outages and storm restoration costs. Depreciation and amortization decreased $8 million due to lower depreciation rates effective June 1, 2011 following the results of a depreciation study. The new rates generally reflect longer estimated useful lives and lower net salvage. The effect of this change is estimated to be $28 million annually based on depreciable plant balances at the time of the change.

Regulated natural gas operating revenue decreased $83 million for 2011 compared to 2010 due to lower wholesale volumes of 30% due to the narrowing of natural gas price spreads and a decrease in the average per-unit cost of gas sold, resulting in lower costs of sales. Regulated natural gas operating income increased $2 million for 2011 compared to 2010 due to lower operating expense.

Nonregulated and other operating revenue decreased $112 million for 2011 compared to 2010 due to lower electricity and natural gas volumes and prices. Nonregulated and other operating income decreased $9 million for 2011 compared to 2010 due to lower margins.

Regulated electric operating revenue increased $64 million for 2010 compared to 2009. Retail revenue increased $100 million on higher volumes of 8% due to higher customer usage, primarily as a result of the impacts of favorable weather, and customer growth. Wholesale and other revenue decreased $36 million due to lower average wholesale sales prices and volumes.

Regulated electric operating income decreased $12 million for 2010 compared to 2009. The higher operating revenue was offset by higher energy costs of $44 million, higher operating expenses of $24 million and higher depreciation and amortization of $8 million. Energy costs increased due to higher coal prices and greater thermal generation as a result of higher retail volumes. Operating expenses increased primarily due to higher maintenance costs from plant outages and storm damage totaling $12 million.

Regulated natural gas operating revenue decreased $5 million for 2010 compared to 2009 due to lower wholesale and retail volumes, partially offset by an increase in the average per-unit cost of gas sold, which was passed on to customers. Regulated natural gas operating income decreased $6 million for 2010 compared to 2009 due to higher operating expenses.

Nonregulated and other operating revenue increased $57 million for 2010 compared to 2009 due to a 10% increase in electric retail volumes, partially offset by a 3% decrease in electric retail prices. Nonregulated and other operating income increased $9 million for 2010 compared to 2009 primarily due to higher electric retail margins.

MidAmerican Energy Pipeline Group

Operating revenue decreased $4 million for 2011 compared to 2010 due to lower transportation and storage revenue from the narrowing of natural gas price spreads, partially offset by higher revenue from long-term contracts related to the Apex and 2010 Expansion projects at Kern River totaling $27 million and higher sales of gas and condensate liquids of $10 million. Operating income decreased $4 million for 2011 compared to 2010 due to the lower operating revenue and higher depreciation and amortization of $11 million on assets placed in service, partially offset by lower operating expense due to reduced maintenance costs and lower natural gas storage losses.

Operating revenue decreased $80 million for 2010 compared to 2009 due to lower rates at Kern River as a result of the FERC order received in 2009 and lower natural gas price spreads, partially offset by the 2010 Expansion project at Kern River being placed in service in April 2010 and higher sales of gas and condensate liquids of $7 million. Operating income decreased $86 million for 2010 compared to 2009 due to the lower operating revenue and higher depreciation and amortization of $9 million.

Northern Powergrid Holdings

Operating revenue increased $212 million for 2011 compared to 2010 due to higher distribution revenue of $197 million and a weaker United States dollar totaling $32 million, partially offset by lower contracting revenue of $11 million and lower revenue of $6 million at CE Gas. Distribution revenue increased due to lower regulatory provisions totaling $126 million and higher tariff rates, partially offset by lower distributed units. Operating income increased $141 million for 2011 compared to 2010 due to the higher distribution revenue and a weaker United States dollar totaling $19 million, partially offset by a tax free gain of $45 million recognized on the sale of CE Gas (Australia) Limited in 2010 and higher distribution costs and depreciation and amortization.

Operating revenue decreased $23 million for 2010 compared to 2009 due to lower contracting revenue of $30 million, lower gas production of $17 million and the stronger United States dollar totaling $6 million, partially offset by higher distribution revenue of $31 million. Distribution revenue increased due to higher rates implemented April 1, 2010 related to the Distribution Price Control Review and higher volumes, partially offset by unfavorable movements in certain regulatory provisions totaling $77 million. Operating income increased $80 million for 2010 compared to 2009 due to a tax free gain of $45 million recognized on the sale of CE Gas (Australia) Limited in 2010, a $20 million impairment of certain Australian hydrocarbon exploration and development assets in 2009 and the higher distribution revenue, partially offset by the lower gas production.

MidAmerican Renewables

Operating revenue increased $24 million for 2011 compared to 2010 due to higher variable energy and variable water delivery fees earned in 2011 from higher rainfall at the Casecnan project. Operating income increased $18 million for 2011 compared to 2010 due to the higher revenue at the Casecnan project, partially offset by higher maintenance costs at an independent power project in the United States.

Operating revenue decreased $41 million and operating income decreased $40 million for 2010 compared to 2009 due to lower than normal rainfall in 2010 and above normal rainfall in 2009 at the Casecnan project, which resulted in lower variable energy and water delivery fees earned in 2010.

HomeServices

Operating revenue decreased $28 million for 2011 compared to 2010 due to a 4% decrease in average home sale prices. Operating income increased $7 million for 2011 compared to 2010 as the lower operating revenue, net of commissions, was more than offset by lower operating expense.

Operating revenue decreased $17 million for 2010 compared to 2009 due to a 7% decrease in closed brokerage units, partially offset by higher average home sale prices. Operating income increased $6 million for 2010 compared to 2009 as the lower operating revenue, net of commissions, was more than offset by lower operating expenses.

MEHC and Other

Operating loss decreased $110 million for 2010 compared to 2009 due to $125 million of stock-based compensation expense in 2009 as a result of the purchase of common stock issued by MEHC upon the exercise of the last remaining stock options that had been granted to certain members of management at the time of Berkshire Hathaway's acquisition of MEHC in 2000.

Consolidated Other Income and Expense Items

Interest Expense

Interest expense for the years ended December 31 is summarized as follows (in millions):

	2011	**2010**	**Change**		**2010**	**2009**	**Change**	
Subsidiary debt	$ 841	$ 844	$ (3)	— %	$ 844	$ 864	$ (20)	(2)%
MEHC senior debt and other	329	329	—	—	329	331	(2)	(1)
MEHC subordinated debt-Berkshire Hathaway	13	30	(17)	(57)	30	58	(28)	(48)
MEHC subordinated debt-other	13	22	(9)	(41)	22	22	—	—
Total interest expense	$ 1,196	$ 1,225	$ (29)	(2)	$ 1,225	$ 1,275	$ (50)	(4)

Interest expense decreased $29 million for 2011 compared to 2010 due to scheduled maturities and principal repayments, partially offset by a weaker United States dollar and the debt issuances at PacifiCorp ($400 million in May 2011), Northern Natural Gas ($200 million in April 2011) and Northern Powergrid Holdings (£151 million in the third quarter of 2010 and £119 million in the first quarter of 2011).

Interest expense decreased $50 million for 2010 compared to 2009 due to scheduled maturities, principal repayments and lower interest rates on variable rate debt.

Capitalized Interest

Capitalized interest decreased $14 million for 2011 compared to 2010 due to lower construction work-in-progress balances at PacifiCorp, partially offset by higher construction work-in-progress balances at MidAmerican Energy and Kern River.

Capitalized interest increased $13 million for 2010 compared to 2009 due to higher construction work-in-progress balances at PacifiCorp.

Interest and Dividend Income

Interest and dividend income decreased $10 million for 2011 compared to 2010 due to an $11 million dividend received in 2010 from BYD Company Limited.

Interest and dividend income decreased $14 million for 2010 compared to 2009 due to interest associated with SB 408 refunds received in 2009 at PacifiCorp, income earned in 2009 related to the Constellation Energy investments and lower average cash balances, partially offset by the dividend received in 2010 from BYD Company Limited.

Other, net

Other, net decreased $59 million for 2011 compared to 2010 due to costs associated with the early redemption of MEHC subordinated debt totaling $40 million, lower equity AFUDC of $17 million and lower Rabbi Trust earnings, partially by the impairment of an asset in 2010 totaling $8 million at MidAmerican Funding. Equity AFUDC decreased due to lower construction work-in-progress balances at PacifiCorp, partially offset by higher construction work-in-progress balances at MidAmerican Energy and Kern River.

Other, net decreased $36 million for 2010 compared to 2009 due primarily to a $37 million pre-tax gain on the Constellation Energy common stock investment in 2009 and the impairment of an asset in 2010 at MidAmerican Funding, partially offset by higher equity AFUDC in 2010, primarily at PacifiCorp and MidAmerican Energy.

Income Tax Expense

Income tax expense increased $96 million for 2011 compared to 2010. The effective tax rates were 18% and 14% for 2011 and 2010, respectively. The increase in the effective tax rate was due to the effects of ratemaking, lower tax benefits received at MidAmerican Energy for changes related to the tax capitalization and repairs deductions policies totaling $26 million and higher United States income taxes on foreign earnings, partially offset by additional production tax credits in 2011 totaling $29 million, higher deferred income tax benefits in 2011 related to enacted changes in the United Kingdom's corporate income tax rate discussed below and lower state income taxes.

In July 2011, the Company recognized $40 million of deferred income tax benefits upon the enactment of a reduction in the United Kingdom corporate income tax rate from 27% to 26% effective April 1, 2011, and a further reduction to 25% effective April 1, 2012. In July 2010, the Company recognized $25 million of deferred income tax benefits upon the enactment of the reduction in the United Kingdom corporate income tax rate from 28% to 27% effective April 1, 2011.

Federal renewable electricity production tax credits are earned on qualifying wind-powered generation placed in service. In 2004, the Utilities began placing qualified wind-powered generation in service and that has continued through 2011. Federal renewable electricity production tax credits are recognized as energy from wind-powered generating facilities is sold based on a per kilowatt rate as prescribed pursuant to the applicable federal income tax law and are eligible for the credit for 10 years from the date the qualifying generating facilities were placed in service. A credit of $0.022 per kilowatt hour was applied to 2011 production.

Income tax expense decreased $84 million for 2010 compared to 2009. The effective tax rates were 14% and 20% for 2010 and 2009, respectively. The decrease in the effective tax rate was primarily due to deferred income tax benefits totaling $25 million upon the enactment of the reduction in the United Kingdom corporate income tax rate from 28% to 27%, additional production tax credits totaling $20 million, a non-taxable gain on the sale of CE Gas (Australia) Limited and higher tax benefits received at MidAmerican Energy for changes related to the tax capitalization policy and repairs deductions totaling $6 million, partially offset by the impact of ratemaking. The benefits for changes to the tax capitalization policy and the repairs deductions were realized as MidAmerican Energy changed the method by which it determines current income tax deductions for overhead costs and repairs on certain of its regulated utility assets, which results in current deductibility for costs that are capitalized for book purposes. Iowa, MidAmerican Energy's largest jurisdiction for rate-regulated operations, requires immediate income recognition of such temporary differences.

Equity Income

Equity income increased $10 million for 2011 compared to 2010 due to continued investment at ETT and higher earnings at CE Generation due to improved results at the gas plants, partially offset by lower earnings at HomeServices' mortgage joint venture due to lower refinancing activity and higher compliance costs.

Equity income decreased $12 million for 2010 compared to 2009 due to lower earnings at CE Generation, primarily due to the expiration of a favorable power purchase contract in the second quarter of 2009 at the Saranac project.

Net Income Attributable to Noncontrolling Interests

Net income attributable to noncontrolling interests decreased $51 million for 2011 compared to 2010 and increased $41 million for 2010 compared to 2009 due to a $54 million pre-tax charge in 2010 related to the CE Casecnan noncontrolling interest settlement.

Liquidity and Capital Resources

Each of MEHC's direct and indirect subsidiaries is organized as a legal entity separate and apart from MEHC and its other subsidiaries. It should not be assumed that the assets of any subsidiary will be available to satisfy MEHC's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MEHC or affiliates thereof. The long-term debt of subsidiaries may include provisions that allow MEHC's subsidiaries to redeem it in whole or in part at any time. These provisions generally include make-whole premiums. Refer to Note 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the limitation of distributions from MEHC's subsidiaries.

As of December 31, 2011, the Company's total net liquidity was $3.741 billion. The components of total net liquidity are as follows (in millions):

	MEHC	PacifiCorp	MidAmerican Funding	Northern Powergrid Holdings	Other	Total
Cash and cash equivalents	$ 13	$ 47	$ 1	$ 21	$ 204	$ 286
Credit facilities	552	1,355	654	233	50	2,844
Less:						
Short-term debt	(108)	(688)	—	(69)	—	(865)
Tax-exempt bond support and letters of credit	(25)	(304)	(195)	—	—	(524)
Net credit facilities	419	363	459	164	50	1,455
Net liquidity before Berkshire Equity Commitment	$ 432	$ 410	$ 460	$ 185	$ 254	$ 1,741
Berkshire Equity Commitment(1)	2,000					2,000
Total net liquidity	$ 2,432					$ 3,741
Unsecured revolving credit facilities:						
Maturity date	2013	2012, 2013	2012, 2013	2013	2013	
Largest single bank commitment as a % of total revolving credit facilities(2)	18%	16%	23%	33%	100%	

(1) MEHC has an Equity Commitment Agreement with Berkshire Hathaway (the "Berkshire Equity Commitment") pursuant to which Berkshire Hathaway has agreed to purchase up to $2.0 billion of MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The proceeds of any such equity contribution shall only be used for the purpose of (a) paying when due MEHC's debt obligations and (b) funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries. The Berkshire Equity Commitment expires on February 28, 2014.

(2) An inability of financial institutions to honor their commitments could adversely affect the Company's short-term liquidity and ability to meet long-term commitments.

The above table does not include unused revolving credit facilities and letters of credit for investments that are accounted for under the equity method.

In January 2012, MEHC entered into a $500 million revolving loan agreement with a subsidiary of Berkshire Hathaway that expires June 30, 2012. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the Company's credit facilities.

In January 2012, subsidiaries of MEHC acquired ownership interests in two solar projects. Refer to Note 23 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the Company's equity commitments, letters of credit and other related items.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2011 and 2010 were $3.220 billion and $2.759 billion, respectively. The increase was primarily due to higher income tax receipts of $270 million mainly attributable to bonus depreciation, improved operating results, changes in collateral posted for derivative contracts and a Kern River customer rate refund in 2010, partially offset by changes in working capital.

Net cash flows from operating activities for the years ended December 31, 2010 and 2009 were $2.759 billion and $3.572 billion, respectively. The decrease was mainly due to lower income tax receipts of $391 million due to the timing of repairs deductions and bonus depreciation, changes in collateral posted for derivative contracts, $128 million of net cash flows in 2009 related to the Constellation Energy transaction, which is comprised of $536 million of proceeds received from the sale of Constellation Energy common stock and $408 million of income taxes paid on gains recognized on the termination of the Constellation Energy merger agreement in December 2008 and the sale of stock in 2009, higher contributions to pension and other postretirement benefit plans and rate case refunds paid in 2010 at Kern River.

In September 2010, the President signed the Small Business Jobs Act into law, extending retroactively to January 1, 2010 the 50% bonus depreciation for qualifying property purchased and placed in service in 2010. In December 2010, the President signed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 into law, which provided for 100% bonus depreciation for qualifying property purchased and placed in service after September 8, 2010 and prior to January 1, 2012, and extended 50% bonus depreciation for qualifying property purchased and placed in service after December 31, 2010 and prior to January 1, 2013. As a result of the new laws, the Company's cash flows from operations benefited in 2011 and are expected to benefit in 2012 due to bonus depreciation on qualifying assets placed in service.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2011 and 2010 were $(2.816) billion and $(2.484) billion, respectively. The change was primarily due to higher capital expenditures of $91 million, proceeds received from the sale of certain Australian hydrocarbon exploration and development assets during the second quarter of 2010 totaling $78 million and net proceeds received from the sale of CE Gas (Australia) Limited during the third quarter of 2010 totaling $59 million and higher investments in companies accounted for under the equity method totaling $58 million.

Net cash flows from investing activities for the years ended December 31, 2010 and 2009 were $(2.484) billion and $(2.669) billion, respectively. Capital expenditures decreased $820 million. In January 2009, the Company received $1 billion, plus accrued interest, in full satisfaction of the 14% Senior Notes from Constellation Energy. In July 2009, the Company purchased 225 million shares, representing approximately a 10% interest, of BYD Company Limited common stock for $232 million. Additionally, the Company received proceeds from the sales of certain CE Gas assets in 2010 totaling $137 million, partially offset by higher investments in companies accounted for under the equity method totaling $32 million.

Capital Expenditures

Capital expenditures, which exclude amounts for non-cash equity AFUDC and other non-cash items, by reportable segment for the years ended December 31 are summarized as follows (in millions):

	2011	2010	2009
Capital expenditures:			
PacifiCorp	$ 1,506	$ 1,607	$ 2,328
MidAmerican Funding	566	338	439
MidAmerican Energy Pipeline Group	289	293	250
Northern Powergrid Holdings	309	349	387
Other	14	6	9
Total capital expenditures	$ 2,684	$ 2,593	$ 3,413

The Company's capital expenditures relate primarily to the Utilities and consisted mainly of the following for the years ended December 31:

2011:

- The construction of wind-powered generating facilities at MidAmerican Energy totaling $295 million, which excludes $647 million of costs for which payments are due in December 2013. MidAmerican Energy placed in service 594 MW during 2011 and is constructing an additional 407 MW to be placed in service in 2012.
- Transmission system investments totaling $240 million, including permitting and right-of-way costs for the 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley. A 65-mile segment of the Mona to Oquirrh transmission project will be a single-circuit 500-kV transmission line, while the remaining 35-mile segment will be a double-circuit 345-kV transmission line. The transmission line is expected to be placed in service in 2013.
- Emissions control equipment on existing generating facilities totaling $217 million for installation or upgrade of sulfur dioxide scrubbers, low nitrogen oxide burners and particulate matter control systems.
- The development and construction of the Lake Side 2 637-MW combined-cycle combustion turbine natural gas-fueled generating facility ("Lake Side 2") totaling $180 million, which is expected to be placed in service in 2014.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling $1.140 billion.

2010:

- Emissions control equipment totaling $348 million.
- Transmission system investments totaling $303 million, including construction costs for the first major segment of the Energy Gateway Transmission Expansion Program, a 135-mile, double circuit, 345-kilovolt transmission line between the Populus substation in southern Idaho and the Terminal substation near Salt Lake City, Utah, which was fully placed in-service in 2010.
- The development and construction of wind-powered generating facilities totaling $228 million. During 2010, PacifiCorp placed in service a 111 MW wind-powered generating facility, and MidAmerican Energy began contracting for the construction of 594 MW of wind-powered generating projects.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling $1.066 billion.

2009:

- Transmission system investments totaling $715 million, including a major segment of the Energy Gateway Transmission Expansion Program at PacifiCorp.
- Emissions control equipment totaling $372 million.
- The development and construction of wind-powered generating facilities totaling $250 million, including 127 MW PacifiCorp placed in service in September 2009 and construction costs for PacifiCorp's 111-MW Dunlap Ranch wind-powered generating facility.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling $1.430 billion.

Additionally, capital expenditures for the years ended December 31, 2011, 2010 and 2009 include costs related to Kern River's expansion projects totaling $174 million, $129 million and $65 million, respectively. The 2010 Expansion project was placed in service in April 2010 and added 145,000 Dth per day of capacity. The Apex Expansion project was placed in service in October 2011 and added 266,000 Dth per day of capacity. The remaining amounts are for ongoing investments in distribution and other infrastructure needed at the other platforms to serve existing and expected demand.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2011 were $(589) million. Uses of cash totaled $1.924 billion and consisted mainly of $1.548 billion for repayments of subsidiary debt, repayments of MEHC subordinated debt totaling $334 million, including $191 million called and repaid at par value, and net payments to noncontrolling interest totaling $24 million. Sources of cash totaled $1.335 billion and consisted of proceeds from subsidiary debt totaling $790 million and net proceeds from short-term debt totaling $545 million. Debt issuances during the year ended December 31, 2011 included the following:

- In May 2011, PacifiCorp issued $400 million of 3.85% First Mortgage Bonds due June 15, 2021. The net proceeds were used to fund capital expenditures, repay short-term debt and for general corporate purposes.
- In April 2011, Northern Natural Gas issued $200 million of 4.25% Senior Notes due June 1, 2021. The net proceeds were used to partially repay its $250 million, 7.0% Senior Notes due June 1, 2011.
- In January and February 2011, Northern Powergrid (Northeast) Limited issued £119 million of notes with maturity dates ranging from 2018 to 2020 at interest rates ranging from 3.901% to 4.586% under its finance contract with the European Investment Bank.

Net cash flows from financing activities for the year ended December 31, 2010 were $(234) million. Uses of cash totaled $614 million and consisted mainly of repayments of MEHC subordinated debt totaling $281 million, including $92 million called and repaid at par value, repayments of subsidiary debt totaling $192 million, net payments to noncontrolling interests totaling $80 million and net purchases of common stock totaling $56 million. Sources of cash totaled $380 million and consisted of proceeds from subsidiary debt totaling $231 million and net proceeds from short-term debt totaling $149 million.

Net cash flows from financing activities for the year ended December 31, 2009 were $(758) million. Uses of cash totaled $2.0 billion and consisted mainly of repayments of MEHC subordinated debt totaling $734 million, net repayments of short-term debt totaling $664 million, repayments of subsidiary debt totaling $444 million, net purchases of common stock of $123 million and net payments to noncontrolling interests totaling $19 million. Sources of cash totaled $1.242 billion and consisted of proceeds from the issuance of subsidiary debt totaling $992 million and proceeds from the issuance of MEHC senior debt totaling $250 million.

2012 Long-term Debt Transactions

In February 2012, Topaz issued $850 million of the 5.75% Series A Senior Secured Notes. The principal of the notes amortize beginning September 2015 with a final maturity in September 2039. The net proceeds will be used to fund or reimburse the costs and expenses related to the development, construction and financing of the Topaz Project, including amounts that have been advanced by, or will be advanced by, MEHC for the Topaz Project. Any unused amounts will be invested or, in certain circumstances, loaned to MEHC. Topaz expects to issue approximately $430 million of additional senior secured notes contingent upon certain contractual conditions and market conditions to fund construction costs.

In January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 1, 2022 and $300 million of its 4.10% First Mortgage Bonds due February 1, 2042. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes.

The Company may from time to time seek to acquire its outstanding debt securities through cash purchases in the open market, privately negotiated transactions or otherwise. Any debt securities repurchased by the Company may be reissued or resold by the Company from time to time and will depend on prevailing market conditions, the Company's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Future Uses of Cash

The Company has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, the issuance of equity and other sources. These sources are expected to provide funds required for current operations, capital expenditures, acquisitions, investments, debt retirements and other capital requirements. The availability and terms under which each subsidiary has access to external financing depends on a variety of factors, including its credit ratings, investors' judgment of risk and conditions in the overall capital market, including the condition of the utility industry in general. Additionally, MEHC has the Berkshire Equity Commitment pursuant to which Berkshire Hathaway has agreed to purchase up to $2.0 billion of MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The Berkshire Equity Commitment expires on February 28, 2014 and may only be used for the purpose of (a) paying when due MEHC's debt obligations and (b) funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request in increments of at least $250 million pursuant to one or more drawings authorized by MEHC's Board of Directors. The funding of any such drawing will be made by means of a cash equity contribution to MEHC in exchange for additional shares of MEHC's common stock.

Capital Expenditures

The Company has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in rules and regulations, including environmental and nuclear; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items, such as pollution-control technologies, replacement generation, nuclear decommissioning, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into MEHC's energy subsidiaries' regulated retail rates.

Forecasted capital expenditures, which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ended December 31 are as follows (in millions):

	2012	2013	2014
Forecasted capital expenditures:			
Construction and other development projects	$ 2,094	$ 2,051	$ 1,959
Operating projects	1,753	1,426	1,638
Total	$ 3,847	$ 3,477	$ 3,597

Construction and other development projects consist mainly of large scale projects at MidAmerican Renewables and the Utilities.

In January 2012, MEHC acquired Topaz and its 550-MW Topaz Project in California from a subsidiary of First Solar, Inc. ("First Solar"). The Topaz Project is expected to cost approximately $2.44 billion, including all interest during construction, and will be completed in 22 blocks with an aggregate tested capacity of 586 MW. The Topaz Project expects to place 45 MW in service in 2012, 236 MW in service in 2013, 252 MW in service in 2014 and 53 MW in service in 2015. The Topaz Project is being constructed pursuant to a fixed price, date certain, turn-key engineering, procurement and construction contract with a subsidiary of First Solar.

MEHC has committed to provide Topaz with equity to fund the costs of the Topaz Project in an amount up to $2.44 billion less, among other things, the gross proceeds of long-term debt issuances (including the gross proceeds of $850 million of the 5.75% Series A Senior Secured Notes issued by Topaz in February 2012), project revenue prior to completion and the total equity contributions made by MEHC or its subsidiaries. If MEHC does not maintain a minimum credit rating from two of the following three rating agencies of at least BBB- from Standard & Poor's Ratings Services or Fitch Ratings or Baa3 from Moody's Investors Service, MEHC's obligations under the equity commitment agreement would be supported by cash collateral or a letter of credit issued by a financial institution that meets certain minimum criteria specified in the financing documents. Upon reaching the final commercial operation date of the Topaz Project, MEHC will have no further obligation to make any equity contribution and any unused equity contribution obligations will be canceled.

The Utilities anticipate costs for emissions control equipment will total $1.361 billion between 2012 and 2014, which includes equipment to meet anticipated air quality and visibility targets, including the reduction of sulfur dioxide, nitrogen oxides and particulate matter emissions. This estimate includes the installation of new or the replacement of existing emissions control equipment at a number of units at several of the Utilities coal-fueled generating facilities.

PacifiCorp anticipates costs for transmission projects will total $1.205 billion between 2012 and 2014. The costs include PacifiCorp's Energy Gateway Transmission Expansion Program totaling $905 million, including the following estimated costs:

- $245 million for the 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley. A 65-mile segment of the Mona to Oquirrh transmission project will be a single-circuit 500-kV transmission line, while the remaining 35-mile segment will be a double-circuit 345-kV transmission line. The project is estimated to cost $374 million and is expected to be placed in service in 2013.
- $288 million for the 160-mile single-circuit 345-kV transmission line being built between the Sigurd Substation in central Utah and the Red Butte Substation in southwest Utah. The Sigurd to Red Butte project is estimated to cost $380 million and is expected to be placed in service in 2015.
- $372 million for other segments associated with the Energy Gateway Transmission Expansion Program that are expected to be placed in service through 2021, depending on siting, permitting and construction schedules.

PacifiCorp anticipates costs for additional natural gas-fueled generating facilities will total $893 million between 2012 and 2014, which includes the construction of the Lake Side 2 natural gas-fueled generating facility that is expected to be placed in service in 2014, and the initial development and construction of another combined-cycle combustion turbine natural gas-fueled generating facility planned to be placed in service in 2016.

MidAmerican Energy is constructing 407 MW (nominal ratings) of wind-powered generation that it expects to place in service in 2012. Total costs are estimated to be $680 million, with the payment of over half of those costs deferred until the fourth quarter of 2015.

MidAmerican Renewables anticipates costs for the Bishop Hill II Project, an 81 MW wind-powered generating facility, will total $164 million in 2012. The Bishop Hill II Project is expected to be placed in service in 2012. Definitive agreements have been executed, subject to customary closing conditions, and the acquisition is expected to close in March 2012.

In December 2011, MidAmerican Energy received approval from the MISO for several MVPs located in Iowa and Illinois totaling approximately $550 million in capital expenditures, the bulk of which will be incurred in 2014-2017. As of December 31, 2011, MidAmerican Energy had not contractually committed to material amounts for these projects.

Separately, in July 2011, the FERC issued Order No. 1000, which addresses transmission planning and cost allocation issues. Among other things, Order No. 1000 removes the federal right of first refusal for certain new transmission investments approved by the MISO following its compliance filing with the FERC. MidAmerican Energy believes its approved MVPs are not subject to the loss of right of first refusal unless the projects are re-evaluated and changed under a three-year review process required by the FERC. MidAmerican Energy continues to actively review other impacts of Order No. 1000.

Capital expenditures related to operating projects consist of routine expenditures for distribution, generation, mining and other infrastructure needed to serve existing and expected demand.

Equity Investments

ETT, a company owned equally by subsidiaries of American Electric Power Company, Inc. and MEHC, owns and operates electric transmission assets in the ERCOT. In order to fund ETT's ongoing transmission investment, MEHC expects to make equity contributions to ETT during 2012, 2013 and 2014 of $107 million, $58 million and $4 million, respectively.

In January 2012, MEHC, through a wholly-owned subsidiary, acquired from NRG Energy, Inc. a 49 percent interest in Agua Caliente, the owner of the 290-MW Agua Caliente Project in Arizona. The Agua Caliente Project is expected to costs approximately $1.8 billion and will be completed in 12 blocks with an aggregate tested capacity of 310 MW. The first 30-MW block of the Agua Caliente Project was placed in service in January 2012 and the Agua Caliente Project expects to place 112 additional MW in service in 2012, 136 MW in service in 2013 and 32 MW in service in 2014. The project is being constructed pursuant to a fixed price, date certain, turn-key engineering, procurement and construction contract with a subsidiary of First Solar. Construction costs are expected to be funded with equity contributions from MEHC and NRG Energy, Inc. and proceeds from a $967 million secured loan maturing in 2037 from an agency of the United States government as part of the United States Department of Energy loan guarantee program. Funding requests are submitted on a monthly basis and the approved loans accrue interest at a fixed rate based on the current average yield of comparable maturity United States Treasury rates plus a spread of 0.375%.

Pursuant to an equity funding and contribution agreement, MEHC has committed to provide Agua Caliente with funding for (a) base equity contributions of up to an aggregate amount of $303 million for the construction of the project, and (b) transmission upgrade costs. In January 2012, MEHC entered into a $303 million letter of credit facility related to its funding commitments. The equity funding and contribution agreement and the letter of credit commitment decreases as equity is contributed to the Agua Caliente Project.

Contractual Obligations

The Company has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes the Company's material contractual cash obligations as of December 31, 2011 (in millions):

	Payments Due By Periods				
	2012	2013-2014	2015-2016	2017 and After	Total
MEHC senior debt	$ 742	$ 250	$ —	$ 4,375	$ 5,367
MEHC subordinated debt	22	—	—	—	22
Subsidiary debt	434	2,043	663	10,526	13,666
Interest payments on long-term debt(1)	1,073	1,951	1,809	12,060	16,893
Short-term debt	865	—	—	—	865
Coal, electricity and natural gas contract commitments(1)	1,389	1,958	1,261	3,621	8,229
Construction commitments(1)	757	466	442	52	1,717
Operating leases and easements(1)	89	127	71	366	653
Maintenance, service and other contracts(1)	192	172	51	142	557
Total contractual cash obligations	$ 5,563	$ 6,967	$ 4,297	$ 31,142	$ 47,969

(1) Not reflected on the Consolidated Balance Sheets.

The Company has other types of commitments that arise primarily from unused lines of credit, letters of credit or relate to construction and other development costs (Liquidity and Capital Resources included within this Item 7), asset retirement obligations (Note 13) and uncertain tax positions (Note 15) which have not been included in the above table because the amount and timing of the cash payments are not certain. Additionally, refer to Note 23 for commitments that arose subsequent to December 31, 2011 and that are not included in the above table. Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

MEHC's regulated subsidiaries and certain affiliates are subject to comprehensive regulation. In addition to the discussion contained herein regarding regulatory matters, refer to Item 1 of this Form 10-K for further discussion regarding the general regulatory framework at MEHC's regulated subsidiaries.

PacifiCorp

Utah

In March 2009, PacifiCorp filed for an ECAM with the UPSC. The filing recommended that the UPSC adopt the mechanism to recover the difference between base net power costs set in the next Utah general rate case and actual net power costs. In July 2010, the UPSC issued an order approving a stipulation that would establish deferred accounts for both net power costs and REC revenues in excess of the levels currently included in rates, subject to the UPSC's final determination of the ratemaking treatment of the deferrals. In December 2010, the UPSC approved a separate stipulation that provided a $3 million monthly credit to customers effective January 1, 2011 to be applied toward the UPSC's final decision. In March 2011, the UPSC issued its final order approving the use of an EBA in Utah to begin at the conclusion of the general rate case described below. Under the EBA, which has been established as a four year pilot program, 70% of any difference between actual net power costs incurred and the amount of net power costs recovered through base rates are deferred during the calendar year. PacifiCorp must then file by March 15 of the following year to initiate collection or refund of the deferred balance. In April 2011, PacifiCorp filed a petition with the UPSC for clarification and reconsideration of certain aspects of the EBA order, including reconsideration of the UPSC's decision to exclude financial swaps from the EBA, which was granted in May 2011.

In January 2011, PacifiCorp filed a general rate case with the UPSC requesting a rate increase of $232 million, or an average price increase of 14%. In June 2011, PacifiCorp filed its rebuttal testimony with the UPSC reducing the requested rate increase to $188 million, or an average price increase of 11%. In July 2011, PacifiCorp filed a settlement with the UPSC, which was approved by the UPSC in August 2011 and resulted in a $117 million rate increase, or an average price increase of 7% effective September 21, 2011. The settlement resolved all major dockets outstanding before the UPSC. Under the terms of the settlement, financial swaps are included in the EBA and a collaborative process with Utah stakeholders may result in future modifications to PacifiCorp's risk management and hedging policies. The settlement also concluded the ratemaking treatment of deferred accounts for net power costs and estimated sales of RECs in excess of the levels included in rates since the 2009 general rate case. The settlement provides for $60 million of net power costs in excess of amounts included in base rates to be recovered from Utah customers over a three-year period beginning June 1, 2012, without carrying charges. The settlement also provides for a $33 million credit to customers related to sales of RECs that substantially occurred in prior years and that will be credited to Utah customers over a period of approximately nine months beginning September 21, 2011, plus carrying charges. The settlement also establishes a balancing account for prospective REC sales. The settlement stipulation defers decisions regarding the ratemaking treatment associated with the Klamath hydroelectric system's four mainstem dams and relicensing and settlement costs as described in Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

In November 2011, PacifiCorp filed with the UPSC to decrease its DSM cost recovery tariff in Utah by 1% of a customer's eligible monthly charges. In January 2012, the UPSC approved an all-party stipulation to reduce the DSM surcharge by 0.4% effective February 1, 2012. In addition, approximately $5 million will be credited to customers over a one-year period beginning June 1, 2012.

In February 2012, PacifiCorp filed a general rate case with the UPSC requesting a rate increase of $172 million, or an average price increase of 10%.

Oregon

In March 2011, PacifiCorp made its initial filing for the annual TAM with the OPUC for an annual increase of $62 million to recover the anticipated net power costs forecasted for calendar year 2012. In July 2011, PacifiCorp filed updated net power costs, reflecting an increase in the overall request to $63 million. In August 2011, PacifiCorp filed its surrebuttal testimony in the TAM proceeding decreasing the overall request to $59 million due to a reduction in forecasted net power costs. In September 2011, PacifiCorp reached a settlement with several parties, including the OPUC staff, to reduce the requested increase to $51 million, or an average price increase of 4%, subject to final net power cost updates in November 2011. In November 2011, the OPUC approved the overall rate increase of $51 million, or an average price increase of 4%. The new rates were effective January 1, 2012.

In October 2010, PacifiCorp filed its 2009 tax report under SB 408. In January 2011, PacifiCorp entered into a stipulation with the OPUC staff and the Citizens' Utility Board of Oregon, whereby PacifiCorp, the OPUC staff and the Citizens' Utility Board of Oregon agreed to a surcharge of $13 million, plus interest. In April 2011, the OPUC issued an order adopting the stipulation without significant modification. The $13 million, plus interest, was recorded in earnings in the second quarter of 2011 and is being collected over a one-year period that began in June 2011.

In May 2011, Oregon Senate Bill 967 ("SB 967") was enacted into law. SB 967 repealed and replaced SB 408, and as a result, PacifiCorp will no longer be required to file tax reports under SB 408. Among other matters, SB 967 directs the OPUC to consider the income tax component of rates when conducting ratemaking proceedings. The enactment of SB 967 did not impact PacifiCorp's consolidated financial results.

Wyoming

In April 2010, PacifiCorp filed an application with the WPSC requesting approval of a new ECAM to replace the existing PCAM. The PCAM concluded with the final deferral of net power costs in November 2010 and collection through March 2012. In February 2011, the WPSC issued an order approving an ECAM effective December 1, 2010, under which 70% of any difference between actual net power costs incurred and the amount of net power costs recovered through base rates, subject to certain other adjustments, are deferred as incurred during the calendar year. PacifiCorp must then file by March 15 of the following year to initiate collection or refund of the deferred balance beginning June 1.

In November 2010, PacifiCorp filed a general rate case with the WPSC requesting a rate increase of $98 million, or an average price increase of 17%. In May 2011, PacifiCorp filed its rebuttal testimony with the WPSC reducing the requested rate increase to $80 million. In June 2011, the WPSC approved a multi-party stipulation resulting in an annual rate increase of $62 million, or an average price increase of 11%. The stipulation also established a surcredit and a balancing account to pass on to or collect from customers any difference between the amount of the REC sales established in the surcredit and actual REC sales. The surcredit will be established annually based on PacifiCorp's forecasted REC sales, and the difference between the surcredit and actual REC sales will be tracked in the balancing account. For 2011, the surcredit was set at $17 million, or a 3% reduction. The rates were effective September 22, 2011.

In February 2011, PacifiCorp filed its final PCAM application with the WPSC requesting recovery of $16 million in deferred net power costs over the 12-month period ending March 31, 2012. PacifiCorp requested and received approval from the WPSC to implement an $11 million interim rate increase over the $5 million reflected in the tariff to be effective from April 1, 2011 until the WPSC issues a final order. In September 2011, PacifiCorp reached an agreement with intervening parties and filed a stipulation with the WPSC to recover $14 million in deferred net power costs. In October 2011, the WPSC approved the stipulation with an effective date of November 1, 2011.

In December 2011, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $63 million, or an average price increase of 10%. If approved by the WPSC, the new rates are expected to be effective October 9, 2012.

Washington

In May 2010, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $57 million, or an average price increase of 21%. In November 2010, the requested annual increase was reduced to $49 million, or an average price increase of 18%. In March 2011, the WUTC issued a final order and clarification letter approving an annual increase of $33 million, or an average price increase of 12%, reduced in the first year by a customer bill credit of $5 million, or 2%, related to the sale of RECs expected during the twelve-month period ended March 31, 2012, as well as requiring PacifiCorp to submit additional information to the WUTC regarding the sales of RECs. The new rates were effective in April 2011. Although both PacifiCorp and the WUTC staff filed petitions for reconsideration of various items on the final order, the WUTC denied the petitions for reconsideration. In May 2011 PacifiCorp submitted to the WUTC the additional information required by the March 2011 order regarding PacifiCorp's proceeds from sales of RECs for the period January 1, 2009 forward and a detailed proposal for a tracking mechanism for proceeds of RECs. Intervening parties and WUTC staff are proposing that PacifiCorp refund to customers the amount of REC sales in excess of the amount included in base rates since January 1, 2009. Initial and reply briefs from all parties were filed in November 2011. Oral arguments were held before the WUTC in January 2012, and an order is expected during the first quarter of 2012.

In July 2011, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $13 million, or an average price increase of 4%, with an effective date no later than June 1, 2012. In February 2012, the parties to the proceeding filed a settlement agreement with the WUTC reflecting an annual increase of $5 million, or an average price increase of 2%. A hearing on the settlement agreement is scheduled for March 2012.

Idaho

In May 2010, PacifiCorp filed a general rate case with the IPUC requesting an annual increase of $28 million, or an average price increase of 14%. In November 2010, the requested annual increase was reduced to $25 million, or an average price increase of 12%. In December 2010, the IPUC issued an interim order approving an annual increase of $14 million, or an average price increase of 7% with an effective date of December 28, 2010. In February 2011, the IPUC issued its final order with no revisions to the December 2010 increase. In March 2011, PacifiCorp petitioned the IPUC seeking reconsideration or rehearing on certain aspects of the order, including the IPUC's conclusion that 27% of PacifiCorp's Populus to Terminal transmission line investment is not currently used and useful and should be carried as plant held for future use. The Idaho-allocated share of 27% of the investment is approximately $13 million. In April 2011, the IPUC issued an order, accepting in part and rejecting in part, PacifiCorp's motion for reconsideration, resulting in no significant changes to the IPUC's initial order. In May 2011, PacifiCorp filed an appeal of the Populus to Terminal decision to the Idaho Supreme Court requesting a determination on the legality of the IPUC's decision to exclude 27% of the Populus to Terminal line as a result of its conclusion that the line is not fully used and useful. As a result of the general rate case settlement process discussed below, PacifiCorp joined in a motion filed with the Idaho Supreme Court in October 2011, to stay the procedural schedule associated with the appeal until January 30, 2012, and the Idaho Supreme Court granted the motion. The matter was settled in the general rate case described below and the appeal was dismissed.

In May 2011, PacifiCorp filed a general rate case with the IPUC requesting an annual increase of $33 million, or an average price increase of 15%. In October 2011, a settlement was reached with the majority of parties in the case providing for a two-year agreement to increase rates by $17 million each year effective January 1, 2012 and January 1, 2013, representing average price increases of 8% and 7%, respectively. The settlement also resolved the dispute over the 27% of PacifiCorp's Populus to Terminal investment, providing for recovery of PacifiCorp's investment beginning on or after January 1, 2014. In January 2012, PacifiCorp received an order from the IPUC approving the settlement.

In February 2011, PacifiCorp filed an ECAM application with the IPUC requesting recovery of $13 million in deferred net power costs. In March 2011, the IPUC issued an order approving recovery of $10 million beginning April 1, 2011 and the remaining $3 million beginning in 2012.

In February 2012, PacifiCorp filed an ECAM application with the IPUC requesting recovery of $18 million in deferred net power costs through an increase to the current ECAM surcharge rate established in 2011. If approved, the new rates will be effective April 1, 2012.

MidAmerican Energy

On February 21, 2012, MidAmerican Energy filed an application with the IUB for an interim and final increase in Iowa retail electric rates in the form of two adjustment clauses to be added to customers' bills. The requested adjustment clauses and a modification to current revenue sharing provisions are consistent with a November 2011 settlement agreement between MidAmerican Energy and the OCA, in which the parties agree to support the proposed changes. The adjustment clauses would recover anticipated increases in retail coal and coal transportation costs and environmental control expenditures subject to an aggregate maximum of $39 million, or 3.4%, for 2012 and an additional $37 million for an aggregate maximum of $76 million for 2013, or a 3.2% increase from 2012. The requested modification to the existing revenue sharing provisions provides for MidAmerican Energy to share with its customers 20% of revenue associated with Iowa electric returns on equity between 10% and 10.5%, 50% of revenue associated with Iowa electric returns on equity between 10.5% and 11.75%, 75% of revenue associated with Iowa electric returns on equity between 11.75% and 13.0% and 83.3% of revenue associated with Iowa electric returns on equity above 13.0%. Such shared amounts would reduce MidAmerican Energy's investment in the Walter Scott, Jr. Energy Center Unit 4. There would be no revenue sharing for Iowa electric returns on equity below 10%. Pursuant to the settlement agreement, MidAmerican Energy is not precluded from seeking interim rate relief in 2013.

Kern River

In December 2009, the FERC issued an order establishing revised rates for the period of Kern River's current long-term contracts ("Period One rates") and required that rates be established based on a levelized rate design for eligible customers to elect to take service following the expiration of their current contracts ("Period Two rates"). The FERC set all other issues related to Period Two rates for hearing. In November 2010, the FERC issued an order that denied all requests for rehearing related to Period One rates from the FERC's December 2009 order and established that Kern River is entitled to base its Period Two rates on a 100% equity capital structure. In January 2011, Kern River filed a motion for clarification on certain depreciation issues with the FERC.

In July 2011, the FERC issued its order substantially adopting the presiding administrative law judge's initial decision issued in April 2011 regarding Kern River's Period Two rates. According to the decisions, Period Two rates should be based on a return on equity of 11.55%, a capital structure of 100% and a levelization period that coincides with a contract length of 10 or 15 years. Kern River has a regulatory asset approved by the FERC associated with compressor engines and general plant replacements that can be recovered in a future rate case and was not incorporated into Period Two rates at this time. Kern River, as well as others, requested rehearing and clarification of the FERC's July 2011 order on a majority of the issues. Kern River filed tariffs in compliance with the FERC's order in August 2011 and, following an order on compliance, again in September 2011. In late September 2011, the FERC issued a second order on compliance, accepting Kern River's tariff filing. The FERC has not yet responded to the requests for rehearing and clarification of the July 2011 order.

ETT

In December 2011, ETT filed its second Interim Transmission Cost of Service ("TCOS") of 2011 at the PUCT. The application was based on a test year ending October 31, 2011. The filing requested an increase in total transmission invested capital of $82 million and a total revenue requirement increase of $11 million. In January 2012, the PUCT staff recommended approval of ETT's second interim TCOS filing of 2011. ETT, along with PUCT staff, filed a joint proposed notice of approval. On January 31, 2012, the administrative law judge signed the final order making the new rates effective.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, RPS, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state, local and international agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and the Company is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. The Company believes it is in material compliance with all applicable laws and regulations. Refer to "Liquidity and Capital Resources" for discussion of the Company's forecasted environmental-related capital expenditures.

Clean Air Standards

The Clean Air Act is a federal law administered by the EPA that provides a framework for protecting and improving the nation's air quality and controlling sources of air emissions. The implementation of new standards is generally outlined in SIPs, which are a collection of regulations, programs and policies to be followed. SIPs vary by state and are subject to public hearings and EPA approval. Some states may adopt additional or more stringent requirements than those implemented by the EPA. The major Clean Air Act programs most directly affecting the Company's operations, are described below.

National Ambient Air Quality Standards

Under the authority of the Clean Air Act, the EPA sets minimum national ambient air quality standards for six principal pollutants, consisting of carbon monoxide, lead, nitrogen oxides, particulate matter, ozone and sulfur dioxide, considered harmful to public health and the environment. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area that are determined to contribute to the nonattainment are required to reduce emissions. Most air quality standards require measurement over a defined period of time to determine the average concentration of the pollutant present. Currently, air quality monitoring data indicates that all counties where MidAmerican Energy's major emission sources are located are in attainment of the current national ambient air quality standards.

In December 2009, the EPA designated the Utah counties of Davis and Salt Lake, as well as portions of Box Elder, Cache, Tooele, Utah and Weber counties, to be in nonattainment of the fine particulate matter standard. This designation has the potential to impact PacifiCorp's Lake Side and Gadsby generating facilities, depending on the requirements to be established in the Utah SIP. The impact, if any, on PacifiCorp's generating facilities is not anticipated to be significant.

In January 2010, the EPA proposed a rule to strengthen the national ambient air quality standard for ground level ozone. The proposed rule arose out of legal challenges claiming that a March 2008 rule that reduced the standard from 80 parts per billion to 75 parts per billion was not strict enough. The new rule proposed a standard between 60 and 70 parts per billion. In September 2011, the President requested that the EPA withdraw the proposed ozone standard and allow the review of the standards to proceed through the regularly scheduled review in 2013. The EPA is, therefore, proceeding with implementation of the March 2008 ozone standards and, in December 2011, issued its response to states' recommendations on area attainment designations. Part of the EPA's response recommended that the Upper Green River Basin Area in Wyoming, including all of Sublette and portions of Lincoln and Sweetwater Counties, be designated as nonattainment for the March 2008 ozone standard. While PacifiCorp's Jim Bridger plant is located in Sweetwater County, it is not in the portion proposed for designation as nonattainment and is not expected to be impacted by the proposed designation. The EPA also published a proposed consent decree in the Federal Register in December 2011, requiring it to sign final designations for the March 2008 ozone standard by May 31, 2012.

In January 2010, the EPA finalized a one-hour air quality standard for nitrogen dioxide at 0.10 part per million. The EPA published final designations that are effective February 29, 2012, indicating that based on air quality monitoring data, all areas of the country are designated as "unclassifiable/attainment" for the 2010 nitrogen dioxide national ambient air quality standard.

In June 2010, the EPA finalized a new national ambient air quality standard for sulfur dioxide. Under the new rule, the existing 24-hour and annual standards for sulfur dioxide, which were 140 parts per billion measured over 24 hours and 30 parts per billion measured over an entire year, were replaced with a new one-hour standard of 75 parts per billion. The new rule will utilize a three-year average to determine attainment. The rule will utilize source modeling, in addition to the installation of ambient monitors where sulfur dioxide emissions impact populated areas, with new monitors required to be placed in service no later than January 2013. Attainment designations are due by June 2012, with SIPs due by 2014 and final attainment demonstrations by August 2017.

As new, more stringent standards are adopted, the number of counties designated as nonattainment areas is likely to increase. Businesses operating in newly designated nonattainment counties could face increased regulation and costs to monitor or reduce emissions. For instance, existing major emissions sources may have to install reasonably available control technologies to achieve certain reductions in emissions and undertake additional monitoring, recordkeeping and reporting. The construction or modification of facilities that are sources of emissions could become more difficult in nonattainment areas. Until additional monitoring and modeling is conducted, the impacts on the Company cannot be determined.

Mercury and Air Toxics Standards

The Clean Air Mercury Rule ("CAMR"), issued by the EPA in March 2005, was the United States' first attempt to regulate mercury emissions from coal-fueled generating facilities through the use of a market-based cap-and-trade system. The CAMR, which mandated emissions reductions of approximately 70% by 2018, was overturned by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") in February 2008. In March 2011, the EPA proposed a new rule that would require coal-fueled generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of "Maximum Achievable Control Technology" standards rather than a cap-and-trade system. The final rule, MATS, was released by the EPA in December 2011 and published in the Federal Register on February 16, 2012, and requires that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards within three years after the rule is final, with individual sources granted an additional year to complete installation of controls if approved by the permitting authority. While the final MATS continues to be reviewed by the Company, the Company believes that its emissions reduction projects completed to date or currently permitted or planned for installation, including scrubbers, baghouses and electrostatic precipitators are consistent with the EPA's MATS and will support the Company's ability to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants. The Company will be required to take additional actions to reduce mercury emissions through the installation of controls or use of sorbent injection at certain of its coal-fueled generating facilities and otherwise comply with the final rule's standards. The Company is evaluating whether or not to close certain units. Incremental costs to install and maintain mercury emissions control equipment at the Company's coal-fueled generating facilities and any requirements to shut down generating facilities will increase the cost of providing service to customers.

Clean Air Interstate Rule, Clean Air Transport Rule and Cross-State Air Pollution Rule

The EPA promulgated the CAIR in March 2005 to reduce emissions of nitrogen oxides and sulfur dioxide, precursors of ozone and particulate matter, from down-wind sources. The CAIR required states in the eastern United States, including Iowa, to reduce emissions by implementing a plan based on a market-based cap-and-trade system, emissions reductions, or both. The CAIR created separate trading programs for nitrogen oxides and sulfur dioxide emissions credits. The nitrogen oxides and sulfur dioxide emissions reductions were planned to be accomplished in two phases, in 2009-2010 and 2015.

In July 2008, a three-judge panel of the D.C. Circuit issued a unanimous decision vacating the CAIR. In December 2008, the D.C. Circuit issued an opinion remanding, without vacating, the CAIR back to the EPA to conduct proceedings to fix the flaws in CAIR consistent with the D.C. Circuit's July 2008 ruling.

In July 2010, the EPA proposed the Clean Air Transport Rule ("Transport Rule"), a replacement of the CAIR, which required electric generating units in 31 states and the District of Columbia to reduce emissions of nitrogen oxides and sulfur dioxide on a state-by-state basis in accordance with each state's modeled contribution to nonattainment of the ozone and fine particulate standards in downwind states. The emissions reductions required under the Transport Rule were intended only to resolve transported emissions and not to resolve air quality issues in the states where the generation is located. The Transport Rule's emissions reduction requirements were proposed to take place in two phases, with the first phase beginning in 2012 and the second phase beginning in 2014. By 2014, the Transport Rule and other state and EPA actions would reduce power plant nitrogen oxides emissions by 52% and sulfur dioxide emissions by 71% from 2005 levels in covered states. The EPA proposed to administer separate trading programs for nitrogen oxides and sulfur dioxide credits under the Transport Rule. Facilities were required to comply with the CAIR until the Transport Rule became effective.

In July 2011, the EPA issued the final Transport Rule, renamed the Cross-State Air Pollution Rule ("CSAPR"), to address interstate transport of sulfur dioxide and nitrogen oxides emissions in 27 eastern and Midwestern states. Upon full implementation in 2014, the CSAPR will reduce total sulfur dioxide emissions by 73% and nitrogen oxides emissions by 54% at electric generating facilities in the 27-state region as compared to 2005 levels. MidAmerican Energy's coal-fueled generating facilities in Iowa are impacted by and required to make emissions reductions and otherwise comply with the CSAPR. In addition to issuing the final rule, the EPA issued a supplemental notice of proposed rulemaking to include Iowa and five other states in the ozone season nitrogen oxides emissions reduction requirements. The ozone season supplemental proposal was finalized in December 2011, and includes Iowa and four other states in the CSAPR ozone season nitrogen oxide emission reduction requirements. While MidAmerican Energy operates natural gas-fueled generating facilities in Iowa and MidAmerican Renewables operates natural gas-fueled generating facilities within the states of Illinois, Texas and New York, which are in the CSAPR region, no significant impact is expected on those generating facilities.

In December 2011, the D.C. Circuit issued a stay on the implementation of the CSAPR pending consideration of several petitions for review before the court. The court held that the CAIR should be administered pending the resolution of the pending petitions for review.

MidAmerican Energy is currently complying with the CAIR and has installed or is in the process of installing emissions controls at some of its generating facilities to comply with the CAIR and may purchase nitrogen oxides and sulfur dioxide emissions credits for emissions in excess of allocated allowances. The cost of these credits is subject to market conditions at the time of purchase and historically has not been material. The full impact of the CSAPR, or the CAIR, cannot be determined until the outcome of the litigation pending in the D.C. Circuit or the stay of the CSAPR is lifted. It is possible that the existing CAIR or the CSAPR may be replaced with more stringent requirements to reduce nitrogen oxides and sulfur dioxide emissions and that these requirements could be extended to the western United States through regulation or legislation such as a multi-pollutant emissions reduction bill.

MidAmerican Renewables' natural gas generating facilities in Texas, Illinois and New York are also subject to the CAIR until the CSAPR is adopted. However, the provisions are not anticipated to have a material impact on the Company. PacifiCorp's generating facilities are not subject to the CAIR or the CSAPR.

Regional Haze

The EPA has initiated a regional haze program intended to improve visibility in designated federally protected areas ("Class I areas"). Some of PacifiCorp's coal-fueled generating facilities in Utah and Wyoming and MidAmerican Energy's coal-fueled generating facilities meet the threshold applicability criteria to be eligible units under the Clean Air Visibility Rules. In accordance with the federal requirements, states were required to submit SIPs by December 2007 to demonstrate reasonable progress towards achieving natural visibility conditions in Class I areas by requiring emissions controls, known as best available retrofit technology, on sources constructed between 1962 and 1977 with emissions that are anticipated to cause or contribute to impairment of visibility. Utah submitted its most recent regional haze SIP amendments in 2011 and suggested that the emissions reduction projects planned by PacifiCorp are sufficient to meet its initial emissions reduction requirements. In September 2011, the Company received a Section 114 request for information from the EPA Region VIII requiring the Company to submit a five-factor best available retrofit technology analysis for PacifiCorp's Hunter Units 1 and 2 and the Huntington generating facility in Utah within 30 days based on the EPA's assertion that Utah failed to submit such an analysis. The Company responded to the request in November 2011 and indicated it would work with the Utah Division of Air Quality to complete the requested analysis which, based on a schedule proposed by Utah to the EPA, will be part of a process to conclude with a submittal to the EPA in February 2013. Wyoming submitted its regional haze SIP to the EPA in January 2011. The EPA is currently under a consent decree to issue a proposed decision on the Wyoming SIP by May 15, 2012, and a final decision by October 15, 2012. PacifiCorp believes that its planned emissions reduction projects will satisfy the regional haze requirements in Utah and Wyoming. It is possible that additional controls may be required after the respective SIPs have been considered by the EPA or that the timing of installation of planned controls could change.

The EPA's rejection of regional haze SIPs based on the state's selection of less stringent controls than the EPA believes are warranted has resulted in lawsuits being filed by states and affected entities. Cases are pending before the Tenth Circuit Court of Appeals by New Mexico and Oklahoma and additional cases are likely to be filed.

In December 2011, the EPA proposed to accept the emission reductions made by states impacted by the CSAPR, including Iowa, as meeting the requirements of the regional haze program. If the EPA finalizes the proposal, no further emission reductions are expected from MidAmerican Energy's coal-fueled generating facilities for purposes of meeting the regional haze requirements.

New Source Review

Under existing New Source Review ("NSR") provisions of the Clean Air Act, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory agency prior to (a) beginning construction of a new major stationary source of a regulated pollutant or (b) making a physical or operational change to an existing stationary source of such pollutants that increases certain levels of emissions, unless the changes are exempt under the regulations (including routine maintenance, repair and replacement of equipment). In general, projects subject to NSR regulations require pre-construction review and permitting under the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act. Under the PSD program, a project that emits threshold levels of regulated pollutants must undergo an analysis to determine the best available control technology and evaluate the most effective emissions controls after consideration of a number of factors. Violations of NSR regulations, which may be alleged by the EPA, states, environmental groups and others, potentially subject a company to material fines and other sanctions and remedies, including installation of enhanced pollution controls and funding of supplemental environmental projects.

Numerous changes have been proposed to the NSR rules and regulations over the last several years. In addition to the proposed changes, differing interpretations by the EPA and the courts create risk and uncertainty for entities when seeking permits for new projects and installing emissions controls at existing facilities under NSR requirements. The Company monitors these changes and interpretations to ensure permitting activities are conducted in accordance with the applicable requirements.

As part of an industry-wide investigation to assess compliance with the NSR and PSD provisions, the EPA has requested information and supporting documentation from numerous utilities regarding their capital projects for various coal-fueled generating facilities. A NSR enforcement case against an unrelated utility has been decided by the United States Supreme Court, holding that an increase in the annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. Between 2001 and 2003, PacifiCorp and MidAmerican Energy responded to requests for information relating to their capital projects at their coal-fueled generating facilities. PacifiCorp engaged in periodic discussions with the EPA over several years regarding PacifiCorp's historical projects and their compliance with NSR and PSD provisions. In September 2011, PacifiCorp received a letter from the EPA concluding these discussions. PacifiCorp cannot predict the next steps in this process and could be required to install additional emissions controls and incur additional costs and penalties in the event it is determined that PacifiCorp's historical projects did not meet all regulatory requirements.

In October 2011, MidAmerican Energy received a request from the EPA Region VII pursuant to Section 114 of the Clean Air Act for information on its coal-fueled generating facilities to supplement the requests made in 2002 and 2003. MidAmerican Energy submitted its response to the October 2011 request in December 2011. MidAmerican Energy cannot predict the outcome of this matter at this time.

Climate Change

In April 2011, the United States House of Representatives voted 255-177 on a bill (H.R. 910) that would prevent the EPA from regulating GHG emissions. No action has been taken by the Senate on the bill. While significant measures to regulate GHG emissions at the federal level were considered by the United States Congress in 2010, comprehensive climate change legislation has not been adopted. International discussions regarding climate change continue to be held periodically, but agreement has not been reached on how nations will address future climate change commitments upon the expiration of the Kyoto Protocol in December 2012.

In December 2009, the EPA published its findings that GHG threaten the public health and welfare and is pursuing regulation of GHG emissions under the Clean Air Act. Additionally, in May 2010, the EPA issued the GHG "Tailoring Rule" to address permitting requirements for GHG after determining that GHG are subject to regulation and would trigger Clean Air Act permitting requirements for stationary sources beginning in January 2011. Numerous lawsuits have been filed on both the EPA's endangerment finding and the tailoring rule and are pending in the D.C. Circuit with arguments scheduled to take place in February 2012.

While the debate continues at the federal and international level over the direction of climate change policy, several states have developed or are developing state-specific laws or regional initiatives to report or mitigate GHG emissions. In addition, governmental, non-governmental and environmental organizations have become more active in pursuing climate change related litigation under existing laws.

California mandatory GHG reporting requirements began with 2008 emissions and PacifiCorp has reported its GHG emissions annually since their inception. In September 2009, the EPA issued its final rule regarding mandatory reporting of GHG ("GHG Reporting") beginning January 1, 2010. Under GHG Reporting, suppliers of fossil fuels, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG are required to submit annual reports to the EPA. PacifiCorp, MidAmerican Energy and MidAmerican Renewables are subject to this requirement and submitted their first reports prior to September 30, 2011. Northern Natural Gas and Kern River reported their combustion-related GHG emissions prior to September 30, 2011, and are required to report their GHG emissions from equipment leaks and venting by September 28, 2012. The EPA released the 2010 GHG emissions reports in January 2012.

In the absence of comprehensive climate legislation or regulation, the Company has continued to invest in lower- and non-carbon generating resources and to operate in an environmentally responsible manner. Examples of the Company's significant investments in programs and facilities that will mitigate its GHG emissions include:

- MidAmerican Energy owns the largest and PacifiCorp owns the second largest portfolio of wind-powered generating capacity in the United States among rate-regulated utilities. As of December 31, 2011, the Company owned 2,909 MW of operating wind-powered generating capacity at a total cost of $5.4 billion. MidAmerican Energy is constructing an additional 407 MW of wind-powered generation that it expects to place in service in 2012. Additionally, the Company has power purchase agreements with 858 MW of wind-powered generating capacity.
- PacifiCorp owns 1,145 MW of hydroelectric generating capacity.
- In January 2012, MEHC, through wholly-owned subsidiaries, acquired the 550-MW Topaz Project and a 49 percent interest in the 290-MW Agua Caliente Project. The electricity delivered by the Topaz Project and Agua Caliente Project is being and will be sold to PG&E and will help PG&E meet its obligations under a California state mandate to procure capacity and electricity from renewable resources.
- PacifiCorp's Energy Gateway Transmission Expansion Program represents a plan to build approximately 2,000 miles of new high-voltage transmission lines with an estimated cost exceeding $6 billion. The plan includes several transmission line segments that will: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area.

- ETT plans to construct $1.5 billion of transmission investment in support of CREZ. CREZ is a transmission plan that advances the development of over 18,000 MW of new wind-powered generation in Texas. Additionally, AEP subsidiaries have transferred to ETT the obligation to build approximately $1.7 billion of transmission projects within ERCOT. Through December 31, 2011, $1.1 billion has been spent, of which $617 million has been placed in service. ETT's transmission system included 445 miles of transmission lines and 19 substations as of December 31, 2011.
- PacifiCorp and MidAmerican Energy have offered customers a comprehensive set of DSM programs for more than 20 years. The programs assist customers to manage the timing of their usage, as well as to reduce overall energy consumption, resulting in lower utility bills.
- The Utilities have installed and upgraded emissions control equipment at certain of its coal-fueled generating facilities to reduce emissions of sulfur dioxide and nitrogen oxides.
- MEHC holds a 10% interest in BYD Company Limited, which continues to make advances in applying its proprietary battery technology to electric vehicles and has also developed an energy storage system, solar power system, hybrid energy system and other green energy solutions.

The impact of potential federal, regional, state and international accords, legislation, regulation, or judicial proceedings related to climate change cannot be quantified in any meaningful range at this time. New requirements limiting GHG emissions could have a material adverse impact on the Company, the United States and the global economy. Companies and industries with higher GHG emissions, such as utilities with significant coal-fueled generating facilities, will be subject to more direct impacts and greater financial and regulatory risks. The impact is dependent on numerous factors, none of which can be meaningfully quantified at this time. These factors include, but are not limited to, the magnitude and timing of GHG emissions reduction requirements; the design of the requirements; the cost, availability and effectiveness of emissions control technology; the price, distribution method and availability of offsets and allowances used for compliance; government-imposed compliance costs; and the existence and nature of incremental cost recovery mechanisms. Examples of how new requirements may impact the Company include:

- Additional costs may be incurred to purchase required emissions allowances under any market-based cap-and-trade system in excess of allocations that are received at no cost. These purchases would be necessary until new technologies could be developed and deployed to reduce emissions or lower carbon generation is available;
- Acquiring and renewing construction and operating permits for new and existing generating facilities may be costly and difficult;
- Additional costs may be incurred to purchase and deploy new generating technologies;
- Costs may be incurred to retire existing coal-fueled generating facilities before the end of their otherwise useful lives or to convert them to burn fuels, such as natural gas or biomass, that result in lower emissions;
- Operating costs may be higher and generating unit outputs may be lower;
- Higher interest and financing costs and reduced access to capital markets may result to the extent that financial markets view climate change and GHG emissions as a business risk; and
- The Company's natural gas pipeline operations, electric transmission and retail sales may be impacted in response to changes in customer demand and requirements to reduce GHG emissions.

The impact of events or conditions caused by climate change, whether from natural processes or human activities, could vary widely, from highly localized to worldwide, and the extent to which a utility's operations may be affected is uncertain. Climate change may cause physical and financial risk through, among other things, sea level rise, changes in precipitation and extreme weather events. Consumer demand for energy may increase or decrease, based on overall changes in weather and as customers promote lower energy consumption through the continued use of energy efficiency programs or other means. Availability of resources to generate electricity, such as water for hydroelectric production and cooling purposes, may also be impacted by climate change and could influence the Company's existing and future electricity generating portfolio. These issues may have a direct impact on the costs of electricity production and increase the price customers pay or their demand for electricity.

International Accords

Under the United Nations Framework Convention on Climate Change, adopted in 1992, members of the convention meet periodically to discuss international responses to climate change. To date, the United States has not made a binding reduction commitment as a result of these international discussions.

Federal Legislation

Legislation introduced in the 112th Congress has been focused on repeal or delay of the EPA's ability to regulate GHG emissions. There is currently no federal legislation pending to regulate GHG emissions.

GHG Tailoring Rule

The EPA finalized the GHG "Tailoring Rule" in May 2010 requiring new or modified sources of GHG emissions with increases of 75,000 or more tons per year of total GHG to determine the best available control technology for their GHG emissions beginning in January 2011. New or existing major sources will also be subject to Title V operating permit requirements for GHG. Beginning July 1, 2011 through June 30, 2013, new construction projects that emit GHG emissions of at least 100,000 tons per year and modifications of existing facilities that increase GHG emissions by at least 75,000 tons per year will be subject to permitting requirements and facilities that were previously not subject to Title V permitting requirements will be required to obtain Title V permits if they emit at least 100,000 tons per year of carbon dioxide equivalents. Several legal challenges to the GHG Tailoring Rule have been filed in the D.C. Circuit. The EPA issued a GHG best available control technology guidance document in November 2010 in an effort to provide permitting authorities guidance on how to conduct a best available control technology review for GHG.

MidAmerican Energy has obtained and is in the process of obtaining permits to install emissions reduction equipment at existing generating facilities to comply with CSAPR and was required to assess the impacts of the projects on GHG emissions. A GHG emissions limit was imposed on the permits for those projects and management believes compliance with the GHG limits under these permits will not result in a material adverse impact on its operations. PacifiCorp's permitting of certain existing generating facilities to install emissions reduction equipment to comply with the Regional Haze Rules assessed the impacts of the projects on GHG emissions under the GHG Tailoring Rule. No GHG emissions limit was included in the permits. However, PacifiCorp's Lake Side 2 was subject to a best available control technology review and the permit includes a limit for carbon dioxide equivalent emissions. To date, permitting authorities implementing the GHG Tailoring Rule have included efficiency improvements to demonstrate compliance with best available control technology for GHG, as well as requiring emissions limits for GHGs in permits; as such, the impacts of the Tailoring Rule on the Company have not been material.

GHG New Source Performance Standards

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emissions reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. The EPA entered into a settlement agreement with a number of parties, including certain state governments and environmental groups, in December 2010 to promulgate emissions standards covering GHG by September 30, 2011, as amended, and issue final regulations by May 26, 2012. However, in mid-September, the EPA indicated it would not meet the September 30, 2011 deadline to promulgate the standards and it has not yet established a new schedule for issuing the proposed rules. It is unclear what standards the EPA will establish for new and modified sources or what the guidelines will be for existing sources. Until the standards are proposed and finalized, the impact on the Company cannot be determined.

Regional and State Activities

Several states have promulgated or otherwise participate in state-specific or regional laws or initiatives to report or mitigate GHG emissions. These are expected to impact PacifiCorp, MidAmerican Energy and other MEHC energy subsidiaries, and include:

- The Western Climate Initiative was established as a comprehensive regional effort to reduce GHG emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector. The Western Climate Initiative initially included the states of California, Montana, New Mexico, Oregon, Utah and Washington and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. However, only California, British Columbia and Quebec are moving forward under the initiative, with the other states focused on efforts to design, promote and implement cost-effective policies to reduce GHG emissions and create economic opportunities.
- In October 2011, the California Air Resources Board adopted a GHG cap-and-trade program with an effective date of January 1, 2012; compliance obligations will be imposed on entities beginning in 2013. In addition, California law imposes a GHG emissions performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the GHG emissions levels of a state-of-the-art combined-cycle natural gas-fueled generating facility, as well as legislation that adopts an economy-wide cap on GHG emissions to 1990 levels by 2020.

- Over the past several years, the states of California, Washington and Oregon have adopted GHG emissions performance standards for base load electrical generating resources. Under the laws in all three states, the emissions performance standards provide that emissions must not exceed 1,100 pounds of carbon dioxide per MWh. These GHG emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of five or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.
- The Washington and Oregon governors enacted legislation in May 2007 and August 2007, respectively, establishing goals for the reduction of GHG emissions in their respective states. Washington's goals seek to (a) reduce emissions to 1990 levels by 2020; (b) reduce emissions to 25% below 1990 levels by 2035; and (c) reduce emissions to 50% below 1990 levels by 2050, or 70% below Washington's forecasted emissions in 2050. Oregon's goals seek to (a) cease the growth of Oregon GHG emissions by 2010; (b) reduce GHG levels to 10% below 1990 levels by 2020; and (c) reduce GHG levels to at least 75% below 1990 levels by 2050. Each state's legislation also calls for state government to develop policy recommendations in the future to assist in the monitoring and achievement of these goals.
- In Iowa, legislation enacted in 2007 required the Iowa Climate Change Advisory Council ("ICCAC"), a 23-member group appointed by the Iowa governor, to develop scenarios designed to reduce statewide GHG emissions, including one scenario that would reduce emissions by 50% by 2050, and submit its recommendations to the legislature. The ICCAC also developed a second scenario to reduce GHG emissions by 90% with reductions in both scenarios from 2005 emissions levels. In January 2009, the ICCAC presented to the Iowa governor and legislature several policy options to consider to achieve GHG emissions reductions, including enhanced energy efficiency programs and increased renewable generation. No legislation has yet been enacted that would require GHG emissions reductions.
- In November 2007, the Iowa governor signed the Midwest Greenhouse Gas Accord and the Energy Security and Climate Stewardship Platform for the Midwest. The signatories to the platform were other Midwestern states that agreed to implement a regional cap-and-trade system for GHG emissions. Advisory group recommendations included the assessment of 2020 emissions reduction targets of 15%, 20% and 25% below 2005 levels and a 2050 target of 60% to 80% below 2005 levels. In addition, the accord calls for the participating states to collectively meet at least 2% of regional annual retail sales of electricity and natural gas through energy efficiency improvements by 2015 and continue to achieve an additional 2% in efficiency improvements every year thereafter. There has been no further progress in implementing a Midwest regional cap-and-trade program.
- The Regional Greenhouse Gas Initiative, a mandatory, market-based effort to reduce GHG emissions in ten Northeastern and Mid-Atlantic states, requires, beginning in 2009, the reduction of carbon dioxide emissions from the power sector of 10% by 2018. In May 2011, New Jersey withdrew from participation in the Regional Greenhouse Gas Initiative and in June 2011, a lawsuit filed in New York alleged that the state of New York unlawfully joined the Regional Greenhouse Gas Initiative without legislative approval.

GHG Litigation

The Company closely monitors ongoing environmental litigation. Many of the pending cases described below relate to lawsuits against industry that attempt to link GHG emissions to public or private harm. The Company believes the cases are without merit, despite decisions where United States Courts of Appeals reversed district court rulings dismissing the cases in 2009. The lower courts initially refrained from adjudicating the cases under the "political question" doctrine, because of their inherently political nature. Nevertheless, an adverse ruling in any of these cases would likely result in increased regulation of GHG emitters, including the Company's generating facilities, and financial uncertainty.

In September 2009, the United States Court of Appeals for the Second Circuit ("Second Circuit") issued its opinion in the case of *Connecticut v. American Electric Power, et al*, which remanded to the lower court a nuisance action by eight states and the City of New York against five large utility emitters of carbon dioxide. The United States District Court for the Southern District of New York ("Southern District of New York") dismissed the case in 2005, holding that the claims that GHG emissions from the defendants' coal-fueled generating facilities were causing harmful climate change and should be enjoined as a public nuisance under federal common law presented a "political question" that the court lacked jurisdiction to decide. The Second Circuit rejected this conclusion and stated the Southern District of New York was not precluded from determining the case on its merits. In December 2010, the United States Supreme Court agreed to hear the case on appeal from the Second Circuit and issued its decision in June 2011 dismissing the federal common law claim of nuisance and holding that the Clean Air Act provides a means to seek limits on emissions of carbon dioxide on power plants.

In October 2009, a three-judge panel in the United States Court of Appeals for the Fifth Circuit ("Fifth Circuit") issued its opinion in the case of *Ned Comer, et al. v. Murphy Oil USA, et al*., ("Comer I") a putative class action lawsuit against insurance, oil, coal and chemical companies, based on claims that the defendants' GHG emissions contributed to global warming that in turn caused a rise in sea levels and added to the ferocity of Hurricane Katrina, which combined to damage the plaintiff's private property, as well as public property. In 2007, the United States District Court for the Southern District of Mississippi ("Southern District of Mississippi") dismissed the case based on the lack of standing and further held that the claims were barred by the political question doctrine. In March 2010, the full court of the Fifth Circuit agreed to rehear the case; however, in May 2010, the Fifth Circuit dismissed the appeal for failure to have a quorum, resulting in the Southern District of Mississippi's decision, holding that property owners did not have standing to sue for climate change and that climate change was a political question for the United States Congress, standing as good law. The plaintiffs filed a petition asking the United States Supreme Court to direct the Fifth Circuit to reinstate the appeal and return it to the original panel. In January 2011, the United States Supreme Court denied the request, resulting in the original dismissal of the case to stand. However, on May 27, 2011, the Comer case was refiled ("Comer II") in the Southern District of Mississippi. The defendants in Comer II have filed a motion to dismiss, which is pending before the court. The Company was not a party in Comer I and is not a party in Comer II.

In October 2009, the United States District Court for the Northern District of California ("Northern District of California") granted the defendants' motions to dismiss in the case of *Native Village of Kivalina v. ExxonMobil Corporation, et al*. The plaintiffs filed their complaint in February 2008, asserting claims against 24 defendants, including electric generating companies, oil companies and a coal company, for public nuisance under state and federal common law based on the defendants' GHG emissions. MEHC was a named defendant in the Kivalina case. The Northern District of California dismissed all of the plaintiffs' federal claims, holding that the court lacked subject matter jurisdiction to hear the claims under the political question doctrine, and that the plaintiffs lacked standing to bring their claims. The Northern District of California declined to hear the state law claims and the case was dismissed without prejudice to their future presentation in an appropriate state court. In November 2009, the plaintiff's appealed the case to the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") where briefing has been completed, but the case has not yet been scheduled for oral argument. In February 2011, the Ninth Circuit stayed the case, pending the issuance of the United States Supreme Court's decision in *Connecticut v. American Electric Power, et al.* The oral arguments in Kivalina were held before the Ninth Circuit in November 2011 and the parties await the court's decision.

Renewable Portfolio Standards

The RPS described below could significantly impact the Company's consolidated financial results. Resources that meet the qualifying electricity requirements under the RPS vary from state to state. Each state's RPS requires some form of compliance reporting, and the Company can be subject to penalties in the event of noncompliance.

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The requirements are 3% of retail sales by January 1, 2012 through 2015, 9% of retail sales by January 1, 2016 through 2019 and 15% of retail sales by January 1, 2020. The WUTC has adopted final rules to implement the initiative.

In June 2007, the Oregon Renewable Energy Act ("OREA") was adopted, providing a comprehensive renewable energy policy and RPS for Oregon. Subject to certain exemptions and cost limitations established in the OREA, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least 5% in 2011 through 2014, 15% in 2015 through 2019, 20% in 2020 through 2024, and 25% in 2025 and subsequent years. As required by the OREA, the OPUC has approved an automatic adjustment clause to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy generating facilities and associated transmission costs.

In April 2011, the California governor signed into law Senate Bill 2 of the First Extraordinary Session that expanded the RPS to require all California retail sellers to procure an average of 20% of retail load from renewable resources by December 31, 2013, 25% by December 31, 2016 and 33% by December 31, 2020 and each year thereafter. In December 2011, the CPUC adopted a decision confirming that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits within the three categories of RPS-eligible resources established by the legislation that have been imposed on other California retail sellers. The CPUC is in the process of an extensive rulemaking to implement the new requirements under the legislation.

In March 2008, Utah's governor signed Utah Senate Bill 202. Among other things, this law provides that, beginning in the year 2025, 20% of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and DSM programs. Qualifying renewable energy sources can be located anywhere in the WECC areas, and renewable energy credits can be used.

Water Quality Standards

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In July 2004, the EPA established significant new technology-based performance standards for existing electric generating facilities that take in more than 50 million gallons of water per day. These rules were aimed at minimizing the adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals. In response to a legal challenge to the rule, in January 2007, the Second Circuit remanded almost all aspects of the rule to the EPA, without addressing whether companies with cooling water intake structures were required to comply with these requirements. On appeal from the Second Circuit, in April 2009, the United States Supreme Court ruled that the EPA permissibly relied on a cost-benefit analysis in setting the national performance standards regarding "best technology available for minimizing adverse environmental impact" at cooling water intake structures and in providing for cost-benefit variances from those standards as part of the §316(b) Clean Water Act Phase II regulations. The United States Supreme Court remanded the case back to the Second Circuit to conduct further proceedings consistent with its opinion.

In March 2011, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The proposed rule establishes requirements for all power generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the United States and use at least 25% of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility and all of MidAmerican Energy's coal-fueled generating facilities, except Louisa, Ottumwa and Walter Scott, Jr. Unit 4, which have water cooling towers, withdraw more than two million gallons per day of water from waters of the United States. PacifiCorp's Jim Bridger, Naughton, Gadsby, Hunter, Carbon and Huntington generating facilities currently utilize closed cycle cooling towers but withdraw more than two million gallons of water per day. The proposed rule includes impingement (i.e., when fish and other organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards to be met through average impingement mortality or intake velocity design criteria and entrainment (i.e., when organisms are drawn into the facility) standards to be determined on a case-by-case basis. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. The rule is required to be finalized by the EPA by July 2012. Assuming the final rule is issued by July 2012, PacifiCorp's and MidAmerican Energy's generating facilities impacted by the final rule will be required to complete impingement and entrainment studies in 2013. The costs of compliance with the cooling water intake structure rule cannot be determined until the rule is final and the prescribed studies are conducted. In the event that PacifiCorp's or MidAmerican Energy's existing intake structures require modification, the costs are not anticipated to be significant.

Coal Combustion Byproduct Disposal

In December 2008, an ash impoundment dike at the Tennessee Valley Authority's Kingston power plant collapsed after heavy rain, releasing a significant amount of fly ash and bottom ash, coal combustion byproducts, and water to the surrounding area. In light of this incident, federal and state officials have called for greater regulation of the storage and disposal of coal combustion byproducts. In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts, presenting two alternatives to regulation under the RCRA. Under the first option, coal combustion byproducts would be regulated as special waste under RCRA Subtitle C and the EPA would establish requirements for coal combustion byproducts from the point of generation to disposition, including the closure of disposal units. Alternatively, the EPA is considering regulation under RCRA Subtitle D under which it would establish minimum nationwide standards for the disposal of coal combustion byproducts. Under both options, surface impoundments utilized for coal combustion byproducts would have to be cleaned and closed unless they could meet more stringent regulatory requirements; in addition, more stringent requirements would be implemented for new ash landfills and expansions of existing ash landfills. PacifiCorp operates 16 surface impoundments and six landfills that contain coal combustion byproducts. MidAmerican Energy operates eight surface impoundments and four landfills that contain coal combustion byproducts. These ash impoundments and landfills may be impacted by the newly proposed regulation, particularly if the materials are regulated as hazardous or special waste under RCRA Subtitle C, and could pose significant additional costs associated with ash management and disposal activities at the Company's coal-fueled generating facilities. The public comment period closed in November 2010. The EPA has not indicated when the rule will be finalized, and the substance of the final rule is not known. The United States House of Representatives passed H.R. 2273 in October 2011, which would regulate coal combustion byproducts under RCRA Subtitle D. A Senate bill similar to the House bill has been introduced, but action has not been taken on the bill. The impact of the proposed regulations on coal combustion byproducts cannot be determined at this time; however, both PacifiCorp and MidAmerican Energy have begun developing surface impoundment and landfill compliance plan options to ensure that physical infrastructure decisions are aligned with the potential outcomes of the rulemaking.

Other

Other laws, regulations and agencies to which the Company is subject to include, but are not limited to:

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs.
- The Nuclear Waste Policy Act of 1982, under which the United States Department of Energy is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding nuclear decommissioning obligations.
- The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of mining activities.
- The FERC oversees the relicensing of existing hydroelectric systems and is also responsible for the oversight and issuance of licenses for new construction of hydroelectric systems, dam safety inspections and environmental monitoring. Refer to Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the relicensing of certain of PacifiCorp's existing hydroelectric facilities.

MEHC expects its Domestic Regulated Businesses will be allowed to recover the prudently incurred costs to comply with the environmental laws and regulations discussed above. The Company's planning efforts take into consideration the complexity of balancing factors such as: (a) pending environmental regulations and requirements to reduce emissions, address waste disposal, ensure water quality, and protect wildlife; (b) avoidance of excessive reliance on any one generation technology; (c) costs and trade-offs of various resource options including energy efficiency, demand response programs, and renewable generation; (d) state-specific energy policies, resource preferences, and economic development efforts; (e) additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system; and (f) keeping rates as affordable as possible. Due to the number of generating units impacted by environmental regulations, deferring installation of compliance-related projects is often not feasible or cost effective and places the Company at risk of not having access to necessary capital, material, and labor while attempting to perform major equipment installations in a compressed timeframe concurrent with other utilities across the country. Therefore, the Company has established installation schedules with permitting agencies that coordinate compliance timeframes with construction and tie-in of major environmental compliance projects as units are scheduled off-line for planned maintenance outages; these coordinated efforts help reduce costs associated with replacement power and maintain system reliability.

Collateral and Contingent Features

Debt and preferred securities of MEHC and certain of its subsidiaries are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of the rated company's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

MEHC and its subsidiaries have no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments, except for those discussed in Note 23 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K related to the Topaz financing. The Company's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability, but, under certain instances, must maintain sufficient covenant tests if ratings drop below a certain level. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain provisions that require certain of MEHC's subsidiaries, principally the Utilities, to maintain specific credit ratings on their unsecured debt from one or more of the three recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in the subsidiary's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2011, these subsidiary's credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2011, the Company would have been required to post $569 million of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of the Company's collateral requirements specific to the Company's derivative contracts.

In July 2010, the President signed into law the Dodd-Frank Reform Act. The Dodd-Frank Reform Act reshapes financial regulation in the United States by creating new regulators, regulating new markets and firms, and providing new enforcement powers to regulators. Virtually all major areas of the Dodd-Frank Reform Act, including collateral requirements on derivative contracts, are the subject of regulatory interpretation and implementation rules requiring rulemaking proceedings, some of which have been completed and others that are expected to be finalized in 2012.

The Company is a party to derivative contracts, including over-the-counter derivative contracts. The Dodd-Frank Reform Act provides for extensive new regulation of over-the-counter derivative contracts and certain market participants, including imposition of mandatory clearing, exchange trading, capital and margin requirements for "swap dealers" and "major swap participants." The Dodd-Frank Reform Act provides certain exemptions from these regulations for commercial end-users that use derivatives to hedge and manage the commercial risk of their businesses. Although the Company generally does not enter into over-the-counter derivative contracts for purposes unrelated to hedging of commercial risk and does not believe it will be considered a swap dealer or major swap participant, the outcome of the rulemaking proceedings cannot be predicted and, therefore, the impact of the Dodd-Frank Reform Act on the Company's consolidated financial results cannot be determined at this time.

Inflation

Historically, overall inflation and changing prices in the economies where MEHC's subsidiaries operate have not had a significant impact on the Company's consolidated financial results. In the United States, MEHC's regulated subsidiaries operate under cost-of-service based rate structures administered by various state commissions and the FERC. Under these rate structures, MEHC's regulated subsidiaries are allowed to include prudent costs in their rates, including the impact of inflation. The price control formula used by the United Kingdom Distribution Companies incorporates the rate of inflation in determining rates charged to customers. MEHC's subsidiaries attempt to minimize the potential impact of inflation on their operations by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

Off-Balance Sheet Arrangements

The Company has certain investments that are accounted for under the equity method in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Accordingly, an amount is recorded on the Company's Consolidated Balance Sheets as an equity investment and is increased or decreased for the Company's pro-rata share of earnings or losses, respectively, less any dividends from such investments.

As of December 31, 2011, the Company's investments that are accounted for under the equity method had short- and long-term debt of $1.045 billion, unused revolving credit facilities of $147 million and letters of credit outstanding of $57 million. As of December 31, 2011, the Company's pro-rata share of such short- and long-term debt was $508 million, unused revolving credit facilities was $73 million and outstanding letters of credit was $29 million. The entire amount of the Company's pro-rata share of the outstanding short- and long-term debt and unused revolving credit facilities is non-recourse to the Company. $25 million of the Company's pro-rata share of the outstanding letters of credit is recourse to the Company. Although the Company is generally not required to support debt service obligations of its equity investees, default with respect to this non-recourse short- and long-term debt could result in a loss of invested equity.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting the Company, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by the Company's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with the Company's Summary of Significant Accounting Policies included in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

The Domestic Regulated Businesses prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Domestic Regulated Businesses are required to defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates.

The Company continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition which could limit the Domestic Regulated Businesses' ability to recover their costs. Based upon this continuous evaluation, the Company believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels and is subject to change in the future. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI"). Total regulatory assets were $2.918 billion and total regulatory liabilities were $1.731 billion as of December 31, 2011. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Domestic Regulated Businesses' regulatory assets and liabilities.

Derivatives

The Company is exposed to the impact of market fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through MEHC's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. MidAmerican Energy also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for regulated and nonregulated retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. Additionally, the Company is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain. Each of the Company's business platforms has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. The Company employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities; interest rate risk; and foreign currency exchange rate risk. The Company does not hedge all of its commodity price, interest rate and foreign currency exchange rate risks, thereby exposing the unhedged portion to changes in market prices. Refer to Notes 6 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's derivative contracts.

Measurement Principles

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by the Company. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the applicable term of the Company's outstanding derivative contracts; therefore, the Company's forward price curves for those locations and periods reflect observable market quotes. As of December 31, 2011, the Company had a net derivative liability of $468 million related to contracts valued using either quoted prices or forward price curves based upon observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, the Company uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. The assumptions used in these models are critical, since any changes in assumptions could have a significant impact on the estimated fair value of the contracts. As of December 31, 2011, the Company had a net derivative asset of $23 million related to contracts where the Company uses internal models with unobservable inputs.

Classification and Recognition Methodology

Almost all of the Company's derivative contracts are probable of inclusion in the rates of its rate-regulated subsidiaries and changes in the estimated fair value of derivative contracts are generally recorded as net regulatory assets or liabilities. Accordingly, amounts are generally not recognized in earnings until the contracts are settled and the forecasted transaction has occurred. As of December 31, 2011, the Company had $400 million recorded as net regulatory assets related to derivative contracts on the Consolidated Balance Sheets. If it becomes no longer probable that a derivative contract will be included in regulated rates, the regulatory asset or liability will be written off and recognized in earnings.

Impairment of Long-Lived Assets and Goodwill

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value. The impacts of regulation are considered when evaluating the carrying value of regulated assets. Substantially all property, plant and equipment was used in regulated businesses as of December 31, 2011. For all other assets, any resulting impairment loss is reflected on the Consolidated Statements of Operations.

The estimate of cash flows arising from the future use of the asset that are used in the impairment analysis requires judgment regarding what the Company would expect to recover from the future use of the asset. Changes in judgment that could significantly alter the calculation of the fair value or the recoverable amount of the asset may result from significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset or the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect the Company's results of operations.

The Company's Consolidated Balance Sheet as of December 31, 2011 includes goodwill of acquired businesses of $4.996 billion. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31. Additionally, no indicators of impairment were identified as of December 31, 2011. A significant amount of judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, the Company incorporates current market information, as well as historical factors. Refer to Note 22 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's goodwill.

Pension and Other Postretirement Benefits

The Company sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees. The Company recognizes the funded status of its defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2011, the Company recognized a net liability totaling $794 million for the funded status of the Company's defined benefit pension and other postretirement benefit plans. As of December 31, 2011, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets and AOCI totaled $822 million and $673 million, respectively.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, expected long-term rate of return on plan assets and healthcare cost trend rates. These key assumptions are reviewed annually and modified as appropriate. The Company believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 14 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about the Company's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2011.

The Company chooses a discount rate based upon high quality debt security investment yields in effect as of the measurement date that corresponds to the expected benefit period. The pension and other postretirement benefit liabilities increase as the discount rate is reduced.

In establishing its assumption as to the expected long-term rate of return on plan assets, the Company utilizes the expected asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets. Pension and other postretirement benefits expense increases as the expected long-term rate of return on plan assets decreases. The Company regularly reviews its actual asset allocations and rebalances its investments to its targeted allocations when considered appropriate.

The Company chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate gradually declines to 5% in 2016 at which point the rate is assumed to remain constant. Refer to Note 14 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for healthcare cost trend rate sensitivity disclosures.

The key assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and the funded status. If changes were to occur for the following key assumptions, the approximate effect on the Consolidated Financial Statements would be as follows (in millions):

	Domestic Plans					
	Pension Plans		Other Postretirement Benefit Plans		United Kingdom Pension Plan	
	+0.5%	-0.5%	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2011						
Benefit Obligations:						
Discount rate	$ (103)	$ 114	$ (41)	$ 45	$ (137)	$ 157
Effect on 2011 Periodic Cost:						
Discount rate	$ (4)	$ 4	$ (2)	$ 3	$ (13)	$ 13
Expected rate of return on plan assets	(8)	8	(3)	3	(8)	8

A variety of factors affect the funded status of the plans, including asset returns, discount rates, plan changes and the Company's funding policy for each plan. Additionally, federal laws may require the Company to increase future contributions to its domestic pension plans, which may create more volatility in annual contributions than historically experienced and could have a material impact on the Company's consolidated financial results.

Income Taxes

In determining the Company's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the Company's various regulatory jurisdictions. The Company's income tax returns are subject to continuous examinations by federal, state, local and foreign income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The Company recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. Although the ultimate resolution of the Company's federal, state, local and foreign income tax examinations is uncertain, the Company believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material adverse impact on the Company's consolidated financial results. Refer to Note 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's income taxes.

The Utilities are required to pass income tax benefits related to certain property-related basis differences and other various differences on to their customers in certain state jurisdictions. These amounts were recognized as a net regulatory asset totaling $1.003 billion as of December 31, 2011 and will be included in regulated rates when the temporary differences reverse. Management believes the existing net regulatory assets are probable of inclusion in regulated rates. If it becomes no longer probable that these costs will be included in regulated rates, the related regulatory asset will be charged to net income.

The Company has not established deferred income taxes on the undistributed foreign earnings of Northern Powergrid Holdings or the related currency translation adjustment that have been determined by management to be reinvested indefinitely. The cumulative earnings were approximately $2.0 billion as of December 31, 2011. The Company periodically evaluates its capital requirements. If circumstances change in the future and a portion of Northern Powergrid Holdings' undistributed earnings were repatriated, the dividends would be subject to taxation in the United States. However, any United States income tax liability would be offset, in part, by available United States income tax credits with respect to corporate income taxes previously paid principally in the United Kingdom. Because of the availability of foreign income tax credits, it is not practicable to determine the United States income tax liability that would be recognized if such cumulative earnings were not reinvested indefinitely. The Company has established deferred income taxes on all other undistributed foreign earnings.

Revenue Recognition - Unbilled Revenue

Unbilled revenue was $474 million as of December 31, 2011. Revenue from energy business customers is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters, fixed reservation charges based on contractual quantities and rates or, in the case of the United Kingdom distribution businesses, when information is received from the national settlement system. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. The Company's significant market risks are primarily associated with commodity prices, interest rates, equity prices, foreign currency exchange rates and the extension of credit to counterparties with which the Company transacts. The following discussion addresses the significant market risks associated with the Company's business activities. Each of the Company's business platforms has established guidelines for credit risk management. Refer to Notes 2 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's contracts accounted for as derivatives.

Commodity Price Risk

The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through MEHC's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. MidAmerican Energy also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for regulated and nonregulated retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The Company does not engage in a material amount of proprietary trading activities. To mitigate a portion of its commodity price risk, the Company uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. The Company does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. The Company's exposure to commodity price risk is generally limited by its ability to include the costs in regulated rates, which is subject to regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates.

The table that follows summarizes the Company's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of $156 million and $141 million as of December 31, 2011 and 2010, respectively, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices with the contracted or expected volumes. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value - Net Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2011:			
Not designated as hedging contracts	$ (399)	$ (341)	$ (457)
Designated as hedging contracts	(46)	(7)	(85)
Total commodity derivative contracts	$ (445)	$ (348)	$ (542)
As of December 31, 2010:			
Not designated as hedging contracts	$ (565)	$ (537)	$ (593)
Designated as hedging contracts	(48)	(9)	(87)
Total commodity derivative contracts	$ (613)	$ (546)	$ (680)

The majority of the Company's commodity derivative contracts not designated as hedging contracts are recoverable from customers in regulated rates and, therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose the Company to earnings volatility. As of December 31, 2011 and 2010, a net regulatory asset of $400 million and $564 million, respectively, was recorded related to the net derivative liability of $399 million and $565 million, respectively. For the Company's commodity derivative contracts designated as hedging contracts, net unrealized gains and losses associated with interim price movements on commodity derivative contracts, to the extent the hedge is considered effective, generally do not expose the Company to earnings volatility. The settled cost of these commodity derivative contracts is generally included in regulated rates. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, natural gas or fuel are higher than what is included in regulated rates, including the impacts of adjustment mechanisms.

Interest Rate Risk

The Company is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. The Company manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, the Company's fixed-rate long-term debt does not expose the Company to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if the Company were to reacquire all or a portion of these instruments prior to their maturity. The Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate the Company's exposure to interest rate risk. The nature and amount of the Company's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 6, 9, 10, 11 and 12 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-K for additional discussion of the Company's short- and long-term debt.

As of December 31, 2011 and 2010, the Company had short- and long-term variable-rate obligations totaling $1.715 billion and $1.170 billion, respectively, that expose the Company to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to the Company's variable-rate debt as of December 31, 2011 is not hedged. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on the Company's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2011 and 2010.

Equity Price Risk

Market prices for equity securities are subject to fluctuation and consequently the amount realized in the subsequent sale of an investment may significantly differ from the reported market value. Fluctuation in the market price of a security may result from perceived changes in the underlying economic characteristics of the investee, the relative price of alternative investments and general market conditions.

As of December 31, 2011 and 2010, the Company's investment in BYD Company Limited common stock represented approximately 68% and 84%, respectively, of the total fair value of the Company's equity securities. The Company's remaining equity securities are primarily related to certain trust funds in which realized and unrealized gains and losses are recorded as net regulatory assets or liabilities since the Company expects to recover costs for these activities through regulated rates. The following table summarizes our investment in BYD Company Limited as of December 31, 2011 and 2010 and the effects of a hypothetical 30% increase and a 30% decrease in market price as of those dates. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value	Hypothetical Price Change	Estimated Fair Value after Hypothetical Change in Prices	Hypothetical Percentage Increase (Decrease) in MEHC Shareholders' Equity
As of December 31, 2011	$ 488	30% increase	$ 634	1%
		30% decrease	342	(1)
As of December 31, 2010	$ 1,182	30% increase	$ 1,537	2%
		30% decrease	827	(2)

Foreign Currency Exchange Rate Risk

MEHC's business operations and investments outside of the United States increase its risk related to fluctuations in foreign currency exchange rates primarily in relation to the British pound. MEHC's reporting currency is the United States dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from MEHC's foreign operations changes with the fluctuations of the currency in which they transact.

Northern Powergrid Holdings' functional currency is the British pound. At December 31, 2011, a 10% devaluation in the British pound to the United States dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a $270 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for Northern Powergrid Holdings of $39 million in 2011.

Credit Risk

Domestic Regulated Operations

The Utilities extend unsecured credit to other utilities, energy marketing companies, financial institutions and other market participants in conjunction with their wholesale energy supply and marketing activities. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with the counterparty.

The Utilities analyze the financial condition of each significant wholesale counterparty before entering into any transactions, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of wholesale counterparties, the Utilities enter into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed fees for delayed payments. If required, the Utilities exercise rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2011, PacifiCorp's aggregate credit exposure from wholesale activities totaled $338 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2011, $333 million, or 99%, of PacifiCorp's credit exposure was with counterparties having investment grade credit ratings by either Moody's Investor Service or Standard & Poor's Rating Services. As of December 31, 2011, $5 million, or 1%, of such credit exposure was with counterparties having externally rated "non-investment grade" credit ratings. As of December 31, 2011, four counterparties comprised $274 million, or 81%, of the aggregate credit exposure. All four counterparties are rated investment grade by Moody's Investor Service and Standard & Poor's Rating Services, and PacifiCorp is not aware of any factors that would likely result in a downgrade of the counterparties' credit ratings to below investment grade over the remaining term of transactions outstanding as of December 31, 2011.

During 2011, approximately 89% of MidAmerican Energy's electric wholesale sales revenues resulted from participation in RTOs, including the MISO and the PJM. MidAmerican Energy has potential indirect credit exposure to other market participants in these RTO markets. In the event of a default by a RTO market participant on its market-related obligations, losses are allocated among all other market participants in proportion to each participant's share of overall market activity during the period of time the loss was incurred, diversifying MidAmerican Energy's exposure to credit losses from individual participants. Transactional activities of MidAmerican Energy and other participants in organized RTO markets are governed by credit policies specified in each respective RTO's governing tariff or related business practices. Credit policies of RTO's, which have been developed through extensive stakeholder participation, generally seek to minimize potential loss in the event of a market participant default without unnecessarily inhibiting access to the marketplace. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material. As of December 31, 2011, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

Northern Natural Gas' primary customers include utilities in the upper Midwest. Kern River's primary customers are major oil and natural gas companies or affiliates of such companies, electric generating companies, energy marketing and trading companies, financial institutions and natural gas distribution utilities which provide services in Utah, Nevada and California. As a general policy, collateral is not required for receivables from creditworthy customers. Customers' financial condition and creditworthiness, as defined by the tariff, are regularly evaluated and historical losses have been minimal. In order to provide protection against credit risk, and as permitted by the separate terms of each of Northern Natural Gas' and Kern River's tariffs, the companies have required customers that lack creditworthiness to provide cash deposits, letters of credit or other security until their creditworthiness improves.

Northern Powergrid Holdings

The Distribution Companies charge fees for the use of their electrical infrastructure to supply companies and generators connected to their networks. The supply companies, which purchase electricity from generators and traders and sell the electricity to end-use customers, use the Distribution Companies' distribution networks pursuant to the multilateral "Distribution Connection and Use of System Agreement." The Distribution Companies' customers are concentrated in a small number of electricity supply businesses with RWE Npower PLC accounting for approximately 29% of distribution revenue in 2011. Ofgem has determined a framework which sets credit limits for each supply business based on its credit rating or payment history and requires them to provide credit cover if their value at risk (measured as being equivalent to 45 days usage) exceeds the credit limit. Acceptable credit typically is provided in the form of a parent company guarantee, letter of credit or an escrow account. Ofgem has indicated that, provided the Distribution Companies have implemented credit control, billing and collection in line with best practice guidelines and can demonstrate compliance with the guidelines or are able to satisfactorily explain departure from the guidelines, any bad debt losses arising from supplier default will be recovered through an increase in future allowed income. Losses incurred to date have not been material.

CalEnergy Philippines

NIA's obligations under the Casecnan project agreement is CE Casecnan's sole source of operating revenue. Because of the dependence on a single customer, any material failure of the customer to fulfill its obligations under the project agreement and any material failure of the ROP to fulfill its obligation under the performance undertaking would significantly impair the ability to meet existing and future obligations. Total operating revenue for the Casecnan project was $130 million for the year ended December 31, 2011. The Casecnan project agreement expires in December 2021.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
MidAmerican Energy Holdings Company
Des Moines, Iowa

We have audited the accompanying consolidated balance sheets of MidAmerican Energy Holdings Company and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of operations, cash flows, changes in equity, and comprehensive income for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedules listed in the Index at Item 15(a)(ii). These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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, such consolidated financial statements present fairly, in all material respects, the financial position of MidAmerican Energy Holdings Company and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 27, 2012

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Amounts in millions)

	As of December 31,	
	2011	2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 286	$ 470
Trade receivables, net	1,270	1,225
Income taxes receivable	456	396
Inventories	690	585
Derivative contracts	38	131
Investments and restricted cash and investments	51	44
Other current assets	492	501
Total current assets	3,283	3,352
Property, plant and equipment, net	34,167	31,899
Goodwill	4,996	5,025
Investments and restricted cash and investments	1,948	2,469
Regulatory assets	2,835	2,433
Derivative contracts	9	13
Other assets	480	477
Total assets	$ 47,718	$ 45,668

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2011	2010
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 989	$ 827
Accrued employee expenses	155	159
Accrued interest	326	341
Accrued property, income and other taxes	340	287
Derivative contracts	160	158
Short-term debt	865	320
Current portion of long-term debt	1,198	1,286
Other current liabilities	514	450
Total current liabilities	4,547	3,828
Regulatory liabilities	1,663	1,638
Derivative contracts	176	458
MEHC senior debt	4,621	5,371
MEHC subordinated debt	—	172
Subsidiary debt	13,253	12,662
Deferred income taxes	7,076	6,298
Other long-term liabilities	2,117	1,833
Total liabilities	33,453	32,260
Commitments and contingencies (Note 16)		
Equity:		
MEHC shareholders' equity:		
Common stock - 115 shares authorized, no par value, 75 shares issued and outstanding	—	—
Additional paid-in capital	5,423	5,427
Retained earnings	9,310	7,979
Accumulated other comprehensive loss, net	(641)	(174)
Total MEHC shareholders' equity	14,092	13,232
Noncontrolling interests	173	176
Total equity	14,265	13,408
Total liabilities and equity	$ 47,718	$ 45,668

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2011	2010	2009
Operating revenue:			
Energy	$ 10,181	$ 10,107	$ 10,167
Real estate	992	1,020	1,037
Total operating revenue	11,173	11,127	11,204
Operating costs and expenses:			
Energy:			
Cost of sales	3,648	3,890	3,904
Operating expense	2,544	2,470	2,571
Depreciation and amortization	1,329	1,262	1,238
Real estate	968	1,003	1,026
Total operating costs and expenses	8,489	8,625	8,739
Operating income	2,684	2,502	2,465
Other income (expense):			
Interest expense	(1,196)	(1,225)	(1,275)
Capitalized interest	40	54	41
Interest and dividend income	14	24	38
Other, net	51	110	146
Total other income (expense)	(1,091)	(1,037)	(1,050)
Income before income tax expense and equity income	1,593	1,465	1,415
Income tax expense	294	198	282
Equity income	53	43	55
Net income	1,352	1,310	1,188
Net income attributable to noncontrolling interests	21	72	31
Net income attributable to MEHC	$ 1,331	$ 1,238	$ 1,157

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2011	2010	2009
Cash flows from operating activities:			
Net income	$ 1,352	$ 1,310	$ 1,188
Adjustments to reconcile net income to net cash flows from operating activities:			
Loss (gain) on other items, net	50	(39)	11
Depreciation and amortization	1,341	1,276	1,256
Stock-based compensation	—	—	123
Changes in regulatory assets and liabilities	(12)	20	23
Deferred income taxes and amortization of investment tax credits	937	854	864
Other, net	(66)	(55)	(45)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(139)	(44)	17
Derivative collateral, net	(8)	(96)	81
Trading securities	—	—	499
Contributions to pension and other postretirement benefit plans, net	(133)	(139)	(82)
Accrued property, income and other taxes	(53)	(332)	(296)
Accounts payable and other liabilities	(49)	4	(67)
Net cash flows from operating activities	3,220	2,759	3,572
Cash flows from investing activities:			
Capital expenditures	(2,684)	(2,593)	(3,413)
Purchases of available-for-sale securities	(123)	(106)	(499)
Proceeds from sales of available-for-sale securities	111	100	256
Proceeds from Constellation Energy Group, Inc. 14% note	—	—	1,000
Proceeds from sales of assets and business, net	10	146	13
Equity method investments	(124)	(66)	(34)
(Increase) decrease in restricted cash and other	(6)	35	8
Net cash flows from investing activities	(2,816)	(2,484)	(2,669)
Cash flows from financing activities:			
Proceeds from MEHC senior debt	—	—	250
Repayments of MEHC subordinated debt	(334)	(281)	(734)
Proceeds from subsidiary debt	790	231	992
Repayments of subsidiary debt	(1,548)	(192)	(444)
Net proceeds from (repayments of) short-term debt	545	149	(664)
Net purchases of common stock	—	(56)	(123)
Net payments to noncontrolling interests	(24)	(80)	(19)
Other, net	(18)	(5)	(16)
Net cash flows from financing activities	(589)	(234)	(758)
Effect of exchange rate changes	1	—	4
Net change in cash and cash equivalents	(184)	41	149
Cash and cash equivalents at beginning of period	470	429	280
Cash and cash equivalents at end of period	$ 286	$ 470	$ 429

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Amounts in millions)

	MEHC Shareholders' Equity						
	Common		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss), Net	Noncontrolling Interests	Total Equity
	Shares	Stock					
Balance, December 31, 2008	75	$ —	$ 5,455	$ 5,631	$ (879)	$ 270	$ 10,477
Net income	—	—	—	1,157	—	31	1,188
Other comprehensive income	—	—	—	—	1,214	—	1,214
Stock-based compensation	—	—	123	—	—	—	123
Exercise of common stock options	1	—	25	—	—	—	25
Common stock purchases	(1)	—	(148)	—	—	—	(148)
Contributions	—	—	—	—	—	28	28
Distributions	—	—	—	—	—	(73)	(73)
Other equity transactions	—	—	(2)	—	—	11	9
Balance, December 31, 2009	75	—	5,453	6,788	335	267	12,843
Deconsolidation of Bridger Coal	—	—	—	—	—	(84)	(84)
Net income	—	—	—	1,238	—	72	1,310
Other comprehensive loss	—	—	—	—	(509)	—	(509)
Common stock purchases	—	—	(9)	(47)	—	—	(56)
Purchase of noncontrolling interest	—	—	(13)	—	—	(44)	(57)
Distributions	—	—	—	—	—	(34)	(34)
Other equity transactions	—	—	(4)	—	—	(1)	(5)
Balance, December 31, 2010	75	—	5,427	7,979	(174)	176	13,408
Net income	—	—	—	1,331	—	21	1,352
Other comprehensive loss	—	—	—	—	(467)	—	(467)
Distributions	—	—	—	—	—	(25)	(25)
Other equity transactions	—	—	(4)	—	—	1	(3)
Balance, December 31, 2011	75	$ —	$ 5,423	$ 9,310	$ (641)	$ 173	$ 14,265

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2011	2010	2009
Net income	$ 1,352	$ 1,310	$ 1,188
Other comprehensive (loss) income, net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $(10), $29 and $(45)	(30)	54	(114)
Foreign currency translation adjustment	(10)	(106)	255
Unrealized (losses) gains on available-for-sale securities, net of tax of $(279), $(318) and $709	(419)	(480)	1,066
Unrealized (losses) gains on cash flow hedges, net of tax of $(5), $15 and $3	(8)	23	7
Total other comprehensive (loss) income, net of tax	(467)	(509)	1,214
Comprehensive income	885	801	2,402
Comprehensive income attributable to noncontrolling interests	21	72	31
Comprehensive income attributable to MEHC	$ 864	$ 729	$ 2,371

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

MidAmerican Energy Holdings Company ("MEHC") is a holding company that owns subsidiaries principally engaged in energy businesses (collectively with its subsidiaries, the "Company"). MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

The Company's operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, LLC ("MidAmerican Funding") (which primarily consists of MidAmerican Energy Company ("MidAmerican Energy")), Northern Natural Gas Company ("Northern Natural Gas"), Kern River Gas Transmission Company ("Kern River"), Northern Powergrid Holdings Company ("Northern Powergrid Holdings") (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), CalEnergy Philippines (which owns a majority interest in the Casecnan project in the Philippines), MidAmerican Renewables, LLC (formerly CalEnergy U.S., which owns interests in independent power projects in the United States), and HomeServices of America, Inc. (collectively with its subsidiaries, "HomeServices"). Through these platforms, the Company owns and operates an electric utility company in the Western United States, an electric and natural gas utility company in the Midwestern United States, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of independent power projects and the second largest residential real estate brokerage firm in the United States. Effective December 31, 2011, Northern Natural Gas and Kern River have been aggregated in the reportable segment called MidAmerican Energy Pipeline Group, and CalEnergy Philippines and MidAmerican Renewables, LLC have been aggregated in the reportable segment called MidAmerican Renewables.

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of MEHC and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. The Consolidated Statements of Operations include the revenue and expenses of any acquired entities from the date of acquisition. Intercompany accounts and transactions have been eliminated.

As of December 31, 2011, the Company changed its presentation of regulatory assets and liabilities, which previously had been classified entirely as noncurrent, to present such regulatory assets and liabilities as either current or noncurrent based on the timing of the collection or refund of the respective regulatory asset or liability. To conform to the presentation as of December 31, 2011, the Company reclassified on the Consolidated Balance Sheet as of December 31, 2010, $64 million from noncurrent regulatory assets to other current assets and $26 million from noncurrent regulatory liabilities to other current liabilities. Additionally, to conform to the presentation as of December 31, 2011, the Company reclassified on the Consolidated Balance Sheet as of December 31, 2010, equity method investments totaling $588 million from other assets to noncurrent investments and restricted cash and investments.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; goodwill; long-lived asset recovery; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp, MidAmerican Energy, Northern Natural Gas and Kern River (the "Domestic Regulated Businesses") prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Domestic Regulated Businesses are required to defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates.

The Company continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition which could limit the Domestic Regulated Businesses' ability to recover their costs. Based upon this continuous evaluation, the Company believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels and is subject to change in the future. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered in determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash Equivalents and Restricted Cash and Investments

Cash equivalents consist of funds invested in United States Treasury Bills, money market funds and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted amounts are included in investments and restricted cash and investments on the Consolidated Balance Sheets.

Investments

The Company's management determines the appropriate classification of investments in debt and equity securities at the acquisition date and reevaluates the classification at each balance sheet date. Investments and restricted cash and investments that management does not intend to use in current operations are presented as noncurrent on the Consolidated Balance Sheets.

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. Realized and unrealized gains and losses on securities in a trust related to the decommissioning of nuclear generation assets are recorded as net regulatory assets or liabilities since the Company expects to recover costs for these activities through regulated rates. Trading securities are carried at fair value with changes in fair value recognized in earnings. Held-to-maturity securities are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity.

If in management's judgment a decline in the fair value of an available-for-sale or held-to-maturity investment below cost is deemed other than temporary, the cost of the investment is written down to fair value. Factors considered in judging whether an impairment is other than temporary include: the financial condition, business prospects and creditworthiness of the issuer; the relative amount of the decline; the Company's ability and intent to hold the investment until the fair value recovers; and the length of time that fair value has been less than cost. Impairment losses on equity securities are charged to earnings. With respect to an investment in a debt security, any resulting impairment loss is recognized in earnings if the Company intends to sell or expects to be required to sell the debt security before amortized cost is recovered. If the Company does not expect to ultimately recover the amortized cost basis even if it does not intend to sell the security, the credit loss component is recognized in earnings and any difference between fair value and the amortized cost basis, net of the credit loss, is reflected in other comprehensive income (loss) ("OCI"). For regulated investments, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in regulated rates is probable.

The Company utilizes the equity method of accounting with respect to investments when it possesses the ability to exercise significant influence, but not control, over the operating and financial policies of the investee. The ability to exercise significant influence is presumed when an investor possesses more than 20% of the voting interests of the investee. This presumption may be overcome based on specific facts and circumstances that demonstrate that the ability to exercise significant influence is restricted. In applying the equity method, the Company records the investment at cost and subsequently increases or decreases the carrying value of the investment by the Company's proportionate share of the net earnings or losses and OCI of the investee. The Company records dividends or other equity distributions as reductions in the carrying value of the investment.

Allowance for Doubtful Accounts

Trade receivables are stated at the outstanding principal amount, net of estimated allowances for doubtful accounts. The allowance for doubtful accounts is based on the Company's assessment of the collectibility of amounts owed to the Company by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. As of December 31, 2011 and 2010, the allowance for doubtful accounts totaled $21 million and $27 million, respectively, and is included in trade receivables, net on the Consolidated Balance Sheets.

Derivatives

The Company employs a number of different derivative contracts, including forwards, futures, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities; interest rate risk; and foreign currency exchange rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets on the Consolidated Balance Sheets.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or cost of sales on the Consolidated Statements of Operations.

For the Company's derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. For the Company's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as regulatory assets and liabilities, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for sales contracts; cost of sales and operating expense for purchase contracts and electricity, natural gas and fuel swap contracts; and interest expense for interest rate derivatives.

For the Company's derivatives designated as hedging contracts, the Company formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. The Company formally documents hedging activity by transaction type and risk management strategy.

Changes in the estimated fair value of a derivative contract designated and qualified as a cash flow hedge, to the extent effective, are included on the Consolidated Statements of Changes in Equity as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. The Company discontinues hedge accounting prospectively when it has determined that a derivative contract no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative contract no longer qualifies as an effective hedge, future changes in the estimated fair value of the derivative contract are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI will be immediately recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies totaling $331 million and $306 million as of December 31, 2011 and 2010, respectively, and fuel, which includes coal stocks, stored gas and fuel oil, totaling $359 million and $279 million as of December 31, 2011 and 2010, respectively. The cost of materials and supplies, coal stocks and fuel oil is determined primarily using the average cost method. The cost of stored gas is determined using either the last-in-first-out ("LIFO") method or the lower of average cost or market. With respect to inventories carried at LIFO cost, the replacement cost would be $27 million and $38 million higher as of December 31, 2011 and 2010, respectively.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. The Company capitalizes all construction related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include capitalized interest, including debt allowance for funds used during construction ("AFUDC"), and equity AFUDC. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. Additionally, MidAmerican Energy has regulatory arrangements in Iowa in which the carrying cost of certain utility plant has been reduced for amounts associated with electric returns on equity exceeding threshold levels.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by the Company's various regulatory authorities. Depreciation studies are completed by the Domestic Regulated Businesses to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by some of the various regulatory authorities. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Consolidated Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when the Company retires or sells a component of domestic regulated property, plant and equipment, it charges the original cost and any net proceeds from the disposition to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

The Domestic Regulated Businesses capitalize debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance the construction of domestic regulated facilities, as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, the Company is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

The Company recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. The Company's AROs are primarily related to the decommissioning of nuclear power plants and obligations associated with its other generating facilities and offshore natural gas pipelines. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value. The impacts of regulation are considered when evaluating the carrying value of regulated assets. For all other assets, any resulting impairment loss is reflected on the Consolidated Statements of Operations.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in business acquisitions. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31. Evaluating goodwill for impairment involves a two-step process. The first step is to estimate the fair value of the reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, a second step is performed. Under the second step, the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the current estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied goodwill value is charged to earnings as an impairment loss. A significant amount of judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. In estimating future cash flows, the Company incorporates current market information, as well as historical factors. As such, the determination of fair value incorporates significant unobservable inputs. During 2011, 2010 and 2009, the Company did not record any goodwill impairment.

The Company records goodwill adjustments for (a) the tax benefit associated with the excess of tax-deductible goodwill over the reported amount of goodwill and (b) changes to the purchase price allocation prior to the end of the allocation period, which is not to exceed one year from the acquisition date.

Revenue Recognition

Energy Businesses

Revenue from energy business customers is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed, as well as unbilled, amounts. As of December 31, 2011 and 2010, unbilled revenue was $474 million and $452 million, respectively, and is included in trade receivables, net on the Consolidated Balance Sheets. Rates charged by energy businesses are established by regulators or contractual arrangements. When preliminary rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. The Company records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Real Estate Commission Revenue and Related Fees

Commission revenue from real estate brokerage transactions and related amounts due to agents are recognized when a real estate transaction is closed. Title and escrow closing fee revenue from real estate transactions and related amounts due to the title insurer are recognized at closing.

Unamortized Debt Premiums, Discounts and Financing Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Foreign Currency

The accounts of foreign-based subsidiaries are measured in most instances using the local currency of the subsidiary as the functional currency. Revenue and expenses of these businesses are translated into United States dollars at the average exchange rate for the period. Assets and liabilities are translated at the exchange rate as of the end of the reporting period. Gains or losses from translating the financial statements of foreign-based operations are included in equity as a component of AOCI. Gains or losses arising from transactions denominated in a currency other than the functional currency of the entity that is party to the transaction are included in earnings.

Income Taxes

Berkshire Hathaway includes the Company in its United States federal income tax return. Consistent with established regulatory practice, the Company's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are associated with income tax benefits related to certain property-related basis differences and other various differences that PacifiCorp and MidAmerican Energy (the "Utilities") are required to pass on to their customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability. These amounts were recognized as a net regulatory asset totaling $1.003 billion and $917 million as of December 31, 2011 and 2010, respectively, and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense in the period of enactment. Valuation allowances are established for certain deferred income tax assets where realization is not likely. Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions.

The Company has not established deferred income taxes on the undistributed foreign earnings of Northern Powergrid Holdings or the related currency translation adjustment that have been determined by management to be reinvested indefinitely. The cumulative earnings were approximately $2.0 billion as of December 31, 2011. The Company periodically evaluates its capital requirements. If circumstances change in the future and a portion of Northern Powergrid Holdings' undistributed earnings were repatriated, the dividends would be subject to taxation in the United States. However, any United States income tax liability would be offset, in part, by available United States income tax credits with respect to corporate income taxes previously paid principally in the United Kingdom. Because of the availability of foreign income tax credits, it is not practicable to determine the United States income tax liability that would be recognized if such cumulative earnings were not reinvested indefinitely. The Company has established deferred income taxes on all other undistributed foreign earnings.

In determining the Company's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the Company's various regulatory jurisdictions. The Company's income tax returns are subject to continuous examinations by federal, state, local and foreign income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The Company recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. Although the ultimate resolution of the Company's federal, state, local and foreign income tax examinations is uncertain, the Company believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material adverse impact on the Company's consolidated financial results. The Company's unrecognized tax benefits are primarily included in accrued property, income and other taxes and other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations.

New Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011-11, which amends FASB Accounting Standards Codification ("ASC") Topic 210, "Balance Sheet." The amendments in this guidance require an entity to provide quantitative disclosures about offsetting financial instruments and derivative instruments. Additionally, this guidance requires qualitative and quantitative disclosures about master netting agreements or similar agreements when the financial instruments and derivative instruments are not offset. This guidance is effective for fiscal years beginning on or after January 1, 2013, and for interim periods within those fiscal years. The Company is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Consolidated Financial Statements.

In September 2011, the FASB issued ASU No. 2011-09, which amends FASB ASC Subtopic 715-80, "Compensation-Retirement Benefits-Multiemployer Plans." The amendments in this guidance require additional disclosures regarding an entity's participation in multiemployer pension plans and other postretirement benefit plans, as well as certain qualitative and quantitative disclosures regarding individually significant multiemployer pension plans. This guidance is effective for annual reporting periods ending after December 15, 2011. The adoption of this guidance did not have a material impact on the Company's disclosures included within Notes to Consolidated Financial Statements.

In September 2011, the FASB issued ASU No. 2011-08, which amends FASB ASC Topic 350, "Intangibles-Goodwill and Other." The amendments in this guidance provide an entity the option to assess qualitatively whether it is necessary to perform the current two-step goodwill impairment test. An entity would be required to perform step one if it determines qualitatively that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount. Otherwise, no further testing would be required. This guidance is effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011, and is not expected to have an impact on the Company's Consolidated Financial Statements.

In June 2011, the FASB issued ASU No. 2011-05, which amends FASB ASC Topic 220, "Comprehensive Income." ASU No. 2011-05 provides an entity with the option to present the total of 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. Regardless of the option chosen, this guidance also requires presentation of items on the face of the financial statements that are reclassified from other comprehensive income to net income. This guidance does not change the items that must be reported in other comprehensive income, when an item of other comprehensive income must be reclassified to net income or how tax effects of each item of other comprehensive income are presented. This guidance is effective for interim and annual reporting periods beginning after December 15, 2011. The Company is currently evaluating which presentation option will be implemented. In December 2011, the FASB issued ASU No. 2011-12, which also amends FASB ASC Topic 220 to defer indefinitely the ASU No. 2011-05 requirement to present items on the face of the financial statements that are reclassified from other comprehensive income to net income. ASU No. 2011-12 is also effective for interim and annual reporting periods beginning after December 15, 2011.

In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC Topic 820, "Fair Value Measurements and Disclosures." The amendments in this guidance are not intended to result in a change in current accounting. ASU No. 2011-04 requires additional disclosures relating to fair value measurements categorized within Level 3 of the fair value hierarchy, including quantitative information about unobservable inputs, the valuation process used by the entity and the sensitivity of unobservable input measurements. Additionally, entities are required to disclose the level of the fair value hierarchy for assets and liabilities that are not measured at fair value in the balance sheet, but for which disclosure of the fair value is required. This guidance is effective for interim and annual reporting periods beginning after December 15, 2011. The Company is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Consolidated Financial Statements.

In January 2010, the FASB issued ASU No. 2010-06, which amends FASB ASC Topic 820, "Fair Value Measurements and Disclosures." ASU No. 2010-06 requires disclosure of (a) the amount of significant transfers into and out of Levels 1 and 2 of the fair value hierarchy and the reasons for those transfers and (b) gross presentation of purchases, sales, issuances and settlements in the Level 3 fair value measurement rollforward. This guidance clarifies that existing fair value measurement disclosures should be presented for each class of assets and liabilities. The existing disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements have also been clarified to ensure such disclosures are presented for the Levels 2 and 3 fair value measurements. The Company adopted this guidance as of January 1, 2010, with the exception of the disclosure requirement to present purchases, sales, issuances and settlements gross in the Level 3 fair value measurement rollforward, which the Company adopted as of January 1, 2011. The adoption of this guidance did not have a material impact on the Company's disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2011	2010
Regulated assets:			
Utility generation, distribution and transmission system	5-80 years	$ 40,180	$ 37,643
Interstate pipeline assets	3-80 years	6,245	5,906
		46,425	43,549
Accumulated depreciation and amortization		(14,390)	(13,711)
Regulated assets, net		32,035	29,838
Nonregulated assets:			
Independent power plants	5-30 years	677	678
Other assets	3-30 years	429	419
		1,106	1,097
Accumulated depreciation and amortization		(533)	(492)
Nonregulated assets, net		573	605
Net operating assets		32,608	30,443
Construction work-in-progress		1,559	1,456
Property, plant and equipment, net		$ 34,167	$ 31,899

Substantially all of the construction work-in-progress as of December 31, 2011 and 2010 relates to the construction of regulated assets.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements, the Domestic Regulated Businesses, as tenants in common, have undivided interests in jointly owned generation, transmission, distribution and pipeline common facilities. The Company accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include the Company's share of the expenses of these facilities.

The amounts shown in the table below represent the Company's share in each jointly owned facility as of December 31, 2011 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
PacifiCorp:				
Jim Bridger Nos. 1-4	67%	$ 1,074	$ 491	$ 21
Hunter No. 1	94	342	146	43
Hunter No. 2	60	291	80	12
Wyodak	80	449	152	1
Colstrip Nos. 3 and 4	10	222	116	2
Hermiston(1)	50	171	52	1
Craig Nos. 1 and 2	19	176	88	—
Hayden No. 1	25	51	24	—
Hayden No. 2	13	32	15	—
Foote Creek	79	37	18	—
Transmission and distribution facilities	Various	315	50	1
Total PacifiCorp		3,160	1,232	81
MidAmerican Energy:				
Louisa No. 1	88%	736	355	1
Walter Scott, Jr. No. 3	79	537	259	1
Walter Scott, Jr. No. 4(2)	60	442	55	—
Quad Cities Nos. 1 and 2(3)	25	573	264	36
Ottumwa No. 1	52	266	166	12
George Neal No. 4	41	170	142	11
George Neal No. 3	72	147	118	7
Transmission facilities	Various	236	71	—
Total MidAmerican Energy		3,107	1,430	68
MidAmerican Energy Pipeline Group - common facilities	Various	349	174	—
Total		$ 6,616	$ 2,836	$ 149

(1) PacifiCorp has contracted to purchase the remaining 50% of the output of the Hermiston generating facility.

(2) Facility in service and accumulated depreciation amounts are net of credits applied under Iowa revenue sharing arrangements totaling $306 million and $37 million, respectively.

(3) Includes amounts related to nuclear fuel.

(5) Regulatory Matters

Regulatory Assets and Liabilities

Regulatory assets represent costs that are expected to be recovered in future regulated rates. The Company's regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2011	2010
Noncurrent regulatory assets:			
Deferred income taxes[1]	30 years	$ 1,069	$ 978
Employee benefit plans[2]	10 years	834	612
Unrealized loss on regulated derivative contracts	3 years	421	566
Unamortized contract values[3]	9 years	187	—
Other	Various	324	277
Noncurrent regulatory assets		2,835	2,433
Current regulatory assets		83	64
Total regulatory assets		$ 2,918	$ 2,497

(1) Amounts primarily represent income tax benefits related to state accelerated tax depreciation and certain property-related basis differences that were previously flowed through to customers and will be included in regulated rates when the temporary differences reverse.

(2) Substantially represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized.

(3) Represents frozen values of contracts previously accounted for as derivatives and recorded at fair value, including $168 million reclassified from unrealized loss on regulated derivative contracts to unamortized contract values as a result of designating certain commodity derivatives as normal purchases or normal sales in December 2011. Refer to Note 7 for additional information.

The Company had regulatory assets not earning a return on investment of $2.602 billion and $2.263 billion as of December 31, 2011 and 2010, respectively.

Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. The Company's regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2011	2010
Noncurrent regulatory liabilities:			
Cost of removal[1]	30 years	$ 1,404	$ 1,376
Asset retirement obligations	28 years	88	129
Employee benefit plans[2]	19 years	12	23
Unrealized gain on regulated derivative contracts	1 year	21	2
Other	Various	138	108
Noncurrent regulatory liabilities		1,663	1,638
Current regulatory liabilities		68	26
Total regulatory liabilities		$ 1,731	$ 1,664

(1) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices. Amounts are deducted from rate base or otherwise accrue a carrying cost.

(2) Represents amounts not yet recognized as a component of net periodic benefit cost that are to be returned to customers in future periods when recognized.

(6) Fair Value Measurements

The carrying value of the Company's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. The Company has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect the Company's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Company develops these inputs based on the best information available, including its own data.

The following table presents the Company's assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other[1]	Total
As of December 31, 2011					
Assets:					
Commodity derivatives	$ 1	$ 166	$ 27	$ (147)	$ 47
Money market mutual funds[2]	164	—	—	—	164
Debt securities:					
United States government obligations	89	—	—	—	89
International government obligations	—	1	—	—	1
Corporate obligations	—	30	—	—	30
Municipal obligations	—	12	—	—	12
Agency, asset and mortgage-backed obligations	—	7	—	—	7
Auction rate securities	—	—	35	—	35
Equity securities:					
United States companies	166	—	—	—	166
International companies	489	—	—	—	489
Investment funds	64	—	—	—	64
	$ 973	$ 216	$ 62	$ (147)	$ 1,104
Liabilities - commodity derivatives	$ (37)	$ (598)	$ (4)	$ 303	$ (336)
As of December 31, 2010					
Assets:					
Commodity derivatives	$ 3	$ 293	$ 23	$ (175)	$ 144
Money market mutual funds[2]	301	—	—	—	301
Debt securities:					
United States government obligations	74	—	—	—	74
International government obligations	—	1	—	—	1
Corporate obligations	—	32	—	—	32
Municipal obligations	—	13	—	—	13
Agency, asset and mortgage-backed obligations	—	7	—	—	7
Auction rate securities	—	—	50	—	50
Equity securities:					
United States companies	166	—	—	—	166
International companies	1,183	—	—	—	1,183
Investment funds	63	—	—	—	63
	$ 1,790	$ 346	$ 73	$ (175)	$ 2,034
Liabilities - commodity derivatives	$ (10)	$ (568)	$ (354)	$ 316	$ (616)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $156 million and $141 million as of December 31, 2011 and 2010, respectively.

(2) Amounts are included in cash and cash equivalents; current investments and restricted cash and investments; and noncurrent investments and restricted cash and investments on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by the Company. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the applicable term of the Company's outstanding derivative contracts; therefore, the Company's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, the Company uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 7 for further discussion regarding the Company's risk management and hedging activities.

The Company's investments in money market mutual funds and debt and equity securities are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. The fair value of the Company's investments in auction rate securities, where there is no current liquid market, is determined using pricing models based on available observable market data and the Company's judgment about the assumptions, including liquidity and nonperformance risks, which market participants would use when pricing the asset.

The following table reconciles the beginning and ending balances of the Company's assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	Commodity Derivatives			Auction Rate Securities		
	2011	2010	2009	2011	2010	2009
Beginning balance	$ (331)	$ (359)	$ (369)	$ 50	$ 46	$ 37
Changes included in earnings[1]	23	14	22	—	—	—
Changes in fair value recognized in OCI	(3)	—	—	—	4	9
Changes in fair value recognized in net regulatory assets	144	(33)	12	—	—	—
Contracts designated as normal purchases or normal sales[2]	168	—	—	—	—	—
Sales	—	—	—	(15)	—	—
Settlements	21	44	(2)	—	—	—
Transfers to Level 2	—	3	(22)	—	—	—
Transfers from Level 2	1	—	—	—	—	—
Ending balance	$ 23	$ (331)	$ (359)	$ 35	$ 50	$ 46

(1) Changes included in earnings are reported as operating revenue on the Consolidated Statements of Operations. For commodity derivatives held as of December 2011, 2010 and 2009, net unrealized gains (losses) included in earnings for the years ended December 31, 2011, 2010 and 2009 totaled $15 million, $8 million and $15 million, respectively.

(2) In December 2011, PacifiCorp elected to designate certain derivative contracts as normal purchases or normal sales, an exception afforded by GAAP. As a result of making the designation, the fair value of the contacts was frozen as of December 31, 2011 and $168 million of net derivative liabilities were reclassified from derivative contracts to other assets and liabilities. The frozen liability and associated regulatory asset will be amortized over the remaining terms of the agreements.

The Company's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of the Company's long-term debt has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of the Company's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of the Company's long-term debt as of December 31 (in millions):

	2011		2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 19,072	$ 23,327	$ 19,491	$ 21,637

(7) Risk Management and Hedging Activities

The Company is exposed to the impact of market fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through MEHC's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. MidAmerican Energy also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for regulated and nonregulated retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. Additionally, the Company is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain. The Company does not engage in a material amount of proprietary trading activities.

Each of the Company's business platforms has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, the Company uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. The Company manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, the Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate the Company's exposure to interest rate risk. The Company does not hedge all of its commodity price, interest rate and foreign currency exchange rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in the Company's accounting policies related to derivatives. Refer to Notes 2, 5 and 6 for additional information on derivative contracts.

The following table, which reflects master netting arrangements and excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of the Company's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Derivative Assets		Derivative Liabilities		
	Current	Noncurrent	Current	Noncurrent	Total
As of December 31, 2011					
Not designated as hedging contracts[1]:					
Commodity assets	$ 93	$ 14	$ 73	$ 13	$ 193
Commodity liabilities	(47)	(5)	(324)	(216)	(592)
Total	46	9	(251)	(203)	(399)
Designated as hedging contracts:					
Commodity assets	—	—	1	—	1
Commodity liabilities	(6)	—	(24)	(17)	(47)
Total	(6)	—	(23)	(17)	(46)
Total derivatives	40	9	(274)	(220)	(445)
Cash collateral (payable) receivable	(2)	—	114	44	156
Total derivatives - net basis	$ 38	$ 9	$ (160)	$ (176)	$ (289)
As of December 31, 2010					
Not designated as hedging contracts[1]:					
Commodity assets	$ 204	$ 18	$ 47	$ 38	$ 307
Commodity liabilities	(64)	(6)	(269)	(533)	(872)
Total	140	12	(222)	(495)	(565)
Designated as hedging contracts:					
Commodity assets	1	2	8	1	12
Commodity liabilities	(1)	(1)	(50)	(8)	(60)
Total	—	1	(42)	(7)	(48)
Total derivatives	140	13	(264)	(502)	(613)
Cash collateral (payable) receivable	(9)	—	106	44	141
Total derivatives - net basis	$ 131	$ 13	$ (158)	$ (458)	$ (472)

(1) The Company's commodity derivatives not designated as hedging contracts are generally included in regulated rates, and as of December 31, 2011 and 2010, a net regulatory asset of $400 million and $564 million, respectively, was recorded related to the net derivative liability of $399 million and $565 million, respectively.

Not Designated as Hedging Contracts

The following table reconciles the beginning and ending balances of the Company's net regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2011	2010	2009
Beginning balance	$ 564	$ 353	$ 446
Changes in fair value recognized in net regulatory assets	95	115	(119)
Net losses reclassified from AOCI	—	49	—
Net losses reclassified to unamortized contract value regulatory asset	(168)	—	—
Net gains reclassified to operating revenue	12	80	293
Net losses reclassified to cost of sales	(103)	(33)	(267)
Ending balance	$ 400	$ 564	$ 353

Designated as Hedging Contracts

The Company uses derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices for delivery to nonregulated customers, spring operational sales, natural gas storage and other transactions.

The following table reconciles the beginning and ending balances of the Company's accumulated other comprehensive loss (pre-tax) and summarizes pre-tax gains and losses on derivative contracts designated and qualifying as cash flow hedges recognized in other comprehensive income ("OCI"), as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2011	2010	2009		
	Commodity Derivatives	Commodity Derivatives	Commodity Derivatives	Interest Rate Derivative	Total
Beginning balance[1]	$ 37	$ 81	$ 83	$ 6	$ 89
Changes in fair value recognized in OCI	25	35	99	—	99
Net losses reclassified to regulatory assets	—	(49)	—	—	—
Net gains reclassified to operating revenue	3	14	11	—	11
Net losses reclassified to cost of sales	(19)	(44)	(112)	—	(112)
Net losses reclassified to interest expense	—	—	—	(6)	(6)
Ending balance[1]	$ 46	$ 37	$ 81	$ —	$ 81

(1) Certain derivative contracts, principally interest rate locks, have settled and the fair value at the date of settlement remains in AOCI and is recognized in earnings when the forecasted transactions impact earnings.

Realized gains and losses on hedges and hedge ineffectiveness are recognized in income as operating revenue, cost of sales, operating expense or interest expense depending upon the nature of the item being hedged. For the years ended December 31, 2011, 2010 and 2009, hedge ineffectiveness was insignificant. As of December 31, 2011, the Company had cash flow hedges with expiration dates extending through December 2015 and $27 million of pre-tax net unrealized losses are forecasted to be reclassified from AOCI into earnings over the next twelve months as contracts settle.

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2011	2010
Electricity purchases (sales)	Megawatt hours	6	(11)
Natural gas purchases	Decatherms	183	239
Fuel purchases	Gallons	19	20

Credit Risk

The Utilities extend unsecured credit to other utilities, energy marketing companies, financial institutions and other market participants in conjunction with their wholesale energy supply and marketing activities. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with the counterparty.

The Utilities analyze the financial condition of each significant wholesale counterparty before entering into any transactions, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of wholesale counterparties, the Utilities enter into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed fees for delayed payments. If required, the Utilities exercise rights under these arrangements, including calling on the counterparty's credit support arrangement.

MidAmerican Energy also has potential indirect credit exposure to other market participants in the regional transmission organization ("RTO") markets where it actively participates, including the Midwest Independent Transmission System Operator, Inc. and the PJM Interconnection, L.L.C. In the event of a default by a RTO market participant on its market-related obligations, losses are allocated among all other market participants in proportion to each participant's share of overall market activity during the period of time the loss was incurred, diversifying MidAmerican Energy's exposure to credit losses from individual participants. Transactional activities of MidAmerican Energy and other participants in organized RTO markets are governed by credit policies specified in each respective RTO's governing tariff or related business practices. Credit policies of RTO's, which have been developed through extensive stakeholder participation, generally seek to minimize potential loss in the event of a market participant default without unnecessarily inhibiting access to the marketplace. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain provisions that require MEHC's subsidiaries, principally the Utilities, to maintain specific credit ratings from one or more of the major credit rating agencies on their unsecured debt. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in the subsidiary's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2011, these subsidiary's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of the Company's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $571 million and $603 million as of December 31, 2011 and 2010, respectively, for which the Company had posted collateral of $125 million and $136 million, respectively. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2011 and 2010, the Company would have been required to post $332 million and $261 million, respectively, of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

(8) Investments and Restricted Cash and Investments

Investments and restricted cash and investments consists of the following as of December 31 (in millions):

	2011	2010
Investments:		
BYD Company Limited common stock	$ 488	$ 1,182
Rabbi trusts	290	284
Other	99	105
Total investments	877	1,571
Equity method investments:		
CE Generation, LLC	255	254
Electric Transmission Texas, LLC	221	109
Bridger Coal Company	204	181
Other	52	44
Total equity method investments	732	588
Restricted cash and investments:		
Nuclear decommissioning trust funds	308	297
Debt service and other	82	57
Total restricted cash and investments	390	354
Total investments and restricted cash and investments	1,999	2,513
Less current portion	(51)	(44)
Noncurrent portion	$ 1,948	$ 2,469

Investments

MEHC's investment in BYD Company Limited common stock is accounted for as an available-for-sale security with changes in fair value recognized in AOCI. As of December 31, 2011 and 2010, the fair value of MEHC's investment in BYD Company Limited common stock was $488 million and $1.182 billion, respectively, which resulted in a pre-tax unrealized gain of $256 million and $950 million as of December 31, 2011 and 2010, respectively.

Rabbi trusts hold corporate-owned life insurance on certain current and former key executives and directors. The Rabbi trusts were established to hold investments used to fund the obligations of various nonqualified executive and director compensation plans and to pay the costs of the trusts. The amount represents the cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value.

Equity Method Investments

CE Generation, LLC is a company owned equally by subsidiaries of TransAlta Corporation and MEHC engaged in the independent power business, and through its subsidiaries, owns and operates ten geothermal generating facilities in the Imperial Valley of California and three natural gas-fueled combined cycle cogeneration facilities in New York, Texas and Arizona. Electric Transmission Texas, LLC is owned equally by subsidiaries of American Electric Power Company, Inc. and MEHC and owns and operates electric transmission assets in the Electric Reliability Council of Texas footprint. Bridger Coal Company ("Bridger Coal") is 66.67% owned by a subsidiary of MEHC and 33.33% owned by a subsidiary of Idaho Power Company and is a coal mining joint venture that supplies coal to the Jim Bridger generating facility. Bridger Coal is being accounted for under the equity method of accounting as the power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner.

Restricted Cash and Investments

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Nuclear Station Units 1 and 2 ("Quad Cities Station"). These investments in debt and equity securities are classified as available-for-sale and are reported at fair value. Funds are invested in the trust in accordance with applicable federal investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station, which are currently licensed for operation until December 2032. As of December 31, 2011 and 2010, 55% and 57%, respectively, of the fair value of the trust's funds was invested in domestic common equity securities, 10% and 11%, respectively, in domestic corporate debt securities and the remainder in investment grade municipal and United States government securities.

The Company has investments in interest bearing auction rate securities with par values of $58 million and $73 million as of December 31, 2011 and 2010, respectively, and remaining maturities of 5 to 25 years. The Company considers the securities to be temporarily impaired, except for an other-than-temporary impairment of $3 million, after tax, recorded in 2008, and has recorded unrealized losses on the securities of $12 million and $11 million, after tax, in AOCI as of December 31, 2011 and 2010, respectively. The Company does not intend to sell or expect to be required to sell the securities until the remaining principal investment is collected.

(9) Short-Term Debt and Revolving Credit Facilities

The following table summarizes MEHC's and its subsidiaries' availability under their revolving credit facilities as of December 31, (in millions):

	MEHC	PacifiCorp	MidAmerican Funding	Northern Powergrid Holdings	Home-Services	Total[1]
2011:						
Revolving credit facilities	$ 552	$ 1,355	$ 654	$ 233	$ 50	$ 2,844
Less:						
Short-term debt	(108)	(688)	—	(69)	—	(865)
Tax-exempt bond support and letters of credit	(25)	(304)	(195)	—	—	(524)
Net revolving credit facilities	$ 419	$ 363	$ 459	$ 164	$ 50	$ 1,455
2010:						
Revolving credit facilities	$ 585	$ 1,395	$ 654	$ 234	$ 50	$ 2,918
Less:						
Short-term debt	(284)	(36)	—	—	—	(320)
Tax-exempt bond support and letters of credit	(40)	(304)	(195)	—	—	(539)
Net revolving credit facilities	$ 261	$ 1,055	$ 459	$ 234	$ 50	$ 2,059

(1) The above table does not include unused revolving credit facilities and letters of credit for investments that are accounted for under the equity method.

As of December 31, 2011, the Company was in compliance with the covenants of its revolving credit facilities and letter of credit arrangements.

MEHC

MEHC has an unsecured credit facility with $552 million available until July 2012 and $479 million until July 2013. The credit facility has a variable interest rate based on the London Interbank Offered Rate ("LIBOR") plus a spread, which varies based on MEHC's credit ratings for its senior unsecured long-term debt securities, or a base rate, at MEHC's option. This facility is for general corporate purposes and also supports letters of credit for the benefit of certain subsidiaries and affiliates. As of December 31, 2011, MEHC had $108 million of borrowings outstanding under its credit facility at an average rate of 0.787% and had letters of credit issued under the credit agreement totaling $25 million. As of December 31, 2010, MEHC had $284 million of borrowings outstanding under its credit facility at an average rate of 0.508% and had letters of credit issued under the credit agreement totaling $40 million. The revolving credit agreement requires that MEHC's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.70 to 1.0 as of the last day of any quarter.

In January 2012, MEHC entered into a $500 million revolving loan agreement with a subsidiary of Berkshire Hathaway that is available until June 2012. The revolving loan facility has a variable interest rate based on LIBOR plus a spread.

PacifiCorp

PacifiCorp has a $635 million unsecured credit facility expiring in October 2012 and an unsecured credit facility with $720 million available until July 2012 and $630 million until July 2013. The credit facilities include a fixed or variable borrowing option for which rates vary based on the borrowing option and PacifiCorp's credit ratings for its senior unsecured long-term debt securities. These facilities support PacifiCorp's commercial paper program and certain variable-rate tax-exempt bond obligations. As of December 31, 2011, PacifiCorp had $688 million of commercial paper borrowings outstanding at a weighted-average interest rate of 0.5% and no borrowings outstanding under its credit facilities. As discussed in Note 12, in January 2012, PacifiCorp issued $650 million of long-term debt, the proceeds of which were in part used to repay a significant portion of the commercial paper borrowings outstanding as of December 31, 2011. As of December 31, 2010, PacifiCorp had $36 million of commercial paper borrowings outstanding at a weighted-average interest rate of 0.3% and no borrowings outstanding under its credit facilities.

As of December 31, 2011 and 2010, PacifiCorp had $601 million of letters of credit issued under committed arrangements, of which $304 million were issued under the revolving credit agreements. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations, were fully available as of December 31, 2011 and 2010, and expire periodically from May 2012 through November 2012.

Each revolving credit agreement and letter of credit arrangement requires that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization at no time exceed 0.65 to 1.0.

MidAmerican Funding

MidAmerican Energy has an unsecured credit facility with $645 million available until July 2012 and $530 million until July 2013, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations. The facility has a variable interest rate based on LIBOR plus a spread that varies based on MidAmerican Energy's credit ratings for its senior unsecured long-term debt securities, or a base rate, at MidAmerican Energy's option. In addition, MidAmerican Energy has a $5 million unsecured credit facility, which expires in June 2012 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2011 and 2010, MidAmerican Energy had no borrowings outstanding under its credit facilities, had no commercial paper borrowings outstanding and had $195 million of the $645 million revolving credit facility reserved to support the variable-rate tax-exempt bond obligations. The $645 million revolving credit agreement requires that MidAmerican Energy's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of any quarter.

MHC Inc., a direct wholly-owned subsidiary of MidAmerican Funding, has a $4 million unsecured credit facility, which expires in June 2012 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2011 and 2010, there were no borrowings outstanding under this credit facility.

Northern Powergrid Holdings

Northern Powergrid Holdings has a £150 million unsecured credit facility expiring in March 2013. The facility has a variable interest rate based on sterling LIBOR plus a spread that varies based on its credit ratings. As of December 31, 2011, Northern Powergrid Holdings had $69 million of borrowings outstanding under its credit facility at a weighted average interest rate of 2.14%. As of December 31, 2010, Northern Powergrid Holdings had no borrowings outstanding under its credit facility. The revolving credit agreement requires that Northern Powergrid Holdings' ratio of consolidated senior net debt, including current maturities, to regulated asset value not exceed 0.8 to 1.0 at Northern Powergrid Holdings and 0.65 to 1.0 at Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc as of June 30 and December 31. Additionally, Northern Powergrid Holdings' interest coverage ratio shall not be less than 2.5 to 1.0.

HomeServices

HomeServices has a $50 million unsecured credit facility expiring in December 2013. The facility has a variable interest rate based on the prime lending rate or LIBOR, at HomeServices' option, plus a spread that varies based on HomeServices' senior debt ratio. There were no borrowings outstanding as of December 31, 2011 and 2010. The revolving credit agreement requires that HomeServices maintain no borrowings under the facility for at least 45 consecutive days on a rolling twelve month basis and borrowings under the facility cannot exceed a ratio of senior debt to EBITDA of 2.0 to 1.0 at the end of any fiscal quarter.

(10) MEHC Senior Debt

MEHC senior debt represents unsecured senior obligations of MEHC and consists of the following, including fair value adjustments and unamortized premiums and discounts, as of December 31 (in millions):

	Par Value	2011	2010
3.15% Senior Notes, due 2012	$ 250	$ 250	$ 250
5.875% Senior Notes, due 2012	492	492	500
5.00% Senior Notes, due 2014	250	250	250
5.75% Senior Notes, due 2018	650	649	649
8.48% Senior Notes, due 2028	475	484	484
6.125% Senior Bonds, due 2036	1,700	1,699	1,699
5.95% Senior Bonds, due 2037	550	547	547
6.50% Senior Bonds, due 2037	1,000	992	992
Total MEHC Senior Debt	$ 5,367	$ 5,363	$ 5,371

(11) MEHC Subordinated Debt

MEHC subordinated debt consists of the following, including fair value adjustments, as of December 31 (in millions):

	Par Value	2011	2010
CalEnergy Capital Trust III-6.5%, due 2027	$ —	$ —	$ 150
MidAmerican Capital Trust II-11%, due 2012	22	22	65
MidAmerican Capital Trust III-11%, due 2011	—	—	100
Total MEHC Subordinated Debt	$ 22	$ 22	$ 315

In the fourth quarter of 2011, MEHC called and repaid at par value $191 million of 6.5% CalEnergy Capital Trust III subordinated debt due in September 2027 and recognized a loss on redemption of $40 million. In July 2010, MEHC called and repaid at par value $92 million of 6.25% CalEnergy Capital Trust II subordinated debt due in February 2012. In January 2009, MEHC repaid $500 million to affiliates of Berkshire Hathaway related to redeemable trust preferred securities issued by MidAmerican Capital Trust IV to affiliates of Berkshire Hathaway in September 2008. Interest expense to Berkshire Hathaway for the years ended December 31, 2011, 2010 and 2009 was $13 million, $30 million and $58 million, respectively.

(12) Subsidiary Debt

MEHC's direct and indirect subsidiaries are organized as legal entities separate and apart from MEHC and its other subsidiaries. Pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties, the long-term customer contracts of Kern River, the equity interest of MidAmerican Funding's subsidiary and substantially all of the assets of Cordova Energy Company LLC are pledged or encumbered to support or otherwise provide the security for their related subsidiary debt. It should not be assumed that the assets of any subsidiary will be available to satisfy MEHC's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets which are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MEHC or affiliates thereof. The long-term debt of subsidiaries may include provisions that allow MEHC's subsidiaries to redeem it in whole or in part at any time. These provisions generally include make-whole premiums.

Distributions at these separate legal entities are limited by various covenants including, among others, leverage ratios, interest coverage ratios and debt service coverage ratios. As of December 31, 2011, all subsidiaries were in compliance with their long-term debt covenants. However, Cordova Energy Company LLC is currently prohibited from making distributions by the terms of its indenture due to its failure to meet its debt service coverage ratio requirement.

Long-term debt of subsidiaries consists of the following, including fair value adjustments and unamortized premiums and discounts, as of December 31 (in millions):

	Par Value	2011	2010
PacifiCorp	$ 6,314	$ 6,300	$ 6,500
MidAmerican Funding	3,465	3,401	3,350
MidAmerican Energy Pipeline Group	1,665	1,665	1,790
Northern Powergrid Holdings	2,027	2,128	1,962
MidAmerican Renewables	195	193	203
Total subsidiary debt	$ 13,666	$ 13,687	$ 13,805

PacifiCorp

PacifiCorp's long-term debt consists of the following, including unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value	2011	2010
First mortgage bonds:			
5.0% to 8.8%, due through 2016	$ 457	$ 457	$ 1,043
3.9% to 8.5%, due 2017 to 2021	1,271	1,268	869
6.7% to 8.3%, due 2022 to 2026	404	404	404
7.7% due 2031	300	299	299
5.3% to 6.1%, due 2034 to 2036	850	848	848
5.8% to 6.4%, due 2037 to 2039	2,150	2,142	2,142
Tax-exempt bond obligations:			
Variable-rate series (2011-0.05% to 0.11%, 2010-0.28% to 0.41%):			
Due 2013(1)(2)	41	41	41
Due 2014 to 2025(2)	325	325	325
Due 2016 to 2024(1)(2)	221	221	221
Variable-rate series, due 2014 to 2025(1)(3)	68	68	68
5.6% to 5.7%, due 2021 to 2023(1)	71	71	71
6.2%, due 2030	13	13	13
Capital lease obligations - 8.8% to 15.7%, due through 2036	143	143	156
Total PacifiCorp	$ 6,314	$ 6,300	$ 6,500

(1) Secured by pledged first mortgage bonds registered to and held by the tax-exempt bond trustee generally with the same interest rates, maturity dates and redemption provisions as the tax-exempt bond obligations.

(2) Supported by $601 million of letters of credit issued under committed bank arrangements. These letters of credit were undrawn as of December 31, 2011 and expire periodically through November 2012.

(3) Interest rates are currently fixed at 3.9% to 4.1% and are scheduled to reset in 2013.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $22 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2011.

In January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 1, 2022 and $300 million of its 4.10% First Mortgage Bonds due February 1, 2042. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes.

MidAmerican Funding

MidAmerican Funding's long-term debt consists of the following, including fair value adjustments and unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value	2011	2010
MidAmerican Funding:			
6.75% Senior Notes, due 2011	$ —	$ —	$ 200
6.927% Senior Notes, due 2029	325	286	285
Total MidAmerican Funding	325	286	485
MidAmerican Energy:			
Tax-exempt bond obligations -			
Variable-rate series (2011-0.15%, 2010-0.43%), due 2016-2038	195	195	195
Notes:			
5.65% Series, due 2012	—	—	400
5.125% Series, due 2013	275	275	275
4.65% Series, due 2014	350	350	350
5.95% Series, due 2017	250	250	250
5.3% Series, due 2018	350	349	349
6.75% Series, due 2031	400	396	396
5.75% Series, due 2035	300	300	300
5.8% Series, due 2036	350	349	349
Turbine purchase obligation, 1.46%, due 2013	669	650	—
Other	1	1	1
Total MidAmerican Energy	3,140	3,115	2,865
Total MidAmerican Funding	$ 3,465	$ 3,401	$ 3,350

In conjunction with the construction of wind-powered generating facilities, MidAmerican Energy has accrued as construction work-in-progress amounts it is not contractually obligated to pay until December 2013. The amounts ultimately payable were discounted at 1.46% and recognized upon delivery of the equipment as long-term debt. The discount is being amortized as interest expense over the period until payment is due using the effective interest method. As of December 31, 2011, $650 million of such debt, net of associated discount, was outstanding.

In December 2011, MidAmerican Energy redeemed its 5.65% senior notes due July 2012 at a redemption price in accordance with the terms of the indenture.

MidAmerican Energy Pipeline Group

MidAmerican Energy Pipeline Group's long-term debt consists of the following, including unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value	2011	2010
Northern Natural Gas:			
7.0% Senior Notes, due 2011	$ —	$ —	$ 250
5.375% Senior Notes, due 2012	300	300	300
5.125% Senior Notes, due 2015	100	100	100
5.75% Senior Notes, due 2018	200	200	200
4.25% Senior Notes, due 2021	200	200	—
5.8% Senior Bonds, due 2037	150	150	150
Total Northern Natural Gas	950	950	1,000
Kern River:			
6.676% Senior Notes, due 2016	257	257	283
4.893% Senior Notes, due 2018	458	458	507
Total Kern River	715	715	790
Total MidAmerican Energy Pipeline Group	$ 1,665	$ 1,665	$ 1,790

Kern River's long-term debt amortizes monthly. Kern River provides a debt service reserve letter of credit in amounts that approximate the next six months of principal and interest payments due on the loans, which were equal to $62 million and $64 million as of December 31, 2011 and 2010, respectively.

Northern Powergrid Holdings

Northern Powergrid Holdings and its subsidiaries' long-term debt consists of the following, including fair value adjustments and unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value(1)	2011	2010
8.875% Bonds, due 2020	$ 155	$ 181	$ 184
9.25% Bonds, due 2020	311	355	361
3.901% to 4.586% European Investment Bank loans, due 2018 to 2022	418	418	236
7.25% Bonds, due 2022	311	334	337
7.25% Bonds, due 2028	288	301	303
5.125% Bonds, due 2035	311	307	308
5.125% Bonds, due 2035	233	232	233
Total Northern Powergrid Holdings	$ 2,027	$ 2,128	$ 1,962

(1) The par values for these debt instruments are denominated in sterling and have been converted to United States dollars at the applicable exchange rate.

MidAmerican Renewables

MidAmerican Renewables long-term debt consists of the following, including fair value adjustments, as of December 31 (dollars in millions):

	Par Value	2011	2010
Cordova Funding Corporation Bonds, 8.48% to 9.07%, due 2019[1]	$ 161	$ 159	$ 168
Other	34	34	35
Total MidAmerican Renewables	$ 195	$ 193	$ 203

[1] Amortizes semi-annually.

Annual Repayments of Long-Term Debt

The annual repayments of MEHC and subsidiary debt for the years beginning January 1, 2012 and thereafter, excluding fair value adjustments and unamortized premiums and discounts, are as follows (in millions):

	2012	**2013**	**2014**	**2015**	**2016**	**2017 and Thereafter**	**Total**
MEHC senior debt	$ 742	$ —	$ 250	$ —	$ —	$ 4,375	$ 5,367
MEHC subordinated debt	22	—	—	—	—	—	22
PacifiCorp	34	283	275	147	72	5,503	6,314
MidAmerican Funding	—	944	350	1	34	2,136	3,465
MidAmerican Energy Pipeline Group	388	80	81	185	190	741	1,665
Northern Powergrid Holdings	—	—	—	—	—	2,027	2,027
MidAmerican Renewables	12	14	16	15	19	119	195
Totals	$ 1,198	$ 1,321	$ 972	$ 348	$ 315	$ 14,901	$ 19,055

(13) Asset Retirement Obligations

The Company estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including plan revisions, inflation and changes in the amount and timing of the expected work.

The Company does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $1.404 billion and $1.376 billion as of December 31, 2011 and 2010, respectively.

As a result of the deconsolidation of Bridger Coal on January 1, 2010, the Company deconsolidated $79 million of ARO liabilities and mine reclamation trust funds. The following table reconciles the beginning and ending balances of the Company's ARO liabilities for the years ended December 31, (in millions):

	2011	2010
Beginning balance	$ 390	$ 463
Deconsolidation of Bridger Coal	—	(79)
Change in estimated costs	38	(1)
Additions	39	2
Retirements	(19)	(17)
Accretion	23	22
Foreign currency exchange rate changes	(1)	—
Ending balance	$ 470	$ 390
Reflected as:		
Other current liabilities	$ 20	$ 8
Other long-term liabilities	450	382
	$ 470	$ 390
Nuclear decommissioning trust funds	$ 308	$ 297

The Company's most significant ARO liabilities relate to the decommissioning of nuclear power plants and obligations associated with its other generating facilities and offshore natural gas pipelines. The Nuclear Regulatory Commission ("NRC") regulates the decommissioning of nuclear power plants, which includes the planning and funding for the decommissioning. In accordance with these regulations, MidAmerican Energy submits a biennial report to the NRC providing reasonable assurance that funds will be available to pay for its share of the Quad Cities Station decommissioning. The decommissioning costs are included in base rates in MidAmerican Energy's Iowa tariffs. MidAmerican Energy's share of estimated Quad Cities Station decommissioning costs was $230 million and $178 million as of December 31, 2011 and 2010, respectively. MidAmerican Energy has established trusts for the investment of decommissioning funds. The fair value of the assets held in the trusts was $306 million and $295 million as of December 31, 2011 and 2010, respectively, and is reflected in noncurrent investments and restricted cash and investments on the Consolidated Balance Sheets.

The change in estimated costs in 2011 is primarily the result of a new valuation study conducted by the operator of Quad Cities Station, consistent with its practice of periodically performing such studies. The revision decreased regulatory liabilities and did not impact net income. Additionally, Northern Natural Gas revised its offshore pipeline removal estimates based on a May 2011 letter order received from the Galveston District Corps of Engineers. The revision increased property, plant and equipment, net and did not impact net income.

Certain of the Company's decommissioning and reclamation obligations relate to jointly-owned facilities and mine sites, and as such, each subsidiary is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. The Company's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

(14) Employee Benefit Plans

Domestic Operations

Defined Benefit Plans

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees. PacifiCorp's pension plans include a noncontributory defined benefit pension plan and a supplemental executive retirement plan ("SERP"). MidAmerican Energy sponsors defined benefit pension plans covering a majority of all employees of MEHC and its domestic energy subsidiaries other than PacifiCorp. MidAmerican Energy's pension plans include a noncontributory defined benefit pension plan and a SERP. The Utilities also provide certain postretirement healthcare and life insurance benefits through various plans to eligible retirees.

Changes to the Company's domestic pension and other postretirement benefit plans include the following:

- Effective January 1, 2012, the Utilities changed the medical benefits for the majority of Medicare-eligible participants in the PacifiCorp-sponsored and MidAmerican Energy-sponsored other postretirement benefit plans. Medicare-eligible participants now enroll in individual medical plans, rather than company-sponsored plans, under which the Utilities contribute fixed amounts to the participant's health reimbursement account. As a result of this change, the Company's benefit obligations for its other postretirement benefit plans and its related regulatory assets decreased $72 million as of December 31, 2011.
- Non-union employees hired on or after January 1, 2008 are not eligible to participate in the PacifiCorp-sponsored or MidAmerican Energy-sponsored noncontributory defined benefit pension plans. These non-union employees are eligible to receive enhanced benefits under the PacifiCorp-sponsored and MidAmerican Energy-sponsored 401(k) plans.
- Certain union employees hired on or after specified dates in their union contracts are not eligible to participate in the PacifiCorp-sponsored or MidAmerican Energy-sponsored noncontributory defined benefit pension plans. During the past three years, several unions have elected to cease participation in the PacifiCorp-sponsored or MidAmerican Energy-sponsored noncontributory defined benefit pension plans. As a result of these elections, the benefits for these union employees have been frozen and they are eligible to receive enhanced benefits under the PacifiCorp-sponsored and MidAmerican Energy-sponsored 401(k) plans.

In March 2010, the President signed into law healthcare reform legislation that included provisions to reduce the tax deductibility of other postretirement costs by the amount of retiree drug subsidies received from the federal government beginning after December 31, 2012. As a result of this legislation, the Company increased deferred income tax liabilities and, consistent with the expectation that such additional income tax expense amounts are probable of inclusion in regulated rates, recorded a $53 million increase to net regulatory assets during the year ended December 31, 2010.

The law also contains a provision that requires a 40% excise tax for group health benefits that are provided to employees above certain premium thresholds beginning in 2018. The tax would apply to the amount of premiums in excess of the thresholds. Virtually all major areas of the healthcare reform legislation, including the 40% excise tax, are subject to interpretation and implementation rules that may take several years to complete. As of December 31, 2010, the Company's other postretirement benefit obligation increased by $12 million as a result of the projected impact of the excise tax on benefits provided to a certain bargaining unit.

Net Periodic Benefit Cost

For purposes of calculating the expected return on plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur.

Net periodic benefit cost for the plans included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2011	2010	2009	2011	2010	2009
Service cost	$ 28	$ 29	$ 35	$ 11	$ 10	$ 9
Interest cost	102	105	113	41	42	43
Expected return on plan assets	(118)	(114)	(113)	(43)	(43)	(41)
Net amortization	20	12	—	16	13	13
Net periodic benefit cost	$ 32	$ 32	$ 35	$ 25	$ 22	$ 24

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2011	2010	2011	2010
Plan assets at fair value, beginning of year	$ 1,506	$ 1,322	$ 605	$ 554
Employer contributions	126	141	30	26
Participant contributions	—	—	16	17
Actual return on plan assets	(13)	164	—	63
Benefits paid	(133)	(121)	(54)	(55)
Plan assets at fair value, end of year	$ 1,486	$ 1,506	$ 597	$ 605

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2011	2010	2011	2010
Benefit obligation, beginning of year	$ 1,974	$ 1,887	$ 770	$ 746
Service cost	28	29	11	10
Interest cost	102	105	41	42
Participant contributions	—	—	16	17
Plan amendments	(4)	—	(72)	(7)
Curtailment	—	(14)	—	—
Actuarial loss	123	88	58	14
Benefits paid, net of Medicare subsidy	(133)	(121)	(51)	(52)
Benefit obligation, end of year	$ 2,090	$ 1,974	$ 773	$ 770
Accumulated benefit obligation, end of year	$ 2,060	$ 1,937		

The funded status of the plans and the amounts recognized on the Consolidated Balance Sheets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2011	2010	2011	2010
Plan assets at fair value, end of year	$ 1,486	$ 1,506	$ 597	$ 605
Less - Benefit obligation, end of year	2,090	1,974	773	770
Funded status	$ (604)	$ (468)	$ (176)	$ (165)
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ —	$ —	$ 15	$ 27
Other current liabilities	(12)	(12)	—	—
Other long-term liabilities	(592)	(456)	(191)	(192)
Amounts recognized	$ (604)	$ (468)	$ (176)	$ (165)

The SERPs have no plan assets; however the Company has Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERPs. The cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $170 million and $165 million as of December 31, 2011 and 2010, respectively. These assets are not included in the plan assets in the above table, but are reflected in noncurrent investments and restricted cash and investments on the Consolidated Balance Sheets. The portion of the pension plans' projected benefit obligation related to the SERPs was $175 million and $165 million as of December 31, 2011 and 2010, respectively.

Unrecognized Amounts

The portion of the funded status of the plans not yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	Pension		Other Postretirement	
	2011	**2010**	**2011**	**2010**
Net loss	$ 734	$ 518	$ 254	$ 163
Prior service credit	(41)	(45)	(104)	(43)
Net transition obligation	—	—	—	19
Regulatory deferrals	(7)	(18)	3	4
Total	$ 686	$ 455	$ 153	$ 143

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2011 and 2010 is as follows (in millions):

	Regulatory Asset	**Regulatory Liability**	**Accumulated Other Comprehensive Loss**	**Total**
Pension				
Balance, December 31, 2009	$ 444	$ (9)	$ 7	$ 442
Net loss arising during the year	30	7	3	40
Curtailment	(14)	—	—	(14)
Net amortization	(13)	1	(1)	(13)
Total	3	8	2	13
Balance, December 31, 2010	447	(1)	9	455
Net loss arising during the year	246	1	8	255
Prior service credit arising during the year	(4)	—	—	(4)
Net amortization	(20)	—	—	(20)
Total	222	1	8	231
Balance, December 31, 2011	$ 669	$ —	$ 17	$ 686

	Regulatory Asset	Regulatory Liability	Deferred Income Taxes	Accumulated Other Comprehensive Loss	Total
Other Postretirement					
Balance, December 31, 2009	$ 152	$ (16)	$ 33	$ —	$ 169
Net loss (gain) arising during the year	5	(11)	—	—	(6)
Prior service credit arising during the year	—	(7)	—	—	(7)
Income tax benefits no longer realizable[1]	23	10	(33)	—	—
Net amortization	(15)	2	—	—	(13)
Total	13	(6)	(33)	—	(26)
Balance, December 31, 2010	165	(22)	—	—	143
Net loss arising during the year	86	12	—	1	99
Prior service credit arising during the year	(61)	(3)	—	(1)	(65)
Reduction in net transition obligation	(8)	—	—	—	(8)
Net amortization	(17)	1	—	—	(16)
Total	—	10	—	—	10
Balance, December 31, 2011	$ 165	$ (12)	$ —	$ —	$ 153

(1) Represents adjustments to regulatory assets associated with income tax benefits that will no longer be realized when the net periodic benefit cost is recognized as a result of the healthcare reform legislation.

The net loss, prior service credit and regulatory deferrals that will be amortized in 2012 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 47	$ (7)	$ (2)	$ 38
Other postretirement	13	(13)	1	1
Total	$ 60	$ (20)	$ (1)	$ 39

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			**Other Postretirement**		
	2011	**2010**	**2009**	**2011**	**2010**	**2009**
Benefit obligations as of December 31:						
PacifiCorp-sponsored plans						
Discount rate	4.90%	5.35%	5.80%	4.95%	5.45%	5.85%
Rate of compensation increase	3.50%	3.50%	3.00%	N/A	N/A	N/A
MidAmerican Energy-sponsored plans						
Discount rate	4.75%	5.50%	6.00%	4.75%	5.50%	6.00%
Rate of compensation increase	3.50%	3.50%	3.00%	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
PacifiCorp-sponsored plans						
Discount rate	5.35%	5.80%	6.90%	5.45%	5.85%	6.90%
Expected return on plan assets	7.50%	7.75%	7.75%	7.50%	7.75%	7.75%
Rate of compensation increase	3.50%	3.00%	3.50%	N/A	N/A	N/A
MidAmerican Energy-sponsored plans						
Discount rate	5.50%	6.00%	6.50%	5.50%	6.00%	6.50%
Expected return on plan assets	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
Rate of compensation increase	3.50%	3.00%	4.00%	N/A	N/A	N/A

	2011	**2010**
Assumed healthcare cost trend rates as of December 31:		
PacifiCorp-sponsored plans		
Healthcare cost trend rate assumed for next year	8.50%	8.00%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2016	2016
MidAmerican Energy-sponsored plans		
Healthcare cost trend rate assumed for next year	7.40%	8.00%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2016	2016

In establishing its assumption as to the expected return on plan assets, the Company utilizes the expected asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

A one percentage-point change in assumed healthcare cost trend rates would have the following effects (in millions):

	One Percentage-Point	
	Increase	**Decrease**
Increase (decrease) in:		
Total service and interest cost	$ 3	$ (2)
Other postretirement benefit obligation	48	(38)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $81 million and $9 million, respectively, during 2012. Funding to the established pension trusts is based upon the actuarially determined costs of the plans and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. The Company considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. The Company's funding policy for its other postretirement benefit plans is to contribute an amount equal to the sum of the net periodic benefit cost.

The expected benefit payments to participants in the Company's pension and other postretirement benefit plans for 2012 through 2016 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments			
		Other Postretirement		
	Pension	**Gross**	**Medicare Subsidy**	**Net of Subsidy**
2012	$ 151	$ 49	$ —	$ 49
2013	156	51	(1)	50
2014	160	52	(1)	51
2015	161	53	(1)	52
2016	167	55	(1)	54
2017-21	808	294	(9)	285

Plan Assets

Investment Policy and Asset Allocations

The Company's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment advisors to manage plan investments within the parameters outlined by each plan's Pension and Employee Benefits Plans Administrative Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments. The return on assets assumption for each plan is based on a weighted-average of the expected historical performance for the types of assets in which the plans invest.

The target allocations (percentage of plan assets) for the Company's pension and other postretirement benefit plan assets are as follows as of December 31, 2011:

	Pension(1)	**Other Postretirement**(1)
	%	%
PacifiCorp:		
Debt securities(2)	33-37	33-37
Equity securities(2)	53-57	61-65
Limited partnership interests	8-12	1-3
Other	0-1	0-1
MidAmerican Energy:		
Debt securities(2)	20-30	25-35
Equity securities(2)	65-75	60-80
Real estate funds	0-10	0
Other	0-5	0-5

(1) PacifiCorp's retirement plan trust includes a separate account that is used to fund benefits for the other postretirement plan. In addition to this separate account, the assets for the other postretirement benefit plans are held in two Voluntary Employees' Beneficiary Association ("VEBA") Trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plan include the separate account of the retirement plan trust and the two VEBA trusts.

(2) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds have been allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for the Company's defined benefit pension plans (in millions):

	Input Levels for Fair Value Measurements(1)			
	Level 1	**Level 2**	**Level 3**	**Total**
As of December 31, 2011				
Cash equivalents	$ —	$ 18	$ —	$ 18
Debt securities:				
United States government obligations	27	—	—	27
International government obligations	—	73	—	73
Corporate obligations	—	92	—	92
Municipal obligations	—	12	—	12
Agency, asset and mortgage-backed obligations	—	80	—	80
Equity securities:				
United States companies	481	—	—	481
International companies	7	—	—	7
Investment funds(2)	180	421	—	601
Limited partnership interests(3)	—	—	71	71
Real estate funds	—	—	24	24
Total	$ 695	$ 696	$ 95	$ 1,486
As of December 31, 2010				
Cash equivalents	$ —	$ 19	$ —	$ 19
Debt securities:				
United States government obligations	29	—	—	29
International government obligations	—	81	—	81
Corporate obligations	—	77	—	77
Municipal obligations	—	7	—	7
Agency, asset and mortgage-backed obligations	—	78	—	78
Equity securities:				
United States companies	489	—	—	489
International companies	7	—	—	7
Investment funds(2)	182	436	—	618
Limited partnership interests(3)	—	—	84	84
Real estate funds	—	—	17	17
Total	$ 707	$ 698	$ 101	$ 1,506

(1) Refer to Note 6 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 69% and 31%, respectively, for 2011 and 70% and 30%, respectively, for 2010. Additionally, these funds are invested in United States and international securities of approximately 66% and 34%, respectively, for 2011 and 62% and 38%, respectively, for 2010.

(3) Limited partnership interests include several funds that invest primarily in buyout, growth equity and venture capital.

The following table presents the fair value of plan assets, by major category, for the Company's defined benefit other postretirement plans (in millions):

	Input Levels for Fair Value Measurements(1)			
	Level 1	Level 2	Level 3	Total
As of December 31, 2011				
Cash equivalents	$ 9	$ —	$ —	$ 9
Debt securities:				
United States government obligations	8	—	—	8
International government obligations	—	5	—	5
Corporate obligations	—	12	—	12
Municipal obligations	—	31	—	31
Agency, asset and mortgage-backed obligations	—	15	—	15
Equity securities:				
United States companies	219	—	—	219
International companies	2	—	—	2
Investment funds(2)	196	94	—	290
Limited partnership interests(3)	—	—	6	6
Total	$ 434	$ 157	$ 6	$ 597
As of December 31, 2010				
Cash equivalents	$ 8	$ 1	$ —	$ 9
Debt securities:				
United States government obligations	5	—	—	5
International government obligations	—	7	—	7
Corporate obligations	—	16	—	16
Municipal obligations	—	28	—	28
Agency, asset and mortgage-backed obligations	—	12	—	12
Equity securities:				
United States companies	219	—	—	219
International companies	3	—	—	3
Investment funds(2)	192	107	—	299
Limited partnership interests(3)	—	—	7	7
Total	$ 427	$ 171	$ 7	$ 605

(1) Refer to Note 6 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 56% and 44%, respectively, for 2011 and 56% and 44%, respectively, for 2010. Additionally, these funds are invested in United States and international securities of approximately 67% and 33%, respectively, for both 2011 and 2010.

(3) Limited partnership interests include several funds that invest primarily in buyout, growth equity and venture capital.

When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. When observable market data is not available, the fair value is determined using unobservable inputs, such as estimated future cash flows, purchase multiples paid in other comparable third-party transactions or other information. Investments in limited partnerships are valued at estimated fair value based on the Plan's proportionate share of the partnerships' fair value as recorded in the partnerships' most recently available financial statements adjusted for recent activity and forecasted returns. The fair values recorded in the partnerships' financial statements are generally determined based on closing public market prices for publicly traded securities and as determined by the general partners for other investments based on factors including estimated future cash flows, purchase multiples paid in other comparable third-party transactions, comparable public company trading multiples and other information. The real estate funds determine fair value of their underlying assets using independent appraisals given there is no current liquid market for the underlying assets.

The following table reconciles the beginning and ending balances of the Company's plan assets measured at fair value using significant Level 3 inputs for the years ended December 31 (in millions):

	Pension		Other Postretirement-
	Limited Partnership Interests	Real Estate Funds	Limited Partnership Interests
Balance, December 31, 2008	$ 78	$ 27	$ 7
Actual return on plan assets still held at December 31, 2009	5	(9)	1
Purchases, sales, distributions and settlements	(3)	(3)	—
Balance, December 31, 2009	80	15	8
Actual return on plan assets still held at December 31, 2010	10	2	—
Purchases, sales, distributions and settlements	(6)	—	(1)
Balance, December 31, 2010	84	17	7
Actual return on plan assets still held at December 31, 2011	7	4	1
Purchases, sales, distributions and settlements	(20)	3	(2)
Balance, December 31, 2011	$ 71	$ 24	$ 6

Defined Contribution Plans

The Company sponsors defined contribution plans (401(k) plans) covering substantially all employees. The Company's contributions vary depending on the plan, but are based primarily on each participant's level of contribution and cannot exceed the maximum allowable for tax purposes. The Company's contributions to these plans were $60 million, $57 million and $56 million for the years ended December 31, 2011, 2010 and 2009, respectively. As previously described, certain participants now receive enhanced benefits in the 401(k) plans and no longer accrue benefits in the noncontributory defined benefit pension plans.

Foreign Operations

Defined Benefit Plan

Certain wholly-owned subsidiaries of Northern Powergrid Holdings participate in the Northern Electric group of the United Kingdom industry-wide Electricity Supply Pension Scheme (the "UK Plan"), which provides pension and other related defined benefits, based on final pensionable pay, to the majority of the employees of Northern Powergrid Holdings. The UK Plan is closed to employees hired after July 23, 1997. Employees hired after that date are covered by defined contribution plans sponsored by certain wholly-owned subsidiaries of Northern Powergrid Holdings.

Net Periodic Benefit Cost

For purposes of calculating the expected return on pension plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur.

Net periodic benefit cost for the UK Plan included the following components for the years ended December 31 (in millions):

	2011	2010	2009
Service cost	$ 19	$ 15	$ 13
Interest cost	92	89	84
Expected return on plan assets	(115)	(102)	(104)
Net amortization	37	30	13
Net periodic benefit cost	$ 33	$ 32	$ 6

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	2011	2010
Plan assets at fair value, beginning of year	$ 1,633	$ 1,523
Employer contributions	79	68
Participant contributions	4	5
Actual return on plan assets	141	156
Benefits paid	(85)	(68)
Foreign currency exchange rate changes	(13)	(51)
Plan assets at fair value, end of year	$ 1,759	$ 1,633

The following table is a reconciliation of the benefit obligation for the years ended December 31 (in millions):

	2011	2010
Benefit obligation, beginning of year	$ 1,655	$ 1,651
Service cost	19	15
Interest cost	92	89
Participant contributions	4	5
Actuarial loss	101	19
Benefits paid	(85)	(68)
Foreign currency exchange rate changes	(13)	(56)
Benefit obligation, end of year	$ 1,773	$ 1,655
Accumulated benefit obligation, end of year	$ 1,587	$ 1,557

The funded status of the UK Plan and the amounts recognized on the Consolidated Balance Sheets as of December 31 are as follows (in millions):

	2011	2010
Plan assets at fair value, end of year	$ 1,759	$ 1,633
Less - Benefit obligation, end of year	1,773	1,655
Funded status	$ (14)	$ (22)
Amounts recognized on the Consolidated Balance Sheets-other long-term liabilities	$ (14)	$ (22)

Unrecognized Amounts

The portion of the funded status of the UK Plan not yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	2011	2010
Net loss	$ 653	$ 619
Prior service cost	3	5
Total	$ 656	$ 624

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost, which are included in accumulated other comprehensive loss on the Consolidated Balance Sheets, for the years ended December 31 is as follows (in millions):

	2011	2010
Balance, beginning of year	$ 624	$ 709
Net loss (gain) arising during the year	74	(35)
Net amortization	(37)	(30)
Foreign currency exchange rate changes	(5)	(20)
Total	32	(85)
Balance, end of year	$ 656	$ 624

The net loss and prior service cost that will be amortized from accumulated other comprehensive loss in 2012 into net periodic benefit cost are estimated to be $54 million and $1 million, respectively.

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	2011	2010	2009
Benefit obligations as of December 31:			
Discount rate	4.80%	5.50%	5.70%
Rate of compensation increase	2.80%	3.20%	2.75%
Rate of future price inflation	2.80%	3.20%	3.20%
Net periodic benefit cost for the years ended December 31:			
Discount rate	5.50%	5.70%	6.40%
Expected return on plan assets	6.80%	6.60%	7.00%
Rate of compensation increase	3.20%	2.75%	3.25%
Rate of future price inflation	3.20%	3.20%	3.00%

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £50 million during 2012. The expected benefit payments to participants in the UK Plan for 2012 through 2016 and for the five years thereafter, using the foreign currency exchange rate as of December 31, 2011, are summarized below (in millions):

2012	$ 81
2013	83
2014	85
2015	87
2016	89
2017-2021	478

Plan Assets

Investment Policy and Asset Allocations

The investment policy for the UK Plan is to balance risk and return through a diversified portfolio of debt securities, equity securities and real estate. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The UK Plan retains outside investment advisors to manage plan investments within the parameters set by the trustees of the UK Plan in consultation with Northern Powergrid Holdings. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments. The return on assets assumption is based on a weighted-average of the expected historical performance for the types of assets in which the UK Plan invests.

The target allocations (percentage of plan assets) for the UK Plan assets are as follows as of December 31, 2011:

Debt securities(1)	55%
Equity securities(1)	35
Real estate funds	10

(1) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds have been allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of the UK Plan assets, by major category, (in millions):

	Input Levels for Fair Value Measurements(1)			
	Level 1	**Level 2**	**Level 3**	**Total**
As of December 31, 2011				
Cash equivalents	$ 9	$ —	$ —	$ 9
Debt securities:				
United Kingdom government obligations	360	—	—	360
Other international government obligations	—	26	—	26
Corporate obligations	—	139	—	139
Investment funds(2)	93	974	—	1,067
Real estate funds	—	—	158	158
Total	$ 462	$ 1,139	$ 158	$ 1,759
As of December 31, 2010				
Cash equivalents	$ 11	$ —	$ —	$ 11
Debt securities:				
United Kingdom government obligations	298	—	—	298
Other international government obligations	—	14	—	14
Corporate obligations	—	122	—	122
Investment funds(2)	90	950	—	1,040
Real estate funds	—	—	148	148
Total	$ 399	$ 1,086	$ 148	$ 1,633

(1) Refer to Note 6 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 45% and 55%, respectively, for 2011 and 52% and 48%, respectively, for 2010.

The fair value of the UK Plan's assets are determined similar to the plan assets of the domestic plans as discussed previously in the note.

The following table reconciles the beginning and ending balances of the UK Plan assets measured at fair value using significant Level 3 inputs for the years ended December 31 (in millions):

	Real Estate Funds		
	2011	2010	2009
Beginning balance	$ 148	$ 133	$ 116
Actual return on plan assets still held at period end	11	19	6
Foreign currency exchange rate changes	(1)	(4)	11
Ending balance	$ 158	$ 148	$ 133

(15) Income Taxes

Income tax expense consists of the following for the years ended December 31 (in millions):

	2011	2010	2009
Current:			
Federal	$ (820)	$ (822)	$ (648)
State	9	40	(36)
Foreign	168	126	102
	(643)	(656)	(582)
Deferred:			
Federal	1,012	940	842
State	(11)	(34)	13
Foreign	(59)	(46)	15
	942	860	870
Investment tax credits	(5)	(6)	(6)
Total	$ 294	$ 198	$ 282

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense is as follows for the years ended December 31:

	2011	2010	2009
Federal statutory income tax rate	35%	35%	35%
Federal and state income tax credits	(11)	(10)	(9)
State income tax, net of federal income tax benefit	2	3	2
Income tax method changes	(2)	(4)	(4)
Income tax effect of foreign income	(2)	(4)	(2)
Effects of ratemaking	(1)	(3)	(2)
Change in United Kingdom corporate income tax rate	(3)	(2)	—
Other, net	—	(1)	—
Effective income tax rate	18%	14%	20%

Federal and state income tax credits primarily relate to production tax credits at the Utilities. The Utilities' wind-powered generating facilities are eligible for federal renewable electricity production tax credits for 10 years from the date the facilities were placed in service.

In 2009 and 2010, MidAmerican Energy changed the method by which it determines current income tax deductions for administrative and general costs ("A&G Deduction") and the Utilities changed the method by which they determine current income tax deductions for repair costs ("Repairs Deduction") related to certain of their regulated utility assets. These changes result in current deductibility for those costs, which are capitalized for book purposes. The Utilities were allowed to retroactively apply the method changes and deduct amounts related to prior years' costs on the tax return that includes the year of change. State utility rate regulation in Iowa requires that the tax effect of certain temporary differences be flowed through immediately to customers. Therefore, amounts that would otherwise have been recognized in income tax expense have been included as changes in regulatory assets. This treatment of such temporary differences impacts income tax expense and effective tax rates from year to year.

Accordingly, MidAmerican Energy's A&G Deduction computed for tax years prior to 2010 resulted in the recognition of $44 million of net tax benefits in earnings for the year ended December 31, 2010. Additionally, earnings for the year ended December 31, 2010 reflect $17 million of net tax benefits recognized in connection with the Repairs Deduction for tax years prior to 2010 related to MidAmerican Energy's regulated natural gas utility assets and jointly owned regulated electric utility assets. The Repairs Deduction for prior tax years related to the majority of MidAmerican Energy's regulated electric utility assets resulted in the recognition of $55 million of net tax benefits in earnings for the year ended December 31, 2009. Additionally, regulatory assets increased $88 million and $95 million for the 2010 and 2009 method changes, respectively, in recognition of MidAmerican Energy's ability to recover increased tax expense when such temporary differences reverse.

In 2011, MidAmerican Energy recognized $35 million of net tax benefits in conjunction with the partial resolution of certain tax issues related to tax positions taken for these income tax method changes. The ongoing impact of these method changes, along with other items recognized currently in income tax expense as the result of ratemaking, is reflected in the effects of ratemaking line above.

In July 2011, the Company recognized $40 million of deferred income tax benefits upon the enactment of a reduction in the United Kingdom corporate income tax rate from 27% to 26% effective April 1, 2011, and a further reduction to 25% effective April 1, 2012. In July 2010, the Company recognized $25 million of deferred income tax benefits upon the enactment of the reduction in the United Kingdom corporate income tax rate from 28% to 27% effective April 1, 2011.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2011	2010
Deferred income tax assets:		
Regulatory liabilities	$ 716	$ 685
State and federal carryforwards	314	248
Employee benefits	311	269
AROs	179	153
Foreign carryforwards	152	293
Derivative contracts	175	226
Other	414	294
Total deferred income tax assets	2,261	2,168
Valuation allowances	(14)	(13)
Total deferred income tax assets, net	2,247	2,155
Deferred income tax liabilities:		
Property related items	(7,638)	(6,672)
Regulatory assets	(1,119)	(917)
Investments	(177)	(427)
Other	(254)	(377)
Total deferred income tax liabilities	(9,188)	(8,393)
Net deferred income tax liability	$ (6,941)	$ (6,238)
Reflected as:		
Current assets	$ 149	$ 103
Current liabilities	(14)	(43)
Non-current liabilities	(7,076)	(6,298)
	$ (6,941)	$ (6,238)

As of December 31, 2011, the Company has available state carryforwards, principally for net operating losses, totaling $277 million and federal carryforwards totaling $37 million, which expire at various intervals between 2012 and 2031. As of December 31, 2011, the Company has available $152 million of foreign carryforwards, principally foreign tax credit carryforwards that expire 10 years after the date the foreign earnings are repatriated through actual or deemed dividends and foreign net operating loss carryforwards that expire in 2028. As of December 31, 2011, the statute of limitation had not begun on the foreign tax credit carryforwards.

The United States Internal Revenue Service has closed examination of the Company's income tax returns through February 2006. In the United Kingdom, each legal entity is subject to examination by HM Revenue and Customs ("HMRC"), the United Kingdom equivalent of the United States Internal Revenue Service. HMRC has closed examination of the Company's income tax returns through 2008. In addition, state jurisdictions have closed examination of the Company's income tax returns through at least February 9, 2006, except for PacifiCorp where the examinations have been closed through 1993 in most cases. The Company's income tax returns in the Philippines, the most significant other foreign jurisdiction, have been closed through at least 2005.

A reconciliation of the beginning and ending balances of the Company's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2011	2010
Beginning balance	$ 308	$ 273
Additions based on tax positions related to the current year	15	3
Additions for tax positions of prior years	15	62
Reductions for tax positions of prior years	(58)	(19)
Statute of limitations	(12)	(14)
Settlements	—	(4)
Interest and penalties	(3)	7
Ending balance	$ 265	$ 308

As of December 31, 2011 and 2010, the Company had unrecognized tax benefits totaling $156 million and $189 million, respectively, that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect the Company's effective tax rate.

(16) Commitments and Contingencies

Commitments

The Company has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2011 are as follows (in millions):

	2012	2013	2014	2015	2016	2017 and Thereafter	Total
Contract type:							
Coal, electricity and natural gas contract commitments	$ 1,389	$ 1,061	$ 897	$ 712	$ 549	$ 3,621	$ 8,229
Construction commitments	757	380	86	434	8	52	1,717
Operating leases and easements	89	75	52	42	29	366	653
Maintenance, service and other contracts	73	50	45	29	22	142	361
	$ 2,308	$ 1,566	$ 1,080	$ 1,217	$ 608	$ 4,181	$ 10,960

Coal, Electricity and Natural Gas Contract Commitments

The Utilities have fuel supply and related transportation and lime contracts for their coal-fueled and natural gas generating facilities. The Utilities expect to supplement these contracts with additional contracts and spot market purchases to fulfill their future fossil fuel needs. The Utilities acquire a portion of their electricity through long-term purchases and exchange agreements. The Utilities have several power purchase agreements with wind-powered and other generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments. Included in the purchased electricity payments are any power purchase agreements that meet the definition of an operating lease.

Construction Commitments

The Company's firm construction commitments reflected in the table above include the following major construction projects:

- As part of the March 2006 acquisition of PacifiCorp, MEHC and PacifiCorp made a commitment to the state regulatory commissions in all six states in which PacifiCorp has retail customers to invest in certain transmission and distribution system projects that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization. As of December 31, 2011, PacifiCorp had two remaining capital projects to complete associated with this commitment: (a) the 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley that is expected to be placed in service in 2013 and (b) another segment of the Energy Gateway Transmission Expansion Program that is expected to be placed in service prior to 2021, depending on siting, permitting and construction schedules.
- PacifiCorp is constructing the 637-megawatt Lake Side 2 combined-cycle combustion turbine natural gas-fueled generating facility ("Lake Side 2"), which is expected to be placed in service in 2014.
- MidAmerican Energy is constructing 407 megawatts ("MW") of wind-powered generation that it expects to place in service in 2012.
- MidAmerican Energy has contracts for the construction of emissions control equipment at two of its jointly owned generating facilities to address air quality requirements. MidAmerican Energy's share of the resulting firm commitments is reflected in the table above.

Operating Leases and Easements

The Company has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, land and rail cars. These leases generally require the Company to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. The Company also has non-cancelable easements for land on which its wind-powered generating facilities are located. Rent expense on non-cancelable operating leases totaled $101 million for 2011, $88 million for 2010 and $88 million for 2009.

Maintenance, Service and Other Contracts

The Company has various non-cancelable maintenance, service and other contracts primarily related to turbine and equipment maintenance and various other service agreements.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company's current and future operations. The Company believes it is in material compliance with all applicable laws and regulations.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 44 generating facilities with an aggregate facility net owned capacity of 1,145 MW. The FERC regulates 98% of the net capacity of this portfolio through 15 individual licenses, which have terms of 30 to 50 years. PacifiCorp expects to incur ongoing operating and maintenance expense and capital expenditures associated with the terms of its renewed hydroelectric licenses and settlement agreements, including natural resource enhancements. PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses. Substantially all of PacifiCorp's remaining hydroelectric generating facilities are operating under licenses that expire between 2030 and 2058.

In February 2010, PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the State of California, the State of Oregon and various other governmental and non-governmental settlement parties signed the Klamath Hydroelectric Settlement Agreement ("KHSA"). Among other things, the KHSA provides that the United States Department of the Interior conduct scientific and engineering studies to assess whether removal of the Klamath hydroelectric system's four mainstem dams is in the public interest and will advance restoration of the Klamath Basin's salmonid fisheries. If it is determined that dam removal should proceed, dam removal is expected to commence no earlier than 2020.

Under the KHSA, PacifiCorp and its customers are protected from uncapped dam removal costs and liabilities. For dam removal to occur, federal legislation consistent with the KHSA must be enacted to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. If Congress does not enact legislation, then PacifiCorp will resume relicensing at the FERC. In November 2011, bills were introduced in both chambers of the United States Congress that, if passed, would enact the KHSA and a companion agreement that seeks to resolve other water-related conflicts and restore habitat in the Klamath basin. PacifiCorp expects that congressional hearings on the legislation may begin in early 2012.

In addition, the KHSA limits PacifiCorp's contribution to dam removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. An additional $250 million for dam removal costs is expected to be raised through a California bond measure or other appropriate State of California financing mechanism. If dam removal costs exceed $200 million and if the State of California is unable to raise the additional funds necessary for dam removal costs, sufficient funds would need to be provided by an entity other than PacifiCorp in order for the KHSA and dam removal to proceed.

PacifiCorp has begun collection of surcharges from Oregon customers for their share of dam removal costs, as approved by the Oregon Public Utility Commission ("OPUC"), and is depositing the proceeds in a trust account maintained by the OPUC. PacifiCorp will begin collection of surcharges from California customers for their share of dam removal costs, as approved by the California Public Utilities Commission ("CPUC"), upon the establishment of two trust accounts. In January 2012, the CPUC notified PacifiCorp that the necessary trust accounts had been established to allow PacifiCorp to begin collecting the dam removal surcharge from California customers. PacifiCorp is authorized to collect the surcharge over the next nine years.

As of December 31, 2011, PacifiCorp's property, plant and equipment, net included $124 million of costs associated with the Klamath hydroelectric system's four mainstem dams and the associated relicensing and settlement costs. PacifiCorp has received approvals from the OPUC, the CPUC and the Wyoming Public Service Commission to depreciate the Klamath hydroelectric system's four mainstem dams and the associated relicensing and settlement costs through the expected dam removal date. The depreciation rate changes were effective January 1, 2011 and will allow for full depreciation of the assets by December 2019 for those jurisdictions. PacifiCorp filed for consistent ratemaking treatment in the last Idaho general rate case, which was settled in January 2012. PacifiCorp expects to seek similar approval in Washington. As part of the July 2011 Utah general rate case settlement that was approved by the Utah Public Service Commission in August 2011, PacifiCorp and the other parties to the settlement agreed to defer a decision regarding the acceleration of the depreciation rates for the Klamath hydroelectric system's four mainstem dams to a future rate proceeding, at which time Utah's $34 million share of associated relicensing and settlement costs would be addressed.

Legal Matters

The Company is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

Guarantees

The Company has entered into guarantees as part of the normal course of business and the sale of certain assets. These guarantees are not expected to have a material impact on the Company's consolidated financial results.

(17) MEHC Shareholders' Equity

Common Stock

On March 14, 2000, and as amended on December 7, 2005, MEHC's shareholders entered into a Shareholder Agreement that provides specific rights to certain shareholders. One of these rights allows certain shareholders the ability to put their common shares back to MEHC at the then current fair value dependent on certain circumstances controlled by MEHC.

In March 2010, MEHC purchased 250,000 shares of common stock for $225 per share, or $56 million, from Mr. Scott (along with family members and related entities).

Common Stock Options

During 2009, 703,329 common stock options were exercised having an exercise price of $35.05 per share, or $25 million. Also in 2009, MEHC purchased the shares issued from the options exercised for $148 million. As a result, the Company recognized $125 million of stock-based compensation expense, including the Company's share of payroll taxes, for the year ended December 31, 2009, which is included in operating expense on the Consolidated Statements of Operations. As of December 31, 2009, there are no common stock options outstanding.

Restricted Net Assets

In connection with the 2006 acquisition of PacifiCorp by MEHC, MEHC and PacifiCorp have made commitments to the state commissions that limit the dividends PacifiCorp can pay to either MEHC or MEHC's wholly owned subsidiary, PPW Holdings LLC. As of December 31, 2011, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 44% of its total capitalization, excluding short-term debt and current maturities of long-term debt. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by MEHC as common equity. As of December 31, 2011, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or MEHC, if PacifiCorp's unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of December 31, 2011, PacifiCorp's unsecured debt rating was A- by Standard & Poor's Rating Services, BBB+ by Fitch Ratings and Baa1 by Moody's Investor Service.

In conjunction with the March 1999 acquisition of MidAmerican Energy by MEHC, MidAmerican Energy committed to the IUB to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain its common equity level above 42% of total capitalization unless circumstances beyond its control result in the common equity level decreasing to below 39% of total capitalization. MidAmerican Energy must seek the approval from the IUB of a reasonable utility capital structure if MidAmerican Energy's common equity level decreases below 42% of total capitalization, unless the decrease is beyond the control of MidAmerican Energy. MidAmerican Energy is also required to seek the approval of the IUB if MidAmerican Energy's common equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy. As of December 31, 2011, MidAmerican Energy's common equity ratio exceeded the minimum threshold computed on a basis consistent with its commitment.

As a result of these regulatory commitments, MEHC had restricted net assets of $7.346 billion as of December 31, 2011.

(18) Preferred Securities of Subsidiaries

The total outstanding preferred stock of PacifiCorp, which does not have mandatory redemption requirements, is $41 million as of December 31, 2011 and 2010, is included in noncontrolling interests on the Consolidated Balance Sheets and accrues annual dividends at varying rates between 4.52% to 7.0%. Generally, this preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. In the event of voluntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all preferred stock is entitled to stated value plus accrued dividends. Dividends on all preferred stock are cumulative. Holders also have the right to elect members to the PacifiCorp Board of Directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

The total outstanding cumulative preferred securities of MidAmerican Energy are not subject to mandatory redemption requirements, may be redeemed at the option of MidAmerican Energy at prices which, in the aggregate, totaled $28 million as of December 31, 2011 and 2010, and is included in noncontrolling interests on the Consolidated Balance Sheets. The securities accrue annual dividends at varying rates between 3.30% to 4.80%. The aggregate total the holders of all preferred securities outstanding as of December 31, 2011 and 2010 were entitled to upon involuntary bankruptcy was $27 million plus accrued dividends.

The total outstanding 8.061% cumulative preferred securities of a subsidiary of Northern Powergrid Holdings, which are redeemable in the event of the revocation of the subsidiary's electricity distribution license by the Secretary of State, was $56 million as of December 31, 2011 and 2010 and is included in noncontrolling interests on the Consolidated Balance Sheets.

(19) Components of Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss attributable to MEHC, net consists of the following components as of December 31 (in millions):

	2011	2010
Unrecognized amounts on retirement benefits, net of tax of $(182) and $(172)	$ (491)	$ (461)
Foreign currency translation adjustment	(307)	(297)
Unrealized gains on available-for-sale securities, net of tax of $96 and $375	142	561
Unrealized gains on cash flow hedges, net of tax of $10 and $15	15	23
Total accumulated other comprehensive loss attributable to MEHC, net	$ (641)	$ (174)

(20) Other, Net

Other, net, as shown on the Consolidated Statements of Operations, for the years ending December 31 consists of the following (in millions):

	2011	2010	2009
Allowance for equity funds used during construction	$ 72	$ 89	$ 68
Loss on redemption of MEHC subordinated debt	(40)	—	—
Corporate-owned life insurance income	9	17	24
Gain on Constellation Energy Group, Inc. investment	—	—	37
Other	10	4	17
Total other, net	$ 51	$ 110	$ 146

(21) Supplemental Cash Flows Information

The summary of supplemental cash flows information for the years ending December 31 is as follows (in millions):

	2011	2010	2009
Interest paid, net of amounts capitalized	$ 1,136	$ 1,128	$ 1,179
Income taxes received, net[1]	$ 575	$ 305	$ 288
Supplemental disclosure of non-cash investing transactions:			
Accounts payable related to property, plant and equipment additions	$ 406	$ 305	$ 341
Deferred payments on equipment purchased for wind-powered generation at MidAmerican Energy[2]	$ 647	$ —	$ —
Issuance of note payable to acquire noncontrolling interest	$ —	$ 35	$ —

(1) Includes $734 million, $433 million and $360 million of income taxes received from Berkshire Hathaway in 2011, 2010 and 2009, respectively.

(2) In conjunction with the construction of wind-powered generating facilities, MidAmerican Energy has accrued as property, plant and equipment, net certain amounts for which it is not contractually obligated to pay until December 2013. Refer to Note 12 for additional information.

(22) Segment Information

MEHC's reportable segments were determined based on how the Company's strategic units are managed. Effective December 31, 2011, the Company changed its reportable segments. Northern Natural Gas and Kern River have been aggregated in the reportable segment called MidAmerican Energy Pipeline Group, and CalEnergy Philippines and MidAmerican Renewables, LLC (formerly CalEnergy U.S.) have been aggregated in the reportable segment called MidAmerican Renewables. Prior year amounts have been changed to conform to the current presentation. The Company's reportable segments with foreign operations include Northern Powergrid Holdings, whose business is principally in Great Britain, and MidAmerican Renewables, whose business includes operations in the Philippines. Intersegment eliminations and adjustments, including the allocation of goodwill, have been made. Income tax expense reflects the impact of tax method changes discussed in Note 15. Information related to the Company's reportable segments is shown below (in millions):

	Years Ended December 31,		
	2011	2010	2009
Operating revenue:			
PacifiCorp	$ 4,586	$ 4,432	$ 4,457
MidAmerican Funding	3,503	3,815	3,699
MidAmerican Energy Pipeline Group	977	981	1,061
Northern Powergrid Holdings	1,014	802	825
MidAmerican Renewables	161	137	178
HomeServices	992	1,020	1,037
MEHC and Other[1]	(60)	(60)	(53)
Total operating revenue	$ 11,173	$ 11,127	$ 11,204
Depreciation and amortization:			
PacifiCorp	$ 623	$ 572	$ 558
MidAmerican Funding	337	345	336
MidAmerican Energy Pipeline Group	184	173	164
Northern Powergrid Holdings	169	157	165
MidAmerican Renewables	30	31	31
HomeServices	12	14	18
MEHC and Other[1]	(14)	(16)	(16)
Total depreciation and amortization	$ 1,341	$ 1,276	$ 1,256
Operating income:			
PacifiCorp	$ 1,099	$ 1,055	$ 1,079
MidAmerican Funding	428	460	469
MidAmerican Energy Pipeline Group	468	472	558
Northern Powergrid Holdings	615	474	394
MidAmerican Renewables	106	88	128
HomeServices	24	17	11
MEHC and Other[1]	(56)	(64)	(174)
Total operating income	2,684	2,502	2,465
Interest expense	(1,196)	(1,225)	(1,275)
Capitalized interest	40	54	41
Interest and dividend income	14	24	38
Other, net	51	110	146
Total income before income tax expense and equity income	$ 1,593	$ 1,465	$ 1,415

	Years Ended December 31,		
	2011	2010	2009
Interest expense:			
PacifiCorp	$ 406	$ 403	$ 412
MidAmerican Funding	183	192	197
MidAmerican Energy Pipeline Group	101	111	116
Northern Powergrid Holdings	151	146	153
MidAmerican Renewables	18	20	20
MEHC and Other(1)	337	353	377
Total interest expense	$ 1,196	$ 1,225	$ 1,275
Income tax expense:			
PacifiCorp	$ 215	$ 212	$ 236
MidAmerican Funding	(26)	(62)	(43)
MidAmerican Energy Pipeline Group	152	152	181
Northern Powergrid Holdings	76	51	66
MidAmerican Renewables	36	35	49
HomeServices	16	13	17
MEHC and Other(1)	(175)	(203)	(224)
Total income tax expense	$ 294	$ 198	$ 282
Capital expenditures:			
PacifiCorp	$ 1,506	$ 1,607	$ 2,328
MidAmerican Funding	566	338	439
MidAmerican Energy Pipeline Group	289	293	250
Northern Powergrid Holdings	309	349	387
MidAmerican Renewables	4	1	1
HomeServices	7	5	6
MEHC and Other	3	—	2
Total capital expenditures	$ 2,684	$ 2,593	$ 3,413

	As of December 31,	
	2011	2010
Property, plant and equipment, net:		
PacifiCorp	$ 17,460	$ 16,491
MidAmerican Funding	7,935	6,960
MidAmerican Energy Pipeline Group	4,126	3,957
Northern Powergrid Holdings	4,332	4,164
MidAmerican Renewables	413	439
HomeServices	47	51
MEHC and Other	(146)	(163)
Total property, plant and equipment, net	$ 34,167	$ 31,899
Total assets:		
PacifiCorp	$ 22,364	$ 21,410
MidAmerican Funding	12,430	11,134
MidAmerican Energy Pipeline Group	4,854	4,744
Northern Powergrid Holdings	5,690	5,512
MidAmerican Renewables	890	905
HomeServices	649	649
MEHC and Other	841	1,314
Total assets	$ 47,718	$ 45,668

(1) The remaining differences between the segment amounts and the consolidated amounts described as "MEHC and Other" relate principally to intersegment eliminations for operating revenue and, for the other items presented, to (a) corporate functions, including administrative costs, interest expense, corporate cash and investments and related interest income and (b) intersegment eliminations.

The following table shows the change in the carrying amount of goodwill by reportable segment for the years ended December 31, 2011 and 2010 (in millions):

	PacifiCorp	MidAmerican Funding	MidAmerican Energy Pipeline Group	Northern Powergrid Holdings	MidAmerican Renewables	Home-Services	Total
Balance, December 31, 2009	$ 1,126	$ 2,102	$ 257	$ 1,130	$ 71	$ 392	$ 5,078
Foreign currency translation	—	—	—	(29)	—	—	(29)
Other	—	—	(26)	—	—	2	(24)
Balance, December 31, 2010	1,126	2,102	231	1,101	71	394	5,025
Foreign currency translation	—	—	—	(4)	—	—	(4)
Other	—	—	(26)	—	—	1	(25)
Balance, December 31, 2011	$ 1,126	$ 2,102	$ 205	$ 1,097	$ 71	$ 395	$ 4,996

(23) Subsequent Events — Acquisitions

In January 2012, MEHC, through a wholly-owned subsidiary, acquired Topaz Solar Farms LLC ("Topaz") and its 550-MW solar project (the "Topaz Project") in California from a subsidiary of First Solar, Inc. ("First Solar"). The Topaz Project is expected to cost approximately $2.44 billion, including all interest during construction, and will be completed in 22 blocks with an aggregate tested capacity of 586 MW. The Topaz Project expects to place 45 MW in service in 2012, 236 MW in service in 2013, 252 MW in service in 2014 and 53 MW in service in 2015. The Topaz Project is being constructed pursuant to a fixed price, date certain, turn-key engineering, procurement and construction contract with a subsidiary of First Solar. Topaz will sell all the electricity, renewable energy credits and other environmental attributes produced by the project to Pacific Gas and Electric Company ("PG&E") pursuant to a 25 year power purchase agreement. A subsidiary of First Solar will operate and maintain the project under a 25 year, fixed-fee operating and maintenance agreement.

MEHC has committed to provide Topaz with equity to fund the costs of the Topaz Project in an amount up to $2.44 billion less, among other things, the gross proceeds of long-term debt issuances, project revenue prior to completion and the total equity contributions made by MEHC or its subsidiaries. If MEHC does not maintain a minimum credit rating from two of the following three ratings agencies of at least BBB- from Standard & Poor's Ratings Services or Fitch Ratings or Baa3 from Moody's Investors Service, MEHC's obligations under the equity commitment agreement would be supported by cash collateral or a letter of credit issued by a financial institution that meets certain minimum criteria specified in the financing documents. Upon reaching the final commercial operation date of the Topaz Project, MEHC will have no further obligation to make any equity contribution and any unused equity contribution obligations will be canceled.

In February 2012, Topaz issued $850 million of the 5.75% Series A Senior Secured Notes. The principal of the notes amortize beginning September 2015 with a final maturity in September 2039. The net proceeds will be used to fund or reimburse the costs and expenses related to the development, construction and financing of the Topaz Project, including amounts that have been advanced by, or will be advanced by, MEHC for the Topaz Project. Any unused amounts will be invested or, in certain circumstances, loaned to MEHC.

In connection with the offering, Topaz entered into a letter of credit and reimbursement facility in an aggregate principal amount of $345 million. Letters of credit issued under the letter of credit facility will be used to (a) provide security under the power purchase agreement and large generator interconnection agreements, (b) fund the debt service reserve requirement and the operation and maintenance debt service reserve requirement, (c) provide security for our remediation and mitigation liabilities, and (d) provide security in respect of our conditional use permit sales tax obligations.

In January 2012, MEHC, through a wholly-owned subsidiary, acquired from NRG Energy, Inc. a 49 percent equity interest in Agua Caliente Solar, LLC ("Agua Caliente"), the owner of a 290-MW solar project (the "Agua Caliente Project") in Arizona. The Agua Caliente Project is expected to cost approximately $1.8 billion and will be completed in 12 blocks with an aggregate tested capacity of 310 MW. The first 30-MW block of the Agua Caliente Project was placed in service in January 2012 and the Agua Caliente Project expects to place 112 additional MW in service in 2012, 136 MW in service in 2013 and 32 MW in service in 2014. The project is being constructed pursuant to a fixed price, date certain, turn-key engineering, procurement and construction contract with a subsidiary of First Solar. Agua Caliente will sell all the electricity, renewable energy credits and other environmental attributes produced by the project to PG&E pursuant to a 25 year power purchase agreement. A subsidiary of First Solar will operate and maintain the project under a 25 year, fixed-fee operating and maintenance agreement. Construction costs are expected to be funded with equity contributions from MEHC and NRG Energy, Inc. and proceeds from a $967 million secured loan maturing in 2037 from an agency of the United States government as part of the United States Department of Energy loan guarantee program. Funding requests are submitted on a monthly basis and the approved loans accrue interest at a fixed rate based on the current average yield of comparable maturity United States Treasury rates plus a spread of 0.375%.

Pursuant to an equity funding and contribution agreement, MEHC has committed to provide Agua Caliente with funding for (a) base equity contributions of up to an aggregative amount of $303 million for the construction of the project, and (b) transmission upgrade costs. In January 2012, MEHC entered into a $303 million letter of credit facility related to its funding commitments. The equity funding and contribution agreement and the letter of credit commitment decreases as equity is contributed to the Agua Caliente Project.

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

At the end of the period covered by this Annual Report on Form 10-K, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon that evaluation, the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that the Company's disclosure controls and procedures were effective to ensure that information required to be disclosed by the Company in the reports that it files or submits 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 management, including the Company's Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. There has been no change in the Company's internal control over financial reporting during the quarter ended December 31, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Securities Exchange Act of 1934 Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), the Company's management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2011 as required by the Securities Exchange Act of 1934 Rule 13a-15(c). In making this assessment, the Company's management used the criteria set forth in the framework in "Internal Control - Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation conducted under the framework in "Internal Control - Integrated Framework," the Company's management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

MidAmerican Energy Holdings Company
February 27, 2012

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

MEHC is a consolidated subsidiary of Berkshire Hathaway. Each director was elected based on individual responsibilities, experience in the energy industry and functional expertise. MEHC's Board of Directors appoints executive officers annually. There are no family relationships among the executive officers, nor, except as set forth in employment agreements, any arrangements or understandings between any executive officer and any other person pursuant to which the executive officer was appointed. Set forth below is certain information, as of January 31, 2012, with respect to the current directors and executive officers of MEHC:

GREGORY E. ABEL, 49, Chairman of the Board of Directors since 2011, Chief Executive Officer since 2008, director since 2000, and President since 1998. Mr. Abel joined MEHC in 1992 and has extensive executive management experience in the energy industry. Mr. Abel is also a director of PacifiCorp.

PATRICK J. GOODMAN, 45, Senior Vice President and Chief Financial Officer since 1999. Mr. Goodman joined MEHC in 1995. Mr. Goodman is also a director of PacifiCorp and a Manager of MidAmerican Funding, LLC.

DOUGLAS L. ANDERSON, 53, Senior Vice President, General Counsel and Corporate Secretary since 2001. Mr. Anderson joined MEHC in 1993. Mr. Anderson is also a director of PacifiCorp and a Manager of MidAmerican Funding, LLC.

MAUREEN E. SAMMON, 48, Senior Vice President and Chief Administrative Officer since 2007. Ms. Sammon has been employed by MEHC and its predecessor companies since 1986 and has held several positions, including Vice President, Human Resources and Insurance.

WARREN E. BUFFETT, 81, Director. Mr. Buffett has been a director of MEHC since 2000 and has been Chairman of the Board of Directors and Chief Executive Officer of Berkshire Hathaway for more than five years. Mr. Buffett previously served as a director of The Washington Post Company and The Coca-Cola Company. Mr. Buffett has significant experience as Chairman and Chief Executive Officer of Berkshire Hathaway.

WALTER SCOTT, JR., 80, Director. Mr. Scott has been a director of MEHC since 1991 and has been Chairman of the Board of Directors of Level 3 Communications, Inc., a successor to certain businesses of Peter Kiewit & Sons', Inc., for more than five years. Mr. Scott is also a director of Peter Kiewit & Sons', Inc., Berkshire Hathaway and Valmont Industries, Inc. and previously served as a director of Burlington Resources, Inc. and Commonwealth Telephone Enterprises, Inc. Mr. Scott has significant experience and financial expertise as a past chief executive officer and as a director of both public and private corporations and as chairman of a major charitable foundation.

MARC D. HAMBURG, 62, Director. Mr. Hamburg has been a director of MEHC since 2000 and has been Chief Financial Officer of Berkshire Hathaway for more than five years. Mr. Hamburg was a Vice President of Berkshire Hathaway between 1992 and 2008 and since 2008 has been a Senior Vice President. Mr. Hamburg was Berkshire Hathaway's Treasurer from 1987-2010. Mr. Hamburg has significant financial experience, including expertise in mergers and acquisitions; accounting; treasury; and tax functions.

Board's Role in the Risk Oversight Process

MEHC's Board of Directors is comprised of a combination of MEHC senior management, Berkshire Hathaway senior executives and MEHC owners who have responsibility for the management and oversight of risk. MEHC's Board of Directors has not established a separate risk management and oversight committee.

Audit Committee and Audit Committee Financial Expert

The audit committee of the Board of Directors is comprised of Mr. Marc D. Hamburg. The Board of Directors has determined that Mr. Hamburg qualifies as an "audit committee financial expert," as defined by SEC rules, based on his education, experience and background. Based on the standards of the New York Stock Exchange LLC, on which the common stock of MEHC's majority owner, Berkshire Hathaway, is listed, MEHC's Board of Directors has determined that Mr. Hamburg is not independent because of his employment by Berkshire Hathaway.

Code of Ethics

MEHC has adopted a code of ethics that applies to its principal executive officer, its principal financial and accounting officer, or persons acting in such capacities, and certain other covered officers. The code of ethics is incorporated by reference in the exhibits to this Annual Report on Form 10-K.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

We believe that the compensation paid to each of our Chairman, President and Chief Executive Officer, or Chairman and CEO, our Chief Financial Officer, or CFO, and our other most highly compensated executive officers, to whom we refer collectively as our Named Executive Officers, or NEOs, should be closely aligned with our overall performance, and each NEO's contribution to that performance, on both a short- and long-term basis, and that such compensation should be sufficient to attract and retain highly qualified leaders who can create significant value for our organization. Our compensation programs are designed to provide our NEOs meaningful incentives for superior corporate and individual performance. Performance is evaluated on a subjective basis within the context of both financial and non-financial objectives that we believe contribute to our long-term success, among which are customer service, operational excellence, financial strength, employee commitment and safety, environmental respect and regulatory integrity.

How is Compensation Determined

Our Compensation Committee is comprised of Messrs. Warren E. Buffett and Walter Scott, Jr. The Compensation Committee is responsible for the establishment and oversight of our compensation policy. Approval of compensation decisions for our NEOs is made by the Compensation Committee, unless specifically delegated. Although the Compensation Committee reviews each NEO's complete compensation package at least annually, it has delegated to the Chairman and CEO authority to approve off-cycle pay changes, performance awards and participation in other employee benefit plans and programs for the other NEOs.

Our criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. We do not specifically use other companies as benchmarks when establishing our NEOs' compensation. Subsequently, the Compensation Committee reviews peer company data when making annual base salary and incentive recommendations for the Chairman and CEO. The peer companies for 2011 were American Electric Power Company, Inc., Consolidated Edison, Inc., Dominion Resources, Inc., Edison International, Energy Future Holdings Corp., Entergy Corporation, Exelon Corporation, FirstEnergy Corp., NextEra Energy, Inc., PG&E Corporation, Progress Energy, Inc., Public Service Enterprise Group Incorporated, Sempra Energy, The Southern Company and Xcel Energy Inc.

We engage the compensation practice of Towers Watson & Co., or Towers Watson, to research and document the peer company data to be reviewed by the Compensation Committee when making annual base salary and incentive recommendations for the Chairman and CEO. The fee paid to Towers Watson for this service was $7,874 in 2011. We also engage Towers Watson to provide other services unrelated to executive compensation, including actuarial and consulting services related to our retirement plans. These services are approved by senior management and the aggregate fees paid to Towers Watson for these services were $1,074,186 in 2011. Our Board of Directors is not involved in the selection or approval of Towers Watson for these services.

Discussion and Analysis of Specific Compensation Elements

Base Salary

We determine base salaries for all of our NEOs by reviewing our overall performance and each NEO's performance, the value each NEO brings to us and general labor market conditions. While base salary provides a base level of compensation intended to be competitive with the external market, the annual base salary adjustment for each NEO is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria.

In late 2010, the former Chairman of the Board of Directors and the current Chairman and CEO (then the CEO) together made recommendations regarding the other NEOs' base salaries. The former Chairman made recommendations regarding the current Chairman and CEO's base salary, and the Compensation Committee set the former Chairman's base salary. Following the former Chairman's resignation in April 2011, the Chairman and CEO makes recommendations regarding the other NEOs' base salaries, and the Compensation Committee sets the Chairman and CEO's base salary. All merit increases are approved by the Compensation Committee and take effect on January 1 of each year. An increase or decrease in base salary may also result from a promotion or other significant change in a NEO's responsibilities during the year. In 2011, base salaries for all NEOs increased on average by 1.8% effective January 1, 2011. There were no other base salary changes for our NEOs during the year after the January 1, 2011 merit increase.

Short-Term Incentive Compensation

The objective of short-term incentive compensation is to reward the achievement of significant annual corporate goals while also providing NEOs with competitive total cash compensation.

Performance Incentive Plan

Under our Performance Incentive Plan, or PIP, all NEOs are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis and is not based on a specific formula or cap. A variety of factors are considered in determining each NEO's annual incentive award including the NEO's performance, our overall performance and each NEO's contribution to that overall performance. An individual NEO's performance is evaluated using financial and non-financial principles, including customer service; operational excellence; financial strength; employee commitment and safety; environmental respect; and regulatory integrity, as well as the NEO's response to issues and opportunities that arise during the year. No factor was individually material to the determination of the amounts paid to each NEO under the PIP for 2011. The Chairman and CEO recommends annual incentive awards for the other NEOs to the Compensation Committee prior to the last committee meeting of each year, held in the fourth quarter. The Compensation Committee determines the Chairman and CEO's award. If approved by the Compensation Committee, awards are paid prior to year-end.

Performance Awards

In addition to the annual awards under the PIP, we may grant cash performance awards periodically during the year to one or more NEOs to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and are approved by the Chairman and CEO, as delegated by the Compensation Committee. In December 2011, awards were granted to Messrs. Goodman and Anderson in recognition of their efforts related to certain acquisition activities. Although Mr. Abel is eligible for performance awards, he has not been granted an award in the past five years.

Long-Term Incentive Compensation

The objective of long-term incentive compensation is to retain NEOs, reward their exceptional performance and motivate them to create long-term, sustainable value. Our current long-term incentive compensation program is cash-based. We have not issued stock options or other forms of equity-based awards since March 2000. All stock options previously held by Messrs. Abel and Sokol have been exercised and are no longer outstanding.

Long-Term Incentive Partnership Plan

The MidAmerican Energy Holdings Company Long-Term Incentive Partnership Plan, or LTIP, is designed to retain key employees and to align our interests and the interests of the participating employees. Messrs. Goodman and Anderson and Ms. Sammon, as well as 90 other employees, participate in this plan, while our Chairman and CEO does not. Our former Chairman did not participate in the plan. Our LTIP provides for annual discretionary awards based upon significant accomplishments by the individual participants and the achievement of the financial and non-financial objectives previously described. The goals are developed with the objective of being attainable with a sustained, focused and concerted effort and are determined and communicated in January of each plan year. Participation is discretionary and is determined by the Chairman and CEO who recommends awards to the Compensation Committee annually in the fourth quarter. Except for limited situations of extraordinary performance, awards are capped at 1.5 times base salary and finalized in the first quarter of the following year. These cash-based awards are subject to mandatory deferral and equal annual vesting over a five-year period starting in the performance year. Participants allocate the value of their deferral accounts among various investment alternatives. Gains or losses may be incurred based on investment performance. Participating NEOs may elect to defer all or a part of the award or receive payment in cash after the five-year mandatory deferral and vesting period. Vested balances (including any investment gains or losses thereon) of terminating participants are paid at the time of termination.

Incremental Profit Sharing Plan

The Incremental Profit Sharing Plan, or IPSP, is designed to align our interests and the interests of the Chairman and CEO. The IPSP provides for a cash award based upon our achievement of a specified adjusted diluted earnings per share, or EPS, target for any calendar year. The EPS targets to achieve the award were established by the Compensation Committee in 2009 and are to be achieved no later than calendar year end 2013. The individual profit sharing award that may be earned is $12 million if our EPS is greater than $23.14 per share, but less than or equal to $24.24 per share, $25 million if our EPS is greater than $24.24 per share, but less than $25.37 per share, or $40 million if our EPS is greater than $25.37 per share. Following his resignation, Mr. Sokol is no longer eligible to receive awards under the IPSP. Messrs. Goodman and Anderson and Ms. Sammon do not participate in this plan.

Other Employee Benefits

Supplemental Executive Retirement Plan

The MidAmerican Energy Company Supplemental Executive Retirement Plan for Designated Officers, or SERP, provides additional retirement benefits to participants. We include the SERP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package and as a key retention tool. Messrs. Abel, Goodman and Sokol participate in the SERP, and we have no plans to add new participants in the future. The SERP provides annual retirement benefits of up to 65% of a participant's total cash compensation in effect immediately prior to retirement, subject to an annual $1 million maximum retirement benefit. Total cash compensation means (a) the highest amount payable to a participant as monthly base salary during the five years immediately prior to retirement multiplied by 12, plus (b) the average of the participant's annual awards under an annual incentive bonus program during the three years immediately prior to the year of retirement and (c) special, additional or non-recurring bonus awards, if any, that are required to be included in total cash compensation pursuant to a participant's employment agreement or approved for inclusion by the Board of Directors. All participating NEOs have met the five-year service requirement under the plan. Mr. Goodman's SERP benefit will be reduced by the amount of his regular retirement benefit under the MidAmerican Energy Company Retirement Plan, his actuarially equivalent benefit under the fixed 401(k) contribution option and ratably for retirement between ages 55 and 65.

Deferred Compensation Plan

The MidAmerican Energy Holdings Company Executive Voluntary Deferred Compensation Plan, or DCP, provides a means for all NEOs to make voluntary deferrals of up to 50% of base salary and 100% of short-term incentive compensation awards. We include the DCP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package. The deferrals and any investment returns grow on a tax-deferred basis. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of eight investment options offered under the DCP and selected by the participant. The plan allows participants to choose from three forms of distribution. The plan permits us to make discretionary contributions on behalf of participants; however, we have not made contributions to date.

Financial Planning and Tax Preparation

We reimburse NEOs for financial planning and tax preparation services. The value of the benefit is included in the NEO's taxable income. It is offered both as a competitive benefit itself and also to help ensure our NEOs best utilize the other forms of compensation we provide to them.

Executive Life Insurance

We provide universal life insurance to Messrs. Abel and Goodman, and formerly to Mr. Sokol, having a death benefit of two times annual base salary during employment, reducing to one times annual base salary in retirement. The value of the benefit is included in the NEO's taxable income. We include the executive life insurance as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package.

Potential Payments Upon Termination

Certain NEOs are entitled to post-termination payments in the event their employment is terminated under certain circumstances. We believe these post-termination payments are an important component of the competitive compensation package we offer to these NEOs.

Compensation Committee Report

The Compensation Committee, consisting of Messrs. Buffett and Scott, has reviewed and discussed the Compensation Discussion and Analysis with management and, based on this review and discussion, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Warren E. Buffett
Walter Scott, Jr.

Summary Compensation Table

The following table sets forth information regarding compensation earned by each of our NEOs during the years indicated:

Name and Principal Position	Year	Base Salary	Bonus[1]	Non-Equity Incentive Plan Compensation	Change in Pension Value and Nonqualified Deferred Compensation Earnings[2]	All Other Compensation[3]	Total[4]
Gregory E. Abel, Chairman, President	2011	$ 1,000,000	$ 7,000,000	$ —	$ 1,726,000	$ 187,391	$ 9,913,391
and Chief Executive Officer	2010	1,000,000	6,000,000	—	1,093,000	352,642	8,445,642
	2009	1,000,000	5,000,000	—	890,000	266,699	7,156,699
Patrick J. Goodman, Senior Vice	2011	360,000	1,351,859	—	508,000	36,208	2,256,067
President and Chief Financial	2010	340,000	1,360,900	—	320,000	38,622	2,059,522
Officer	2009	340,000	1,292,543	—	203,000	58,667	1,894,210
Douglas L. Anderson, Senior Vice	2011	310,000	784,316	—	5,000	28,030	1,127,346
President and General Counsel	2010	308,000	905,687	—	4,000	48,329	1,266,016
	2009	308,000	922,618	—	5,000	51,650	1,287,268
Maureen E. Sammon, Senior Vice	2011	226,000	436,045	—	5,000	27,401	694,446
President and Chief	2010	221,000	569,333	—	5,000	38,723	834,056
Administrative Officer	2009	221,000	524,790	—	5,000	37,495	788,285
David L. Sokol, former Chairman of	2011	231,250	—	—	10,134,000	18,649	10,383,899
the Board of Directors[5]	2010	750,000	—	—	1,199,000	50,836	1,999,836
	2009	750,000	6,000,000	—	980,000	252,926	7,982,926

(1) Consists of annual cash incentive awards earned pursuant to the PIP for our NEOs, performance awards earned related to non-routine projects, and the vesting of LTIP awards and associated vested earnings. The breakout for 2011 is as follows:

			LTIP		
	PIP	Performance Award	Vested Awards	Vested Earnings	Total
Gregory E. Abel	$ 7,000,000	$ —	$ —	$ —	$ —
Patrick J. Goodman	425,000	150,000	677,500	99,359	776,859
Douglas L. Anderson	300,000	125,000	352,450	6,866	359,316
Maureen E. Sammon	180,000	—	228,757	27,288	256,045
David L. Sokol	—	—	—	—	—

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid out may increase or decrease depending on investment performance. Net income, the net income target goal and the matrix below were used in determining the gross amount of the LTIP award available to the participants. Net income for determining the award and the award itself are subject to discretionary adjustment by the Chairman and CEO and Compensation Committee. In 2011, the gross award and per-point value were determined based on the overall achievement of our financial and non-financial objectives.

Net Income	Award
Less than or equal to net income target goal	None
Exceeds net income target goal by 0.01% - 6.50%	25% of excess
Exceeds net income target goal by more than 6.50%	25% of the first 6.50% excess; and
	35% of excess over 6.50%

Points are allocated among plan participants either as initial points or year-end performance points. A nominating committee recommends the point allocation, subject to approval by the Chairman and CEO, based upon a discretionary evaluation of individual achievement of financial and non-financial goals previously described herein. A participant's award equals the participants allocated points multiplied by the final per-point value, capped at 1.5 times base salary except in extraordinary circumstances.

(2) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which include our cash balance and SERP, as applicable. Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in our Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and are as of December 31, 2011. No participant in our DCP earned "above-market" or "preferential" earnings on amounts deferred.

(3) Amounts consist of vacation payouts and 401(k) contributions we paid on behalf of the NEOs, as well as perquisites and other personal benefits related to life insurance premiums, the personal use of corporate aircraft and financial planning and tax preparation that we paid on behalf of Messrs. Abel, Goodman, Anderson and Sokol. The personal use of corporate aircraft represents our incremental cost of providing this personal benefit determined by applying the percentage of flight hours used for personal use to our variable expenses incurred from operating our corporate aircraft. All other compensation is based upon amounts paid by us.

Items required to be reported and quantified are as follows: Mr. Abel - personal use of corporate aircraft of $149,785 and 401(k) contributions of $11,638; Mr. Goodman - 401(k) contributions of $27,563; Mr. Anderson - 401(k) contributions of $27,563; and Ms. Sammon - 401(k) contributions of $27,401.

(4) Any amounts voluntarily deferred by the NEO, if applicable, are included in the appropriate column in the summary compensation table.

(5) Mr. Sokol resigned effective April 21, 2011, at which time Mr. Abel, then President and Chief Executive Officer, was appointed Chairman, President and Chief Executive Officer.

Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of our NEOs as of December 31, 2011:

Name	Plan name	Number of years credited service(1)	Present value of accumulated benefit(2)	Payments during last fiscal year(3)
Gregory E. Abel	SERP	n/a	$ 7,717,000	$ —
	MidAmerican Energy Company Retirement Plan	n/a	264,000	—
Patrick J. Goodman	SERP	17 years	1,438,000	—
	MidAmerican Energy Company Retirement Plan	10 years	212,000	—
Douglas L. Anderson	MidAmerican Energy Company Retirement Plan	10 years	218,000	—
Maureen E. Sammon	MidAmerican Energy Company Retirement Plan	22 years	245,000	—
David L. Sokol	SERP	n/a	16,912,000	750,000
	MidAmerican Energy Company Retirement Plan	n/a	—	301,687

(1) The pension benefits for Messrs. Abel and Sokol do not depend on their years of service, as both have already reached their maximum benefit levels based on their respective ages and previous triggering events described in their employment agreements. Mr. Goodman's credited years of service, for purposes of the SERP only, includes 13 years of service with us and four additional years of imputed service from a predecessor company.

(2) Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in our Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and are as of December 31, 2011, which is the measurement date for the plans. The present value of accumulated benefits for the SERP was calculated using the following assumptions: (1) Mr. Abel - a 100% joint and survivor annuity; (2) Mr. Goodman - a 66 2/3% joint and survivor annuity; and (3) Mr. Sokol - a 100% joint and survivor annuity. The present value of accumulated benefits for the MidAmerican Energy Company Retirement Plan was calculated using a lump sum payment assumption. The present value assumptions used in calculating the present value of accumulated benefits for both the SERP and the MidAmerican Energy Company Retirement Plan were as follows: a cash balance interest crediting rate of 0.81% in 2012 and 4.00% thereafter; a cash balance conversion rate of 4.75% in 2012 and thereafter; a discount rate of 4.75%; an expected retirement age of 65; postretirement mortality as prescribed by Internal Revenue Code Section 430(h)(3)(A) tables, separated by annuitant and non-annuitants; and cash balance conversion mortality using the Notice 2008-85 tables.

(3) Mr. Sokol's post-termination SERP benefit is $1 million annually, paid in monthly installments. He elected a one-time lump sum payment of his MidAmerican Energy Company Retirement Plan benefit of $301,687, which was paid to him on May 1, 2011.

The SERP provides annual retirement benefits up to 65% of a participant's total cash compensation in effect immediately prior to retirement, subject to an annual $1 million maximum retirement benefit. Total cash compensation means (i) the highest amount payable to a participant as monthly base salary during the five years immediately prior to retirement multiplied by 12, plus (ii) the average of the participant's awards under an annual incentive bonus program during the three years immediately prior to the year of retirement and (iii) special, additional or non-recurring bonus awards, if any, that are required to be included in total cash compensation pursuant to a participant's employment agreement or approved for inclusion by the Board of Directors. Mr. Goodman's SERP benefit will be reduced by the amount of his regular retirement benefit under the MidAmerican Energy Company Retirement Plan, his actuarially equivalent benefit under the fixed 401(k) contribution option and ratably for retirement between ages 55 and 65. A survivor benefit is payable to a surviving spouse under the SERP. Benefits from the SERP will be paid out of general corporate funds; however, through a Rabbi trust, we maintain life insurance on participants in amounts expected to be sufficient to fund the after-tax cost of the projected benefits. Deferred compensation is considered part of the salary covered by the SERP.

Under the MidAmerican Energy Company Retirement Plan, each NEO has an account, for record-keeping purposes only, to which credits are allocated annually based upon a percentage of the NEO's base salary and incentive paid in the plan year. In addition, all balances in the accounts of NEOs earn a fixed rate of interest that is credited annually. The interest rate for a particular year is based on the one-year constant maturity Treasury yield plus seven-tenths of one percentage point. Each NEO is vested in the MidAmerican Energy Company Retirement Plan. At retirement, or other termination of employment, an amount equal to the vested balance then credited to the account is payable to the NEO in the form of a lump sum or an annuity.

In 2008, non-union employee participants in the MidAmerican Energy Company Retirement Plan were offered the option to continue to receive pay credits in the MidAmerican Energy Company Retirement Plan or receive equivalent fixed contributions to the MidAmerican Energy Company Retirement Savings Plan, or 401(k) plan, with any such election becoming effective January 1, 2009. Messrs. Goodman and Anderson and Ms. Sammon elected the equivalent fixed 401(k) contribution option and, therefore, no longer receive pay credits in the MidAmerican Energy Company Retirement Plan; however, they each continue to receive interest credits.

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the nonqualified deferred compensation plan accounts held by each of our NEOs at December 31, 2011:

Name	Executive contributions in 2011[1]	Registrant contributions in 2011	Aggregate earnings in 2011	Aggregate withdrawals/ distributions	Aggregate balance as of December 31, 2011[2][3]
Gregory E. Abel	$ 350,000	$ —	$ (9,445)	$ —	$ 1,977,363
Patrick J. Goodman	—	—	(3,613)	—	1,007,302
Douglas L. Anderson	588,790	—	(34,906)	(55,763)	2,370,016
Maureen E. Sammon	276,538	—	(6,897)	—	1,370,026
David L. Sokol	—	—	—		—

(1) The contribution amount shown for Mr. Abel is included in the 2011 total compensation reported for him in the Summary Compensation Table and is not additional earned compensation. The contribution amounts shown for Mr. Anderson and Ms. Sammon include $397,111 and $189,471, respectively, earned toward their 2007 LTIP awards prior to 2011. Therefore, these amounts are not included in the 2011 total compensation reported for Mr. Anderson and Ms. Sammon, respectively, in the Summary Compensation Table.

(2) The aggregate balance as of December 31, 2011 shown for Messrs. Abel and Anderson and Ms. Sammon includes $300,000, $278,682 and $173,467, respectively, of compensation previously reported in 2010 in the Summary Compensation Table, and $250,000, $245,233 and $194,118, respectively, of compensation previously reported in 2009 in the Summary Compensation Table.

(3) Excludes the value of 10,041 shares of our common stock reserved for issuance to Mr. Abel. Mr. Abel deferred the right to receive the value of these shares pursuant to a legacy nonqualified deferred compensation plan.

Eligibility for our DCP is restricted to select management and highly compensated employees. The plan provides tax benefits to eligible participants by allowing them to defer compensation on a pretax basis, thus reducing their current taxable income. Deferrals and any investment returns grow on a tax-deferred basis, thus participants pay no income tax until they receive distributions. The DCP permits participants to make a voluntary deferral of up to 50% of base salary and 100% of short-term incentive compensation awards. All deferrals are net of social security taxes. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of eight investment options offered by the plan and selected by the participant. Gains or losses are calculated daily, and returns are posted to accounts based on participants' fund allocation elections. Participants can change their fund allocations as of the end of any day on which the market is open.

The DCP allows participants to maintain three accounts based upon when they want to receive payments: retirement account, in-service account and education account. Both the retirement and in-service accounts can be distributed as lump sums or in up to 10 annual installments. The education account is distributed in four annual installments. If a participant leaves employment prior to retirement (age 55) all amounts in the participant's account will be paid out in a lump sum as soon as administratively practicable. Participants are 100% vested in their deferrals and any investment gains or losses recorded in their accounts.

Participants in our LTIP also have the option of deferring all or a part of those awards after the five-year mandatory deferral and vesting period. The provisions governing the deferral of LTIP awards are similar to those described for the DCP above.

Potential Payments Upon Termination

We have entered into employment agreements with Messrs. Abel, Goodman and Sokol that provide for payments following termination of employment under various circumstances, which do not include change-in-control provisions.

A termination of employment of either Messrs. Abel or Goodman will occur upon his resignation (with or without good reason), permanent disability, death, or termination by us with or without cause. Mr. Sokol's employment terminated upon his resignation in April 2011.

The employment agreements for Messrs. Abel and Sokol also include provisions specific to the calculation of their respective SERP benefits.

Neither Mr. Anderson nor Ms. Sammon has an employment agreement. Where a NEO does not have an employment agreement, or in the event that the agreements for Messrs. Abel, Goodman and Sokol do not address an issue, payments upon termination are determined by the applicable plan documents and our general employment policies and practices as discussed below.

The following discussion provides further detail on post-termination payments.

Gregory E. Abel

Mr. Abel's employment agreement entitles him to receive two years base salary continuation and payments in respect of average bonuses for the prior two years in the event we terminate his employment other than for cause. The payments are to be paid as a lump sum with no discount for present valuation.

In addition, if Mr. Abel's employment is terminated due to death, permanent disability or other than for cause, he is entitled to continuation of his senior executive employee benefits (or the economic equivalent thereof) for two years. If Mr. Abel resigns, we must pay him any accrued but unpaid base salary, unless he resigns for good reason, in which case he will receive the same benefits as if he were terminated other than for cause.

Payments made in accordance with the employment agreement are contingent on Mr. Abel complying with the confidentiality and post-employment restrictions described therein. The term of the agreement effectively expires on August 6, 2016, and is extended automatically for additional one year terms thereafter subject to Mr. Abel's election to decline renewal at least 365 days prior to the August 6 that is four years prior to the current expiration date (or by August 6, 2012 for the agreement not to extend to August 6, 2017).

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) and nonqualified deferred compensation account balances and those portions of life insurance benefits and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2011, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance[1]	Incentive	Life Insurance[2]	Pension[3]	Benefits Continuation[4]	Excise and Other Taxes[5]
Retirement, Voluntary and Involuntary With Cause	$ —	$ —	$ —	$ 10,980,000	$ —	$ —
Involuntary Without Cause, Disability and Voluntary With Good Reason	15,000,000	—	—	10,980,000	54,244	—
Death	15,000,000	—	1,923,475	10,432,000	54,244	—

(1) The cash severance payments are determined in accordance with Mr. Abel's employment agreement.

(2) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by us.

(3) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table. Mr. Abel's death scenario is based on a 100% joint and survivor with 15-year certain annuity commencing immediately. Mr. Abel's other termination scenarios are based on a 100% joint and survivor annuity commencing immediately.

(4) Includes health and welfare, life insurance and financial planning and tax preparation benefits for two years. The health and welfare benefit amounts are estimated using the rates we currently charge employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Abel would have paid if he had continued his employment. The life insurance benefit amounts are based on the cost of individual policies offering benefits equivalent to our group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire two year period, with no offset by another employer. We will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for two years or pay a lump sum cash amount to keep Mr. Abel in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement. If it is determined that benefits paid with respect to the extension of medical and dental benefits to Mr. Abel would not be exempt from taxation under the Internal Revenue Code, we shall pay to Mr. Abel a lump sum cash payment following separation from service to allow him to obtain equivalent medical and dental benefits and which would put him in the same after-tax economic position.

(5) As provided in Mr. Abel's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments subject to an excise tax, we will gross up such payments to cover the excise tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, we do not believe that any of the termination scenarios are subject to any excise tax.

Patrick J. Goodman

Mr. Goodman's employment agreement entitles him to receive two years base salary continuation and payments in respect of average bonuses for the prior two years in the event we terminate his employment other than for cause. The payments are to be paid as a lump sum with no discount for present valuation.

In addition, if Mr. Goodman's employment is terminated due to death, permanent disability or other than for cause, he is entitled to continuation of his senior executive employee benefits (or the economic equivalent thereof) for one year. If Mr. Goodman resigns, we must pay him any accrued but unpaid base salary, unless he resigns for good reason, in which case he will receive the same benefits as if he were terminated other than for cause.

Payments made in accordance with the employment agreement are contingent on Mr. Goodman complying with the confidentiality and post-employment restrictions described therein. The term of the agreement expires on April 21, 2013, but is extended automatically for additional one year terms thereafter subject to Mr. Goodman's election to decline renewal at least 365 days prior to the then current expiration date or termination.

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401 (k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments, life insurance benefits and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2011, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance[1]	Incentive[2]	Life Insurance[3]	Pension[4]	Benefits Continuation[5]	Excise and Other Taxes[6]
Retirement and Voluntary	$ —	$ —	$ —	$ 983,000	$ —	$ —
Involuntary With Cause	—	—	—	—	—	—
Involuntary Without Cause and Voluntary With Good Reason	3,095,000	—	—	983,000	16,952	—
Death	3,095,000	1,452,616	697,747	3,815,000	16,952	—
Disability	3,095,000	1,452,616	—	2,576,000	16,952	—

(1) The cash severance payments are determined in accordance with Mr. Goodman's employment agreement.

(2) Amounts represent the unvested portion of Mr. Goodman's LTIP account, which becomes 100% vested upon his death or disability.

(3) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by us.

(4) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table. Mr. Goodman's voluntary termination, retirement, involuntary without cause, and change in control termination scenarios are based on a 66 2/3% joint and survivor annuity commencing at age 55 (reductions for termination prior to age 55 and commencement prior to age 65). Mr. Goodman's disability scenario is based on a 66 2/3% joint and survivor annuity commencing at age 55 (no reduction for termination prior to age 55, reduced for commencement prior to age 65). Mr. Goodman's death scenario is based on a 15-year certain only annuity commencing immediately (no reduction for termination prior to age 55 and commencement prior to age 65).

(5) Includes health and welfare, life insurance and financial planning and tax preparation benefits for one year. The health and welfare benefit amounts are estimated using the rates we currently charge employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Goodman would have paid if he had continued his employment. The life insurance benefit amounts are based on the cost of individual policies offering benefits equivalent to our group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire one year period, with no offset by another employer. We will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for one year or pay a lump sum cash amount to keep Mr. Goodman in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement.

(6) As provided in Mr. Goodman's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments subject to an excise tax, we will gross up such payments to cover the excise tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, we do not believe that any of the termination scenarios are subject to any excise tax.

Douglas L. Anderson

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401 (k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2011, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance	Incentive[1]	Life Insurance	Pension[2]	Benefits Continuation	Excise and Other Taxes
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ —	$ —	$ 26,000	$ —	$ —
Death and Disability	—	606,451	—	26,000	—	—

(1) Amounts represent the unvested portion of Mr. Anderson's LTIP account, which becomes 100% vested upon his death or disability.

(2) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table.

Maureen E. Sammon

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401 (k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2011, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance	Incentive[1]	Life Insurance	Pension[2]	Benefits Continuation	Excise and Other Taxes
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ —	$ —	$ 40,000	$ —	$ —
Death and Disability	—	434,837	—	40,000	—	—

(1) Amounts represent the unvested portion of Ms. Sammon's LTIP account, which becomes 100% vested upon her death or disability.

(2) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table.

David L. Sokol

Mr. Sokol resigned effective April 21, 2011. In accordance with the terms of his employment agreement, no cash severance, incentive payment or continuation of benefits was owed to him. He elected to cash out his executive life insurance policy and was paid $97,686 on November 1, 2011, following our release of the collateral assignment. His post-termination SERP benefit is $1 million annually, paid in monthly installments. He elected a one-time lump sum payment of his MidAmerican Energy Company Retirement Plan benefit in the amount of $301,687, which was paid to him on May 1, 2011.

Director Compensation

Our directors are not paid any fees for serving as directors. All directors are reimbursed for their expenses incurred in attending Board of Directors meetings.

Compensation Committee Interlocks and Insider Participation

Mr. Buffett is the Chairman of the Board of Directors and Chief Executive Officer of Berkshire Hathaway, our majority owner. Mr. Scott is a former officer of ours. Based on the standards of the New York Stock Exchange LLC, on which the common stock of our majority owner, Berkshire Hathaway, is listed, our Board of Directors has determined that Messrs. Buffett and Scott are not independent because of their ownership of our common stock. None of our executive officers serves as a member of the compensation committee of any company that has an executive officer serving as a member of our Board of Directors. None of our executive officers serves as a member of the board of directors of any company that has an executive officer serving as a member of our Compensation Committee. See also Item 13 of this Form 10-K.

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

Beneficial Ownership

We are a consolidated subsidiary of Berkshire Hathaway. The balance of our common stock is owned by Mr. Scott (along with family members and related entities) and Mr. Abel. The following table sets forth certain information regarding beneficial ownership of our shares of common stock held by each of our directors, executive officers and all of our directors and executive officers as a group as of January 31, 2012:

Name and Address of Beneficial Owner(1)	Number of Shares Beneficially Owned(2)	Percentage Of Class(2)
Berkshire Hathaway(3)	67,035,061	89.85%
Walter Scott, Jr.(4)	4,200,000	5.63%
Gregory E. Abel	595,940	0.80%
Douglas L. Anderson	—	—
Warren E. Buffett(5)	—	—
Patrick J. Goodman	—	—
Marc D. Hamburg(5)	—	—
Maureen E. Sammon	—	—
All directors and executive officers as a group (7 persons)	4,795,940	6.43%

(1) Unless otherwise indicated, each address is c/o MidAmerican Energy Holdings Company at 666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309.

(2) Includes shares of which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

(3) Such beneficial owner's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

(4) Excludes 2,778,000 shares held by family members and family controlled trusts and corporations, or Scott Family Interests, as to which Mr. Scott disclaims beneficial ownership. Mr. Scott's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(5) Excludes 67,035,061 shares of common stock held by Berkshire Hathaway as to which Messrs. Buffett and Hamburg disclaim beneficial ownership.

The following table sets forth certain information regarding beneficial ownership of Class A and Class B shares of Berkshire Hathaway's common stock held by each of our directors, executive officers and all of our directors and executive officers as a group as of January 31, 2012:

Name and Address of Beneficial Owner(1)	**Number of Shares Beneficially Owned**(2)	**Percentage Of Class**(2)
Walter Scott, Jr.(3)(4)		
Class A	100	*
Class B	—	—
Gregory E. Abel(4)		
Class A	5	*
Class B	2,289	*
Douglas L. Anderson		
Class A	4	*
Class B	300	*
Warren E. Buffett(5)		
Class A	350,000	37.3%
Class B	26,153,883	2.5%
Patrick J. Goodman		
Class A	4	*
Class B	660	*
Marc D. Hamburg		
Class A	—	—
Class B	—	—
Maureen E. Sammon		
Class A	—	—
Class B	3,102	*
All directors and executive officers as a group (7 persons)		
Class A	350,113	37.3%
Class B	26,160,234	2.5%

* Less than 1%

(1) Unless otherwise indicated, each address is c/o MidAmerican Energy Holdings Company at 666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309.

(2) Includes shares which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

(3) Does not include 10 Class A shares owned by Mr. Scott's wife. Mr. Scott's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(4) In accordance with a shareholders agreement, as amended on December 7, 2005, based on an assumed value for our common stock and the closing price of Berkshire Hathaway common stock on January 31, 2012, Mr. Scott and the Scott Family Interests and Mr. Abel would be entitled to exchange their shares of our common stock for either 15,089 and 1,289, respectively, shares of Berkshire Hathaway Class A stock or 22,704,989 and 1,939,067, respectively, shares of Berkshire Hathaway Class B stock. Assuming an exchange of all available MEHC shares into either Berkshire Hathaway Class A shares or Berkshire Hathaway Class B shares, Mr. Scott and the Scott Family Interests would beneficially own 1.6% of the outstanding shares of Berkshire Hathaway Class A stock or 2.1% of the outstanding shares of Berkshire Hathaway Class B stock, and Mr. Abel would beneficially own less than 1% of the outstanding shares of either class of stock.

(5) Mr. Buffett's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

Other Matters

Pursuant to a shareholders' agreement, as amended on December 7, 2005, Mr. Scott or any of the Scott Family Interests and Mr. Abel are able to require Berkshire Hathaway to exchange any or all of their respective shares of our common stock for shares of Berkshire Hathaway common stock. The number of shares of Berkshire Hathaway common stock to be exchanged is based on the fair market value of our common stock divided by the closing price of the Berkshire Hathaway common stock on the day prior to the date of exchange.

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

Certain Relationships and Related Transactions

The Berkshire Hathaway Inc. Code of Business Conduct and Ethics and the MEHC Code of Business Conduct, or the Codes, which apply to all of our directors, officers and employees and those of our subsidiaries, generally govern the review, approval or ratification of any related-person transaction. A related-person transaction is one in which we or any of our subsidiaries participate and in which one or more of our directors, executive officers, holders of more than five percent of our voting securities or any of such persons' immediate family members have a direct or indirect material interest.

Under the Codes, all of our directors and executive officers (including those of our subsidiaries) must disclose to our legal department any material transaction or relationship that reasonably could be expected to give rise to a conflict with our interests. No action may be taken with respect to such transaction or relationship until approved by the legal department. For our chief executive officer and chief financial officer, prior approval for any such transaction or relationship must be given by Berkshire Hathaway's audit committee. In addition, prior legal department approval must be obtained before a director or executive officer can accept employment, offices or board positions in other for-profit businesses, or engage in his or her own business that raises a potential conflict or appearance of conflict with our interests. Transactions with Berkshire Hathaway require the approval of our Board of Directors.

As of December 31, 2011 and 2010, Berkshire Hathaway and its affiliates held 11% mandatorily redeemable preferred securities due from certain of our wholly owned subsidiary trusts with liquidation preferences of $22 million and $165 million, respectively. Principal repayments and interest expense on these securities totaled $143 million and $13 million, respectively, during 2011.

Director Independence

Based on the standards of the New York Stock Exchange LLC, on which the common stock of our majority owner, Berkshire Hathaway, is listed, our Board of Directors has determined that none of our directors are considered independent because of their employment by Berkshire Hathaway or us or their ownership of our common stock.

Item 14. Principal Accountant Fees and Services

The following table shows the Company's fees paid or accrued for audit and audit-related services and fees paid for tax and all other services rendered by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, the "Deloitte Entities") for each of the last two years (in millions):

	2011	2010
Audit fees(1)	$ 4.5	$ 4.4
Audit-related fees(2)	0.7	0.6
Tax fees(3)	0.2	0.2
All other fees	—	—
Total	$ 5.4	$ 5.2

(1) Audit fees include fees for the audit of the Company's consolidated financial statements and interim reviews of the Company's quarterly financial statements, audit services provided in connection with required statutory audits of certain of MEHC's subsidiaries and comfort letters, consents and other services related to SEC matters.

(2) Audit-related fees primarily include fees for assurance and related services for any other statutory or regulatory requirements, audits of certain subsidiary employee benefit plans and consultations on various accounting and reporting matters.

(3) Tax fees include fees for services relating to tax compliance, tax planning and tax advice. These services include assistance regarding federal, state and international tax compliance, tax return preparation and tax audits.

The audit committee has considered whether the non-audit services provided to the Company by the Deloitte Entities impaired the independence of the Deloitte Entities and concluded that they did not. All of the services performed by the Deloitte Entities were pre-approved in accordance with the pre-approval policy adopted by the audit committee. The policy provides guidelines for the audit, audit-related, tax and other non-audit services that may be provided by the Deloitte Entities to the Company. The policy (a) identifies the guiding principles that must be considered by the audit committee in approving services to ensure that the Deloitte Entities' independence is not impaired; (b) describes the audit, audit-related and tax services that may be provided and the non-audit services that are prohibited; and (c) sets forth pre-approval requirements for all permitted services. Under the policy, requests to provide services that require specific approval by the audit committee will be submitted to the audit committee by both MEHC's independent auditor and its Chief Financial Officer. All requests for services to be provided by the independent auditor that do not require specific approval by the audit committee will be submitted to MEHC's Chief Financial Officer and must include a detailed description of the services to be rendered. The Chief Financial Officer will determine whether such services are included within the list of services that have received the general pre-approval of the audit committee. The audit committee will be informed on a timely basis of any such services rendered by the independent auditor.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

(i) Financial Statements

Consolidated Financial Statements are included in Item 8. 80

(ii) Financial Statement Schedules

See Schedule I. 155
See Schedule II. 159

Schedules not listed above have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(b) Exhibits

The exhibits listed on the accompanying Exhibit Index are filed as part of this Annual Report. 162

(c) Financial statements required by Regulation S-X, which are excluded from the Annual Report by Rule 14a-3(b).

Not applicable.

MidAmerican Energy Holdings Company
Parent Company Only
Condensed Balance Sheets
As of December 31, 2011 and 2010
(Amounts in millions)

	2011	2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13	$ 18
Accounts receivable	3	25
Accounts receivable - affiliate	—	10
Income taxes receivable	127	—
Other current assets	13	13
Total current assets	156	66
Investments in subsidiaries	19,483	18,841
Other investments	588	1,276
Goodwill	1,289	1,289
Other assets	548	195
Total assets	$ 22,064	$ 21,667
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	$ 163	$ 140
Short-term debt	108	284
Current portion of senior debt	742	—
Current portion of subordinated debt	22	143
Total current liabilities	1,035	567
Senior debt	4,621	5,371
Subordinated debt	—	172
Notes payable - affiliate	1,963	1,841
Other long-term liabilities	346	478
Total liabilities	7,965	8,429
Equity:		
MEHC shareholders' equity:		
Common stock - 115 shares authorized, no par value, 75 shares issued and outstanding	—	—
Additional paid-in capital	5,423	5,427
Retained earnings	9,310	7,979
Accumulated other comprehensive loss, net	(641)	(174)
Total MEHC shareholders' equity	14,092	13,232
Noncontrolling interest	7	6
Total equity	14,099	13,238
Total liabilities and equity	$ 22,064	$ 21,667

The accompanying notes are an integral part of this financial statement schedule.

MidAmerican Energy Holdings Company
Parent Company Only (continued)
Condensed Statements of Operations
For the three years ended December 31, 2011
(Amounts in millions)

	2011	2010	2009
Operating costs and expenses:			
General and administration	35	42	172
Depreciation and amortization	—	—	1
Total costs and expenses	35	42	173
Operating loss	(35)	(42)	(173)
Other income (expense):			
Interest expense	(396)	(425)	(449)
Interest and dividend income	2	12	5
Other, net	(40)	11	10
Total other income (expense)	(434)	(402)	(434)
Loss before income tax benefit and equity income	(469)	(444)	(607)
Income tax benefit	(194)	(220)	(253)
Equity income	1,607	1,462	1,511
Net income	1,332	1,238	1,157
Net income attributable to noncontrolling interest	1	—	—
Net income attributable to MEHC	$ 1,331	$ 1,238	$ 1,157

The accompanying notes are an integral part of this financial statement schedule.

MidAmerican Energy Holdings Company
Parent Company Only (continued)
Condensed Statements of Cash Flows
For the three years ended December 31, 2011
(Amounts in millions)

	2011	2010	2009
Cash flows from operating activities	$ 792	$ (47)	$ 285
Cash flows from investing activities:			
Investments in subsidiaries	(157)	(214)	(202)
Notes receivable from affiliate, net	(217)	240	(195)
Purchases of available-for-sale securities	(38)	(15)	(253)
Proceeds from sale of available-for-sale securities	33	20	8
Other, net	(6)	—	(1)
Net cash flows from investing activities	(385)	31	(643)
Cash flows from financing activities:			
Proceeds from senior debt	—	—	250
Repayments of subordinated debt	(334)	(281)	(734)
Net (repayments of) proceeds from short-term debt	(176)	234	(166)
Notes payable to affiliate, net	106	120	1,144
Net purchases of common stock	—	(56)	(123)
Other, net	(8)	—	(2)
Net cash flows from financing activities	(412)	17	369
Net change in cash and cash equivalents	(5)	1	11
Cash and cash equivalents at beginning of year	18	17	6
Cash and cash equivalents at end of year	$ 13	$ 18	$ 17

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN ENERGY HOLDINGS COMPANY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are MEHC and Subsidiaries Consolidated Statements of Changes in Equity for the three years ended December 31, 2011 in Part II, Item 8.

Basis of Presentation - The condensed financial information of MidAmerican Energy Holdings Company's ("MEHC") investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in subsidiaries are recorded in the Condensed Balance Sheets. The income from operations of subsidiaries is reported on a net basis as equity income in the Condensed Statements of Operations.

Other investments - MEHC's investment in BYD Company Limited ("BYD") common stock is accounted for as an available-for-sale security with changes in fair value recognized in AOCI. As of December 31, 2011 and 2010, the fair value of MEHC's investment in BYD common stock was $488 million and $1.182 billion, respectively, which resulted in a pre-tax unrealized gain of $256 million and $950 million as of December 31, 2011 and 2010, respectively.

Dividends and distributions from subsidiaries - Cash dividends paid to MEHC by its subsidiaries for the years ended December 31, 2011, 2010 and 2009 were $1.088 billion, $433 million and $495 million, respectively. In January and February 2012, MEHC received cash dividends from its subsidiaries totaling $252 million.

General and administration - In March 2009, 703,329 common stock options were exercised having an exercise price of $35.05 per share, or $25 million. Also in March 2009, MEHC purchased the shares issued from the options exercised for $148 million. As a result, MEHC recognized $125 million of stock-based compensation expense, including MEHC's share of payroll taxes, for the year ended December 31, 2009.

Guarantees

MEHC has issued a limited guarantee of a specified portion of the final scheduled principal payment on December 15, 2019 on the Cordova Funding Corporation senior secured bonds in an amount up to a maximum of $37 million.

See the notes to the consolidated MEHC financial statements in Part II, Item 8 for other disclosures.

MIDAMERICAN ENERGY HOLDINGS COMPANY
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2011

(Amounts in millions)

Column A Description	Column B Balance at Beginning of Year	Column C Charged to Income	Column C Acquisition Reserves	Column D Deductions	Column E Balance at End of Year
Reserves Deducted From Assets To Which They Apply:					
Reserve for uncollectible accounts receivable:					
Year ended 2011	$ 27	$ 19	$ —	$ (25)	$ 21
Year ended 2010	25	24	—	(22)	27
Year ended 2009	24	28	1	(28)	25
Reserves Not Deducted From Assets[1]:					
Year ended 2011	$ 8	$ 4	$ —	$ (4)	$ 8
Year ended 2010	9	4	—	(5)	8
Year ended 2009	9	4	—	(4)	9

The notes to the consolidated MEHC financial statements are an integral part of this financial statement schedule.

(1) Reserves not deducted from assets relate primarily to estimated liabilities for losses retained by MEHC for workers compensation, public liability and property damage claims.

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 on this 27th day of February 2012.

MIDAMERICAN ENERGY HOLDINGS COMPANY

/s/ Gregory E. Abel*
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal 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/ Gregory E. Abel* Gregory E. Abel	Chairman, President and Chief Executive Officer (principal executive officer)	February 27, 2012
/s/ Patrick J. Goodman* Patrick J. Goodman	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 27, 2012
/s/ Walter Scott, Jr.* Walter Scott, Jr.	Director	February 27, 2012
/s/ Marc D. Hamburg* Marc D. Hamburg	Director	February 27, 2012
/s/ Warren E. Buffett* Warren E. Buffett	Director	February 27, 2012
*By: /s/ Douglas L. Anderson Douglas L. Anderson	Attorney-in-Fact	February 27, 2012

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

No annual report to security holders covering MidAmerican Energy Holdings Company's last fiscal year or proxy material has been sent to security holders.

EXHIBIT INDEX

Exhibit No.	Description
3.1	Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective March 2, 2006 (incorporated by reference to Exhibit 3.1 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2005).
3.2	Amended and Restated Bylaws of MidAmerican Energy Holdings Company (incorporated by reference to Exhibit 3.2 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.1	Indenture, dated as of October 4, 2002, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee, relating to the 5.875% Senior Notes due 2012 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
4.2	First Supplemental Indenture, dated as of October 4, 2002, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee, relating to the 5.875% Senior Notes due 2012 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
4.3	Second Supplemental Indenture, dated as of May 16, 2003, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee, relating to the 3.50% Senior Notes due 2008 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Holdings Company Registration Statement No. 333-105690 dated May 23, 2003).
4.4	Third Supplemental Indenture, dated as of February 12, 2004, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee, relating to the 5.00% Senior Notes due 2014 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Holdings Company Registration Statement No. 333-113022 dated February 23, 2004).
4.5	Fourth Supplemental Indenture, dated as of March 24, 2006, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.125% Senior Bonds due 2036 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated March 28, 2006).
4.6	Fifth Supplemental Indenture, dated as of May 11, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 5.95% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated May 11, 2007).
4.7	Sixth Supplemental Indenture, dated as of August 28, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.50% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated August 28, 2007).
4.8	Seventh Supplemental Indenture, dated as of March 28, 2008, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., as Trustee, relating to the 5.75% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated March 28, 2008).
4.9	Eighth Supplemental Indenture, dated as of July 7, 2009, by and between MidAmerican Energy Holdings Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 3.15% Senior Notes due 2012 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated July 7, 2009).

Exhibit No.	Description
4.10	Indenture, dated as of October 15, 1997, by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated October 23, 1997).
4.11	Form of Second Supplemental Indenture, dated as of September 22, 1998 by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee, relating to the 8.48% Senior Notes in the principal amount of $475,000,000 due 2028 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated September 17, 1998).
4.12	Indenture, dated as of March 12, 2002, by and between MidAmerican Energy Holdings Company and the Bank of New York, Trustee (incorporated by reference to Exhibit 4.11 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2001).
4.13	Amended and Restated Declaration of Trust of MidAmerican Capital Trust II, dated as of March 12, 2002 (incorporated by reference to Exhibit 4.15 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
4.14	Indenture and First Supplemental Indenture, dated March 11, 1999, by and between MidAmerican Funding, LLC and IBJ Whitehall Bank & Trust Company, Trustee, relating to the $700 million Senior Notes and Bonds (incorporated by reference to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 1998).
4.15	Form of Indenture, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Registration Statement No. 333-59760 dated January 31, 2002).
4.16	First Supplemental Indenture, dated as of February 8, 2002, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 333-15387).
4.17	Second Supplemental Indenture, dated as of January 14, 2003, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 333-15387).
4.18	Third Supplemental Indenture, dated as of October 1, 2004, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 333-15387).
4.19	Fourth Supplemental Indenture, dated November 1, 2005, by and between MidAmerican Energy Company and the Bank of New York Trust Company, NA, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.20	Fiscal Agency Agreement, dated as of October 15, 2002, by and between Northern Natural Gas Company and J.P. Morgan Trust Company, National Association, Fiscal Agent, relating to the $300,000,000 in principal amount of the 5.375% Senior Notes due 2012 (incorporated by reference to Exhibit 10.47 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2003).
4.21	Trust Indenture, dated as of August 13, 2001, among Kern River Funding Corporation, Kern River Gas Transmission Company and JP Morgan Chase Bank, Trustee, relating to the $510,000,000 in principal amount of the 6.676% Senior Notes due 2016 (incorporated by reference to Exhibit 10.48 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2003).
4.22	Third Supplemental Indenture, dated as of May 1, 2003, among Kern River Funding Corporation, Kern River Gas Transmission Company and JPMorgan Chase Bank, Trustee, relating to the $836,000,000 in principal amount of the 4.893% Senior Notes due 2018 (incorporated by reference to Exhibit 10.49 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2003).

Exhibit No.	Description
4.23	Trust Deed, dated December 15, 1997 among CE Electric UK Funding Company, AMBAC Insurance UK Limited and The Law Debenture Trust Corporation, p.l.c., Trustee (incorporated by reference to Exhibit 99.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated March 30, 2004).
4.24	Insurance and Indemnity Agreement, dated December 15, 1997 by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.2 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated March 30, 2004).
4.25	Supplemental Agreement to Insurance and Indemnity Agreement, dated September 19, 2001, by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.3 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated March 30, 2004).
4.26	Fiscal Agency Agreement, dated as of July 15 2008, by and between Northern Natural Gas Company and The Bank New York Mellon Trust Company, National Association, Fiscal Agent, relating to the $200,000,000 in principal amount of the 5.75% Senior Notes due 2018 (incorporated by reference to Exhibit 4.32 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2008).
4.27	Fiscal Agency Agreement, dated as of April 20, 2011, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the $200,000,000 in principal amount of the 4.25% Senior Notes due 2021.
4.28	Trust Indenture, dated as of September 10, 1999, by and between Cordova Funding Corporation and Chase Manhattan Bank and Trust Company, National Association, Trustee, relating to the $225,000,000 in principal amount of the 8.75% Senior Secured Bonds due 2019 (incorporated by reference to Exhibit 10.71 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.29	Trust Deed, dated as of February 4, 1998 among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.74 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.30	First Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.75 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.31	Third Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Electricity Distribution plc, Yorkshire Electricity Group plc and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 9.25% Bonds due 2020 (incorporated by reference to Exhibit 10.76 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.32	Indenture, dated as of February 1, 2000, among Yorkshire Power Finance 2 Limited, Yorkshire Power Group Limited and The Bank of New York, Trustee (incorporated by reference to Exhibit 10.78 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.33	First Supplemental Trust Deed, dated as of September 27, 2001, among Northern Electric Finance plc, Northern Electric plc, Northern Electric Distribution Limited and The Law Debenture Trust Corporation p.l.c., Trustee, relating to the £100,000,000 in principal amount of the 8.875% Guaranteed Bonds due 2020 (incorporated by reference to Exhibit 10.81 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.34	Trust Deed, dated as of January 17, 1995, by and between Yorkshire Electricity Group plc and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 9 1/4% Bonds due 2020 (incorporated by reference to Exhibit 10.83 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).

Exhibit No.	**Description**
4.35	Master Trust Deed, dated as of October 16, 1995, by and between Northern Electric Finance plc, Northern Electric plc and The Law Debenture Trust Corporation p.l.c., Trustee, relating to the £100,000,000 in principal amount of the 8.875% Guaranteed Bonds due 2020 (incorporated by reference to Exhibit 10.70 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2004).
4.36	Fiscal Agency Agreement, dated April 14, 2005, by and between Northern Natural Gas Company and J.P. Morgan Trust Company, National Association, Fiscal Agent, relating to the $100,000,000 in principal amount of the 5.125% Senior Notes due 2015 (incorporated by reference to Exhibit 99.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated April 18, 2005).
4.37	Trust Deed dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.1 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.38	Reimbursement and Indemnity Agreement dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.2 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.39	Trust Deed, dated May 5, 2005 among Yorkshire Electricity Distribution plc, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.3 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.40	Reimbursement and Indemnity Agreement, dated May 5, 2005 between Yorkshire Electricity Distribution plc and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.4 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.41	Supplemental Trust Deed, dated May 5, 2005 among CE Electric UK Funding Company, Ambac Assurance UK Limited and The Law Debenture Trust Corporation plc (incorporated by reference to Exhibit 99.5 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.42	Second Supplemental Agreement to Insurance and Indemnity Agreement, dated May 5, 2005 by and between CE Electric UK Funding Company and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.6 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.43	Shareholders Agreement, dated as of March 14, 2000 (incorporated by reference to Exhibit 4.19 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
4.44	Amendment No. 1 to Shareholders Agreement, dated December 7, 2005 (incorporated by reference to Exhibit 4.17 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.45	Equity Commitment Agreement, dated as of March 1, 2006, by and between Berkshire Hathaway Inc. and MidAmerican Energy Holdings Company (incorporated by reference to Exhibit 10.72 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.46	Amendment No. 1 to Equity Commitment Agreement, dated March 23, 2010, by and between Berkshire Hathaway Inc. and MidAmerican Energy Holdings Company (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated March 23, 2010).
4.47	Fiscal Agency Agreement, dated February 12, 2007, by and between Northern Natural Gas Company and Bank of New York Trust Company, N.A., Fiscal Agent, relating to the $150,000,000 in principal amount of the 5.80% Senior Bonds due 2037 (incorporated by reference to Exhibit 99.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated February 12, 2007).

Exhibit No.	Description
4.48	Indenture, dated as of October 1, 2006, by and between MidAmerican Energy Company and the Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4.49	First Supplemental Indenture, dated as of October 6, 2006, by and between MidAmerican Energy Company and the Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4.50	Second Supplemental Indenture, dated June 29, 2007, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated June 29, 2007).
4.51	Third Supplemental Indenture, dated March 25, 2008, by and between MidAmerican Energy Company and The Bank of New York Trust Company, Trustee, relating to the 5.3% Notes due 2018 (incorporated by reference to Exhibit 4.1 to MidAmerican Energy Company Current Report on Form 8-K dated March 25, 2008).
4.52	£119,000,000 Finance Contract, dated July 2, 2010, by and between Northern Electric Distribution Limited and the European Investment Bank (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.53	Guarantee and Indemnity Agreement, dated July 2, 2010, by and between CE Electric UK Funding Company and the European Investment Bank (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.54	£151,000,000 Finance Contract, dated July 2, 2010, by and between Yorkshire Electricity Distribution plc and the European Investment Bank (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.55	Guarantee and Indemnity Agreement, dated July 2, 2010, by and between CE Electric UK Funding Company and the European Investment Bank (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.56	Indenture, dated as of February 24, 2012, by and between Topaz Solar Farms LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee.

Exhibit No.	**Description**
4.57	Mortgage and Deed of Trust dated as of January 9, 1989, between PacifiCorp and The Bank of New York Mellon Trust Company, N.A., Trustee, incorporated by reference to Exhibit 4-E, Form 8-B, File No. 1-5152, as supplemented and modified by 25 Supplemental Indentures, each incorporated by reference, as follows:

Exhibit Number	PacifiCorp File Type	File Date	File Number
(4)(b)	SE	November 2, 1989	33-31861
(4)(a)	8-K	January 9, 1990	1-5152
4(a)	8-K	September 11, 1991	1-5152
4(a)	8-K	January 7, 1992	1-5152
4(a)	10-Q	Quarter ended March 31, 1992	1-5152
4(a)	10-Q	Quarter ended September 30, 1992	1-5152
4(a)	8-K	April 1, 1993	1-5152
4(a)	10-Q	Quarter ended September 30, 1993	1-5152
(4)b	10-Q	Quarter ended June 30, 1994	1-5152
(4)b	10-K	Year ended December 31, 1994	1-5152
(4)b	10-K	Year ended December 31, 1995	1-5152
(4)b	10-K	Year ended December 31, 1996	1-5152
4(b)	10-K	Year ended December 31, 1998	1-5152
99(a)	8-K	November 21, 2001	1-5152
4.1	10-Q	Quarter ended June 30, 2003	1-5152
99	8-K	September 8, 2003	1-5152
4	8-K	August 24, 2004	1-5152
4	8-K	June 13, 2005	1-5152
4.2	8-K	August 14, 2006	1-5152
4	8-K	March 14, 2007	1-5152
4.1	8-K	October 3, 2007	1-5152
4.1	8-K	July 17, 2008	1-5152
4.1	8-K	January 8, 2009	1-5152
4.1	8-K	May 12, 2011	1-5152
4.1	8-K	January 6, 2012	1-5152

Exhibit No.	**Description**
10.1	Amended and Restated Employment Agreement, dated February 25, 2008, by and between MidAmerican Energy Holdings Company and Gregory E. Abel (incorporated by reference to Exhibit 10.3 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.2	Incremental Profit Sharing Plan, dated February 10, 2009, by and between MidAmerican Energy Holdings Company and Gregory E. Abel (incorporated by reference to Exhibit 10.6 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2008).
10.3	Amended and Restated Employment Agreement, dated February 25, 2008, by and between MidAmerican Energy Holdings Company and Patrick J. Goodman (incorporated by reference to Exhibit 10.5 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2007).

Exhibit No.	Description
10.4	Amended and Restated Casecnan Project Agreement, dated June 26, 1995, between the National Irrigation Administration and CE Casecnan Water and Energy Company Inc. (incorporated by reference to Exhibit 10.1 to the CE Casecnan Water and Energy Company, Inc. Registration Statement on Form S-4 dated January 25, 1996).
10.5	Supplemental Agreement, dated as of September 29, 2003, by and between CE Casecnan Water and Energy Company, Inc. and the Philippines National Irrigation Administration (incorporated by reference to Exhibit 98.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated October 15, 2003).
10.6	CalEnergy Company, Inc. Voluntary Deferred Compensation Plan, effective December 1, 1997, First Amendment, dated as of August 17, 1999, and Second Amendment effective March 14, 2000 (incorporated by reference to Exhibit 10.50 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
10.7	MidAmerican Energy Holdings Company Executive Voluntary Deferred Compensation Plan restated effective as of January 1, 2007 (incorporated by reference to Exhibit 10.9 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.8	MidAmerican Energy Company First Amended and Restated Supplemental Retirement Plan for Designated Officers dated as of May 10, 1999 amended on February 25, 2008 to be effective as of January 1, 2005 (incorporated by reference to Exhibit 10.10 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.9	MidAmerican Energy Holdings Company Long-Term Incentive Partnership Plan as Amended and Restated January 1, 2007 (incorporated by reference to Exhibit 10.11 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.10	Amended and Restated Credit Agreement, dated as of July 6, 2006, by and among MidAmerican Energy Holdings Company, as Borrower, The Banks and Other Financial Institutions Parties Hereto, as Banks, JPMorgan Chase Bank, N.A., as L/C Issuer, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland PLC, as Syndication Agent, and ABN Amro Bank N.V., JPMorgan Chase Bank, N.A. and BNP Paribas as Co-Documentation Agents (incorporated by reference to Exhibit 99.1 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.11	First Amendment, dated as of April 15, 2009, to the Amended and Restated Credit Agreement, dated as of July 6, 2006, by and among MidAmerican Energy Holdings Company, as Borrower, The Banks and Other Financial Institutions Parties Hereto, as Banks, JPMorgan Chase Bank, N.A., as L/C Issuer, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland PLC, as Syndication Agent, and ABN Amro Bank N.V., JPMorgan Chase Bank, N.A. and BNP Paribas as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.12	Amended and Restated Credit Agreement, dated as of July 6, 2006, among MidAmerican Energy Company, the Lending Institutions Party Hereto, as Banks, Union Bank of California, N.A., as Syndication Agent, JPMorgan Chase Bank, N.A., as Administrative Agent, and The Royal Bank of Scotland plc, ABN AMRO Bank N.V. and BNP Paribas as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.13	First Amendment, dated as of April 15, 2009, to the Amended and Restated Credit Agreement, dated as of July 6, 2006, by and among MidAmerican Energy Company, the Lending Institutions Party Hereto, as Banks, Union Bank of California, N.A., as Syndication Agent, JPMorgan Chase Bank, N.A., as Administrative Agent, and The Royal Bank of Scotland plc, ABN AMRO Bank N.V. and BNP Paribas as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.14	$700,000,000 Credit Agreement dated as of October 23, 2007 among PacifiCorp, The Banks Party thereto, The Royal Bank of Scotland plc, as Syndication Agent, and Union Bank of California, N.A., as Administrative Agent (incorporated by reference to Exhibit 99 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).

Exhibit No.	Description
10.15	First Amendment, dated as of April 15, 2009, to the $700,000,000 Credit Agreement dated as of October 23, 2007 among PacifiCorp, The Banks Party thereto, The Royal Bank of Scotland plc, as Syndication Agent, and Union Bank of California, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.16	$800,000,000 Amended and Restated Credit Agreement dated as of July 6, 2006 among PacifiCorp, The Banks Party thereto, The Royal Bank of Scotland plc, as Syndication Agent, and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by Reference to Exhibit 99 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.17	First Amendment, dated as of April 15, 2009, to the $800,000,000 Amended and Restated Credit Agreement dated as of July 6, 2006 among PacifiCorp, The Banks Party thereto, The Royal Bank of Scotland plc, as Syndication Agent, and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.18	Second Amendment dated as of January 6, 2012, amends that certain Amended and Restated Credit Agreement, dated as of July 6, 2006, among PacifiCorp, the banks listed on the signature pages thereto, JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, and the Royal Bank of Scotland plc, as Syndication Agent (incorporated by reference to Exhibit 10.11 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2011).
10.19	£150,000,000 Facility Agreement, dated March 26, 2010, among CE Electric UK Funding Company, Yorkshire Electricity Distribution plc and Northern Electric Distribution Limited, as Borrowers, and Abbey National Treasury Services plc, Lloyds TSB Bank plc and The Royal Bank of Scotland plc, as Original Lenders (incorporated by reference to Exhibit 10.1 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2010).
10.20	$500,000,000 Revolving Loan Agreement, dated January 6, 2012, between MidAmerican Energy Holdings Company and BH Finance LLC.
10.21	Summary of Key Terms of Compensation Arrangements with MidAmerican Energy Holdings Company Named Executive Officers and Directors.
14.1	MidAmerican Energy Holdings Company Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2003).
21.1	Subsidiaries of the Registrant.
23.1	Consent of Deloitte & Touche LLP.
24.1	Power of Attorney.
31.1	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Coal Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Exhibit No.	**Description**
101	The following financial information from MidAmerican Energy Holdings Company's Annual Report on Form 10-K for the year ended December 31, 2011 is formatted in XBRL (eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Changes in Equity, (v) the Consolidated Statements of Comprehensive Income and (vi) the Notes to Consolidated Financial Statements, tagged as blocks of text.

EXHIBIT 10.21

SUMMARY OF KEY TERMS OF COMPENSATION ARRANGEMENTS WITH MIDAMERICAN ENERGY HOLDINGS COMPANY NAMED EXECUTIVE OFFICERS AND DIRECTORS

MidAmerican Energy Holdings Company's ("MEHC") continuing named executive officers each receive an annual salary and participate in health insurance and other benefit plans on the same basis as other employees, as well as certain other compensation and benefit plans described in MEHC's Annual Report on Form 10-K.

The named executive officers are also eligible to receive a cash incentive award under MEHC's Performance Incentive Plan ("PIP"). The PIP provides for a discretionary annual cash award that is determined on a subjective basis and paid in December. In addition to the PIP, the named executive officers are eligible to receive discretionary cash performance awards periodically during the year to reward the accomplishment of significant non-recurring tasks or projects. Mr. Gregory E. Abel has not been granted discretionary cash performance awards in the past five years. Messrs. Patrick J. Goodman and Douglas L. Anderson and Ms. Maureen E. Sammon are participants in MEHC's Long-Term Incentive Partnership Plan ("LTIP"). Mr. Abel does not participate in the LTIP. A copy of the LTIP is attached as Exhibit 10.9 to the MEHC Annual Report on Form 10-K. Mr. Abel is a participant in MEHC's Incremental Profit Sharing Plan ("IPSP"). Messrs. Goodman and Anderson and Ms. Sammon do not participate in the IPSP. A copy of Mr. Abel's IPSP is attached as Exhibit 10.2 to the MEHC Annual Report on Form 10-K.

Base salary for continuing named executive officers for MEHC's fiscal year ending December 31, 2012, is shown in the following table:

Name and Title	Base Salary
Gregory E. Abel Chairman, President and Chief Executive Officer	$ 1,000,000
Patrick J. Goodman Senior Vice President and Chief Financial Officer	$ 367,500
Douglas L. Anderson Senior Vice President and General Counsel	$ 315,000
Maureen E. Sammon Senior Vice President and Chief Administrative Officer	$ 230,000

Mr. Abel is a director of MEHC, but does not receive additional compensation for his service as a director other than what he receives as an employee of MEHC. The other members of the MEHC board of directors do not receive compensation for their service as directors.

EXHIBIT 21.1

MIDAMERICAN ENERGY HOLDINGS COMPANY
SUBSIDIARIES AND JOINT VENTURES

Pursuant to Item 601(b)(21)(ii) of Regulation S-K, we have omitted dormant subsidiaries (all of which, when considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary as of the end of our last fiscal year).

MidAmerican Funding, LLC	Iowa
MHC Inc.	Iowa
MidAmerican Energy Company	Iowa
Century Development, LLC	Iowa
CBEC Railway Inc.	Iowa
Cimmred Leasing Company	South Dakota
MHC Investment Company	South Dakota
MWR Capital Inc.	South Dakota
Midwest Capital Group, Inc.	Iowa
Dakota Dunes Development Company	Iowa
Two Rivers Inc.	South Dakota
MEC Construction Services Co.	Iowa
Northern Powergrid Holdings Company	England
CalEnergy Gas (Holdings) Limited	England
CalEnergy Gas Limited	England
CalEnergy Resources Limited	England
CalEnergy Resources Poland Sp. z.o.o.	Poland
CalEnergy Resources (Australia) Limited	England
CE Electric (Ireland) Limited	Ireland
CE Electric UK Holdings	England
ElectraLink Limited	England
Northern Powergrid Limited	England
CE UK Gas Holdings Limited	England
Integrated Utility Services Limited	England
Integrated Utility Services Limited	Ireland
Northern Electric plc.	England
Northern Powergrid (Northeast) Limited	England
Northern Electric Finance plc.	England
Northern Electric & Gas Limited	England
Northern Electric Properties Limited	England
Northern Transport Finance Limited	England
Vehicle Lease and Service Limited	England
Northern Powergrid (Yorkshire) plc.	England
Yorkshire Electricity Group plc.	England
Yorkshire Power Finance Limited	Grand Cayman
Yorkshire Power Group Limited	England
HomeServices of America, Inc.	Delaware
Arizona Home Services, L.L.C.	Arizona
Caldwell Mill, LLP	Alabama
California Premiere Lending, LLC	Delaware
California Title Company	California
Capitol Title Company	Nebraska

CBSHOME Real Estate Company	Nebraska
CBSHOME Real Estate of Iowa, Inc.	Delaware
CBSHOME Relocation Services, Inc.	Nebraska
CBSHOME Insurance, LLC	Nebraska
Champion Realty, Inc.	Maryland
Chancellor Title Services, Inc.	Maryland
Columbia Title of Florida, Inc.	Florida
CJR Realtors, LLC	Delaware
Edina Financial Services, Inc.	Minnesota
Edina Realty, Inc.	Minnesota
Edina Realty Insurance, LLC	Delaware
Edina Realty Referral Network, Inc.	Minnesota
Edina Realty Relocation, Inc.	Minnesota
Edina Realty Title, Inc.	Minnesota
Esslinger-Wooten-Maxwell, Inc.	Florida
E-W-M Referral Services, Inc.	Florida
FFR, Inc.	Iowa
First Realty, Ltd.	Iowa
For Rent, Inc.	Arizona
Fort Dearborn Land Title Company, LLC	Delaware
HMSV Financial Services, Inc.	Delaware
HN Heritage Title Holdings, LLC	Georgia
HN Insurance Services, LLC	Georgia
HN Real Estate Group, L.L.C.	Georgia
HN Real Estate Group, N.C., Inc.	North Carolina
HN Referral Corporation	Georgia
Home Services Referral Network, LLC	Indiana
HomeServices Financial Holdings, Inc.	Delaware
HomeServices Lending, LLC	Delaware
HomeServices Insurance, Inc.	Nebraska
HomeServices Insurance Agency, LLC	Delaware
HomeServices of Alabama, Inc.	Delaware
HomeServices of California, Inc.	Delaware
HomeServices of Florida, Inc.	Florida
HomeServices of Illinois, LLC	Delaware
HomeServices of Illinois Holdings, LLC	Delaware
HomeServices of Iowa, Inc.	Delaware
HomeServices of Kentucky, Inc.	Kentucky
HomeServices of Kentucky Insurance, LLC	Delaware
HomeServices of Kentucky Real Estate Academy, LLC	Kentucky
HomeServices of Nebraska, Inc.	Delaware
HomeServices of Nebraska Insurance, LLC	Delaware
HomeServices of Oregon, LLC	Delaware
HomeServices of the Carolinas, Inc.	Delaware
HomeServices Relocation, LLC	Delaware
HSR Equity Funding, Inc.	Delaware
Huff Commercial Group, LLC	Kentucky
Huff Realty Insurance, LLC	Delaware
Huff-Drees Realty, Inc.	Ohio
IMO Co., Inc.	Missouri

InsuranceSouth, LLC	Georgia
Iowa Realty Co., Inc.	Iowa
Iowa Realty Insurance Agency, Inc.	Iowa
Iowa Title Company	Iowa
Iowa Title Linn County II, LLC	Iowa
JBRC, Inc.	Kentucky
J. D. Reece Mortgage Company	Kansas
Jim Huff Realty, Inc.	Kentucky
JRHBW Realty, Inc.	Alabama
J. S. White & Associates, Inc.	Alabama
Kansas City Title, Inc.	Missouri
Kentucky Residential Referral Service, LLC	Kentucky
Larabee School of Real Estate and Insurance, Inc.	Nebraska
Lincoln Title Company, LLC	Nebraska
Long Title Agency, LLC	Arizona
Meridian Title Services, LLC	Georgia
Mid-America Referral Network, Inc.	Kansas
Midland Escrow Services, Inc.	Iowa
Nebraska Land Title and Abstract Company	Nebraska
Pickford Escrow Company, Inc.	California
Pickford Holdings LLC	California
Pickford North County L.P.	California
Pickford Real Estate, Inc.	California
Pickford Realty, Ltd.	California
Pickford Services Company	California
Pilot Butte, LLC	Delaware
Plaza Financial Services, L.L.C.	Kansas
Plaza Mortgage Services, L.L.C.	Kansas
Preferred Carolinas Realty, Inc.	North Carolina
Preferred Carolinas Title Agency, L.L.C.	North Carolina
Professional Referral Organization, Inc.	Maryland
Real Estate Links, LLC	Illinois
Real Estate Referral Network, Inc.	Nebraska
Real Referrals, Inc.	Illinois
Reece Commercial, Inc.	Kansas
Reece & Nichols Alliance, Inc.	Kansas
Reece & Nichols Insurance, LLC	Delaware
Reece & Nichols Realtors, Inc.	Kansas
Referral Company of North Carolina, Inc.	North Carolina
Referral Network of IL, LLC	Delaware
RHL Referral Company, L.L.C.	Arizona
Roberts Brothers, Inc.	Alabama
Roy H. Long Realty Company, Inc.	Arizona
San Diego PCRE, Inc.	California
Semonin Realtors, Inc.	Delaware
Southwest Relocation, L.L.C.	Arizona
The Escrow Firm, Inc.	California
The Referral Co.	Iowa
TitleSouth, LLC	Alabama
Township Title Services, LLC	Georgia

Traditions Title Agency, LLC	Ohio
Wahoo Title, LLC	Nebraska
Wm Broughton, LLC	Delaware
CE Generation, LLC	Delaware
CalEnergy Operating Corporation	Delaware
California Energy Development Corporation	Delaware
California Energy Yuma Corporation	Utah
CE Salton Sea Inc.	Delaware
CE Texas Power, L.L.C.	Delaware
CE Texas Resources, L.L.C.	Delaware
CE Turbo LLC	Delaware
Conejo Energy Company	California
Del Ranch Company	California
Desert Valley Company	California
Falcon Power Operating Company	Texas
CE Gen Oil Company	Texas
CE Gen Pipeline Corporation	Texas
CE Gen Power Corporation	Texas
Fish Lake Power LLC	Delaware
FSRI Holdings, Inc.	Texas
Imperial Magma LLC	Delaware
CE Leathers Company	California
Magma Land Company I	Nevada
Magma Power Company	Nevada
Niguel Energy Company	California
North Country Gas Pipeline Corporation	New York
Power Resources, Ltd.	Texas
Salton Sea Brine Processing Company	California
Salton Sea Funding Corporation	Delaware
Salton Sea Power Company	Nevada
Salton Sea Power Generation Company	California
Salton Sea Power L.L.C.	Delaware
Salton Sea Royalty Company	Delaware
San Felipe Energy Company	California
Saranac Energy Company, Inc.	Delaware
Saranac Power Partners, L.P.	Delaware
SECI Holdings, Inc.	Delaware
Selectusonline Limited	England
VPC Geothermal LLC	Delaware
Vulcan Power Company	Nevada
Vulcan/BN Geothermal Power Company	Nevada
Yuma Cogeneration Associates	Utah
BG Energy Holding LLC	Delaware
CalEnergy Generation Operating Company	Delaware
CalEnergy International Services, Inc.	Delaware
CalEnergy Investments C.V.	Netherlands
CalEnergy Minerals LLC	Delaware
CalEnergy Pacific Holdings Corp.	Delaware
CalEnergy U.K. Inc.	Delaware
CE Casecnan Ltd.	Bermuda

CE Casecnan II, Inc.	Philippines
CE Casecnan Water and Energy Company, Inc.	Philippines
CE Electric (NY), Inc.	Delaware
CE Electric, Inc.	Delaware
CE Exploration Company	Delaware
CE Geothermal, Inc.	Delaware
CE Insurance Services Limited	Isle of Man
CE International Investments, Inc.	Delaware
CE Philippines II, Inc.	Philippines
CE Philippines Ltd.	Bermuda
CE Power, Inc.	Delaware
Tongonan Power Investment, Inc.	Philippines
Visayas Geothermal Power Company	Philippines
CE Luzon Geothermal Power Company, Inc.	Philippines
CE Mahanagdong II, Inc.	Philippines
CE Black Rock Holdings LLC	Delaware
CE Butte Energy Holdings LLC	Delaware
CE Butte Energy LLC	Delaware
CE Obsidian Holding LLC	Delaware
CE Obsidian Energy LLC	Delaware
CE Red Island Energy Holdings LLC	Delaware
CE Mahanagdong Ltd.	Bermuda
CE Red Island Energy LLC	Delaware
Cordova Energy Company LLC	Delaware
Cordova Funding Corporation	Delaware
Kern River Funding Corporation	Delaware
Kern River Gas Transmission Company	Texas
KR Acquisition 1, LLC	Delaware
KR Acquisition 2, LLC	Delaware
KR Holding, LLC	Delaware
Magma Netherlands B.V.	Netherlands
M & M Ranch Acquisition Company, LLC	Delaware
Alaska Storage Holding Company, LLC	Delaware
Alaska Gas Pipeline Company, LLC	Delaware
Alaska Gas Transmission Company, LLC	Delaware
Cook Inlet Natural Gas Storage Alaska, LLC	Delaware
Cook Inlet Natural Gas Storage, LLC	Delaware
Black Rock 1, LLC	Delaware
Black Rock 2, LLC	Delaware
Black Rock 3, LLC	Delaware
Black Rock 4, LLC	Delaware
Black Rock 5, LLC	Delaware
Black Rock 6, LLC	Delaware
MEHC Investment, Inc.	South Dakota
MEHC Insurance Services Ltd.	Vermont
MEHC America Transco, LLC	Delaware
MEHC Texas Transco, LLC	Delaware
MidAmerican Capital Trust II	Delaware
Electric Transmission America, LLC	Delaware
Prairie Wind Transmission, LLC	Delaware

Tallgrass Transmission, LLC	Delaware
Electric Transmission Texas, LLC	Delaware
MidAmerican Energy Machining Services LLC	Delaware
NNGC Acquisition, LLC	Delaware
Northern Natural Gas Company	Delaware
PPW Holdings LLC	Delaware
PacifiCorp	Oregon
Energy West Mining Company	Utah
PacifiCorp Investment Management, Inc.	Oregon
Glenrock Coal Company	Wyoming
Interwest Mining Company	Oregon
Pacific Minerals, Inc.	Wyoming
PacifiCorp Environmental Remediation Company	Delaware
FOSSIL ROCK FUELS, LLC	Delaware
Trapper Mining Inc.	Delaware
Bridger Coal Company	Wyoming
Quad Cities Energy Company	Iowa
Salton Sea Minerals Corp.	Delaware
S.W. Hydro, Inc.	Delaware
Wailuku Holding Company, LLC	Delaware
Wailuku River Hydroelectric Power Company, Inc.	Hawaii
Wailuku River Hydroelectric Limited Partnership	Hawaii
Bishop Hill II Holdings, LLC	Delaware
Elmore Company	California
MidAmerican AC Holding, LLC	Delaware
NRG Solar AC Holdings LLC	Delaware
Agua Caliente Solar, LLC	Delaware
MidAmerican Geothermal, LLC	Delaware
MidAmerican Hydro, LLC	Delaware
MidAmerican Renewables, LLC	Delaware
MidAmerican Solar, LLC	Delaware
MidAmerican Transmission, LLC	Delaware
MidAmerican Wind, LLC	Delaware
TPZ Holding, LLC	Delaware
Topaz Solar Farms, LLC	Delaware
Racom Corporation	Delaware
RITELine Transmission Development, LLC	Delaware
RITELine Indiana, LLC	Indiana
RITELine Illinois, LLC	Illinois

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-147957 on Form S-8 of our report dated February 27, 2012, relating to the consolidated financial statements and financial statement schedules of MidAmerican Energy Holdings Company and subsidiaries, appearing in this Annual Report on Form 10-K of MidAmerican Energy Holdings Company for the year ended December 31, 2011.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 27, 2012

EXHIBIT 24.1

POWER OF ATTORNEY

The undersigned, a member of the Board of Directors or an officer of MIDAMERICAN ENERGY HOLDINGS COMPANY, an Iowa corporation (the "Company"), hereby constitutes and appoints Douglas L. Anderson and Paul J. Leighton and each of them, as his/her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for and in his/her stead, in any and all capacities, to sign on his/her behalf the Company's Annual Report on Form 10-K for the fiscal year ending December 31, 2011 and to execute any amendments thereto and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission and applicable stock exchanges, with the full power and authority to do and perform each and every act and thing necessary or advisable to all intents and purposes as he/she might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, or his/her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Executed as of February 27, 2012

/s/ Gregory E. Abel
GREGORY E. ABEL

/s/ Warren E. Buffett
WARREN E. BUFFETT

/s/ Walter Scott, Jr.
WALTER SCOTT, JR.

/s/ Patrick J. Goodman
PATRICK J. GOODMAN

/s/ Marc D. Hamburg
MARC D. HAMBURG

EXHIBIT 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Gregory E. Abel, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Energy Holdings Company;

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, 2012

/s/ Gregory E. Abel
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Patrick J. Goodman, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Energy Holdings Company;

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, 2012

/s/ Patrick J. Goodman
Patrick J. Goodman
Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Gregory E. Abel, Chairman, President and Chief Executive Officer of MidAmerican Energy Holdings Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2011 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 27, 2012

/s/ Gregory E. Abel
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

CERTIFICATION PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Patrick J. Goodman, Senior Vice President and Chief Financial Officer of MidAmerican Energy Holdings Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2011 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 27, 2012

/s/ Patrick J. Goodman
Patrick J. Goodman
Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 95

MINE SAFETY VIOLATIONS AND OTHER LEGAL MATTER DISCLOSURES PURSUANT TO SECTION 1503(a) OF THE DODD-FRANK WALL STREET REFORM AND CONSUMER PROTECTION ACT

PacifiCorp and its subsidiaries operate certain coal mines and coal processing facilities (collectively, the "mining facilities") that are regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Safety Act"). MSHA inspects PacifiCorp's mining facilities on a regular basis. The total number of reportable Mine Safety Act citations, orders, assessments and legal actions for the year ended December 31, 2011 are summarized in the table below and are subject to contest and appeal. The severity and assessment of penalties may be reduced or, in some cases, dismissed through the contest and appeal process. Amounts are reported regardless of whether PacifiCorp has challenged or appealed the matter. Coal reserves that are not yet mined and mines that are closed or idled are not included in the information below as no reportable events occurred at those locations during the year ended December 31, 2011. There were no mining-related fatalities during the year ended December 31, 2011.

	Mine Safety Act			Legal Actions		
Mining Facilities	**Section 104 Significant & Substantial Citations[1]**	**Section 104(b) Orders[2]**	**Total Value of Proposed MSHA Assessments (in thousands)**	**Pending[3]**	**Instituted During Period**	**Closed During Period**
Deer Creek	18	—	$ 38	12	9	14
Bridger (surface)	6	—	10	4	3	5
Bridger (underground)	43	1	155	17	11	11
Cottonwood Preparatory Plant	1	—	—	—	—	—
Wyodak Coal Crushing Facility	—	—	—	—	—	—

(1) Citations for alleged violations of mandatory health and safety standards that could significantly or substantially contribute to the cause and effect of a safety or health hazard under Section 104 of the Mine Safety Act.

(2) For alleged failure to totally abate the subject matter of a Mine Safety Act Section 104(a) citation within the period specified in the citation. This order was abated on May 10, 2011.

(3) Amounts are as of December 31, 2011 and (a) include contests of proposed penalties under Subpart C of the Federal Mine Safety and Health Review Commission's procedural rules and (b) are not exclusive to citations, notices, orders and penalties assessed by MSHA during the reporting period.

TAB P-1-1

Overview

Consistent with the Board's designation proceedings and its Phase 1 Decision, the Applicant has prepared cost estimates for the development, construction and O&M of the EWTL. Its cost estimates are based on sound engineering practice, conformity with the Board's Minimum Design Criteria and Minimum Technical Requirements, input from the Applicant's Ontario advisors including Stantec and PowerTel (consultants and construction contractors, respectively), union wage scales, approximately one year of studies, more than 50 person-days of on-site examination of Hydro One's existing East-West Transmission line and adjoining lands, comparison with costs recently incurred by the Applicant for a range of transmission projects in Canada and the US, the Applicant's experience in controlling costs, the Applicant's experience and knowledge of the relationship between estimated and actual costs and consideration of the unique aspects of the Project's development and construction.

All cost estimates in this Exhibit P are in 2013 Canadian dollars and subject to escalation for inflation.

Designation Costs

Mindful of the Board's desire to provide "benefit to ratepayers through economic efficiency [that] reduces costs or risks to ratepayers," the Applicant will not seek reimbursement for the approximate $1.5 million in Designation Costs it has incurred and will incur to prepare this Application, participate in the designation process, and conduct certain early development activities in order to achieve an expedited in-service date, particularly route selection and construction access studies. Such costs are not included in the Project development cost estimates or the Applicant's construction cost estimates in this Exhibit P. The Applicant's Designation Costs are discussed in further detail in Exhibit P-2.

Development Costs

The Applicant's aggregate development costs to be incurred prior to its filing of an application for LTC of the EWTL will be within the range of $20.1 million to $22.9 million, with a base amount of $21.5 million, which the Applicant proposes to the Board for approval as reasonable in this Application for future recovery in rates. These aggregate development costs are applicable to each configuration for the EWTL, discussed in Exhibits G, H and I and, are included within the Project's estimated cost bid amounts. These costs are discussed in further detail in Exhibit P-3.

Table P-1

PRE-LTC PROJECT DEVELOPMENT COSTS (millions, $2013)			
CATEGORY	LOW	BASE AMOUNT	HIGH
Engineering & Design	$9.60	$9.60	$9.60
Project Management & Expenses	$4.30	$4.30	$4.30
Land Control	$2.40	$2.40	$2.40
Consultation & FN Participation	$2.20	$2.20	$2.20
Environmental/Permitting	$1.60	$1.60	$1.60
Contingencies/Risks	$0.00	$1.40	$2.80
TOTALS	$20.10	$21.50	$22.90

The Applicant will cap its project management costs and expenses at $4.3 million. All development costs are subject to escalation by CPI from January 2013 until the date the LTC for the EWTL is filed.

Construction Costs

The Applicant's aggregate costs to be incurred during the Construction Phase of the EWTL will, for the:

- Preferred Design over the Preliminary Preferred Route, be within the range of $341.7 million to $437.7 million, with a base amount of $391.9 million;

- Reference Design over the Preliminary Preferred Route, be within the range of $422.6 million to $518.8 million, with a base amount of $472.2 million;

- Preferred Design over the Reference Route, be within the range of $340.8 million to $436.6 million, with a base amount of $400.4 million;

- Reference Design over the Reference Route, be within the range of $417.1 million to $512.9 million, with a base amount of $476.7 million;

In each case above, the figures include development costs of $11.5 million budgeted for expenditure during the LTC proceedings, in order to achieve an expedited in service date ("**COD**") of year-end 2018 for the EWTL.

The cost estimate breakdown provided in Table P-2 below is in respect of the Applicant's preferred configuration for the EWTL, being the Preferred Design over the Preliminary Preferred Route, with a year-end 2018 COD.

Table P-2

PROJECT CONSTRUCTION COSTS ($2013, millions)			
CATEGORY	LOW	BASE	HIGH
Materials & Supplies	$187.6	$187.6	$187.6
EPC Contractor	$80.4	$80.4	$80.4
Land Control	$13.0	$13.0	$13.0
Engineering & Design	$12.8	$12.8	$12.8
Man Camps & Misc	$12.6	$12.6	$12.6
Site Preparation/Clearing	$11.3	$11.3	$11.3
Construction Inspection/Management	$8.1	$8.1	$8.1
Project Management & Expenses	$7.7	$7.7	$7.7
Environmental/Permitting	$6.2	$6.2	$6.2
Consultation & FN Participation	$2.0	$2.0	$2.0
Contingencies/Risks	$0.0	$50.2	$96.0
TOTALS	$341.7	$391.9	$437.7

These costs are discussed further detail in Exhibit P-4.

Development and Construction Costs for Non-Preferred EWTL Configurations

The Applicant considers its two cost estimates for aggregate Project costs for the EWTL routed on the Preliminary Preferred Route (being in respect of the Preferred Design and the Reference Design) as definitive. The cost estimates for aggregate Project costs for the two Reference Route options set out in Table P-3 below are subject to further refinement, which would be carried out as part of development activities prior to an application for LTC for the EWTL, if the Applicant was to construct the EWTL pursuant to either such option.

Table P-3

		TOTAL PROJECT COSTS (millions, $2013)			
		Reference Route (401 km)		Preliminary Preferred Route (409 km)	
	Circuits	Range	Base Amount	Range	Base Amount
Reference Design	2	$437.2 - $535.8	$498.2	$442.7 - $541.7	$493.7
Preferred Design	1	$360.9 - $459.5	$421.9	$362.0 - $460.6	$413.4

Note: Base amounts definitive only for the Preliminary Preferred Route scenarios. Base amounts represent the Applicant's low end cost estimate, plus an amount to reflect the Applicant's risk analysis.

Development and Construction Cost Proposal

As discussed above, the Applicant's development and construction cost estimates for the EWTL pursuant to the Preferred Design and the Reference Design over the Preliminary Preferred Route are definitive. Accordingly the Applicant proposes a Bid Amount for the development and construction of the EWTL over the Preliminary Preferred Route of $413.4 million for the Preferred Design and $493.7 million for the Reference Design, in each case subject to escalation. With respect to the Bid Amounts, the Applicant proposes to be bound by a unique and innovative risk-sharing mechanism:

1. an incentive rate methodology that rewards RES Transmission for completing the development and construction of the Project for less than its Bid Amount and penalizes RES Transmission for exceeding the Bid Amount, as follows:

    - **costs underages:** for each year that the EWTL is in service, the value of its Board-approved rate base would be reduced by the amount of any cost underages (the "**Subtracted Amount**"). Sixty percent of the remainder would earn a return at the Board's deemed cost of long-term debt, determined annually, and 40 percent of the remainder would earn a return at the return on equity determined by the Board, annually ("**ROE**"). Forty percent of the Subtracted Amount would earn an incentive return equal to the sum of the ROE and 300 basis points. Sixty percent of the Subtracted Amount would earn a return at the Board's deemed cost of long-term debt, determined annually;

- **cost overages:** for each year that the EWTL is in service, the ROE that would otherwise be earned on 40 percent of any prudently incurred cost overages would be reduced and RES Transmission would instead earn only the deemed cost of long-term debt, as determined by the OEB annually, on 100 percent of such overages; and

- **exceptions:** The equity portion (i.e., 40%) of the difference between the actual costs incurred in four cost categories over which the Applicant has little or no control and the estimates of such costs that are embedded in the Bid Amounts in the four categories, up to a specified limit , would earn a return at the ROE determined by the Board, annually, and would not be subject to the penalty that would be otherwise applicable to cost overages under the Applicant's proposed incentive rate methodology. The four categories are as follows: land acquisition (up to $15.5 million); First Nation and Métis participation costs and accommodation (up to $1.0 million); environmental and permitting costs (up to $2.5 million); and line costs in respect of a total line length that exceeds 410 km ($1 million for each additional km);

2. the utilization of US GAAP for regulatory accounting, reporting and rate-making purposes; and

3. the calculation of interest for CWIP at a blended rate as discussed in Exhibit B-1-1.

This Development and Construction Cost Proposal is discussed further in Exhibits P-5-1 and P-7-1.

Application of the Development and Construction Cost Proposal to Other Scenarios

The Applicant is willing and is able to apply its Development and Construction Cost Proposal to the two other potential development scenarios for the EWTL involving the Reference Route, but at this time, the Applicant's cost estimates are not sufficiently definitive to establish a Bid Amount for each such scenario. Such costs could be defined subsequent to designation, for submission in an application for LTC for the EWTL, if desired by the Board and the Applicant was to construct the EWTL pursuant to one of the two other development and construction scenarios.

Cost Savings

As confirmation of the benefits to the ratepayers of the Board's competitive process, the Applicant's $413.4 million Bid Amount for the Preferred Design over the Preliminary Preferred Route is materially less than the amounts budgeted by Hydro One in its 2010 submission to the Board which ranged from $528 million to $636 million for the line components of the Project for single circuit and double circuit designs, respectively.[1] Also, the Applicant's Bid Amount for this option is substantially less than the $480 million targeted by the OPA for the line components of the Project.[2]

---

[1] Hydro One's Project Definition Report, June 4, 2010: AR18379 Project Definition Report, Study Estimates for Options, East-West Tie Expansion

[2] Response from OPA to question submitted to OEB on February 29, 2012 and posted on OEB's project website and in OEB's 2012 stakeholder meetings

Operating and Maintenance Costs

With regard to O&M costs for the Project for its greater than 50 year life, the Applicant has used the extensive experience of the RES Group and the MidAmerican Group and estimated annual O&M costs of $2.2 million per annum, exclusive of certain annual or periodically recurring expenses identified in Exhibit P-6-1, including payments made to First Nation and Métis. O&M and other annual costs for the Project will be estimated in more detail following designation and are discussed further in Exhibit P-6.

Reimbursement of Development Costs

In the event that the Board designates the Applicant, the reimbursement of development costs would occur during the normal course of a rate application, after the Project is placed in service. However, in the event that the Project is not constructed, the Applicant would seek reimbursement of and a return on its development costs and reasonable wind-up costs consistent with this Application and the Phase 1 Decision, subject to the limits imposed by Applicant (i.e., capping project management costs and associated expenses at $4.3 million and no cost recovery for its $1.5 million pre-designation costs).

Risk Assessments

The Applicant has made detailed risk assessments for Project schedules and costs as requested in the Phase 1 Decision (Exhibit P-5-1). However, the vast majority of those risks are borne by the Applicant in its Development and Construction Cost Proposal as the Applicant has established incentives to minimize the impacts of risks on ratepayers, with the exception of the four Exceptions over which Applicant has little or no control of costs.

The Applicant's innovative cost proposal has been structured to transfer in large part the risk of deviations from the Applicant's Project cost estimates, if any, to the Applicant to the clear advantage of rate payers. This is discussed in further detail in Exhibit P-5-1.

Phased Installation

While the Applicant's proposal is focused on the cost of the line component of the Project, it has also assessed the advantages to ratepayers of a phased installation of substation upgrades that are the cost responsibility of Hydro One, which its Preferred Design, as compared to the Reference Design, uniquely permits. Sequential and staged substation upgrades can be implemented over time to achieve incremental increases in line transfers ranging from 387 MW to 684 MW[3], when and if, such transfer capacities and associated upgrades are needed. The avoided cost or deferred cost of these upgrades and the aggregate savings are discussed further in Exhibit P-4-3.

---

[3] IESO Feasibility Study, December 29, 2012

TAB P-2-1

Designations Costs

The Applicant has incurred approximately $1.2 million in Designation Costs since February 2, 2012 – the date established in the Phase 1 Decision as the date after which the designated transmitter's Designation Costs are eligible for reimbursement. The Applicant anticipates incurring an additional $0.3 million in such Designation Costs to participate in the designation proceedings subsequent to the date of the submission of this Application and the selection of the designated transmitter. Such costs include Applicant's internal time charges, travel-related costs, and the retention of consultants and advisors.

Designation Costs can be grouped into three major categories, as follows:

- Application preparation costs;
- participation in designation proceedings;
- early development studies to expedite the Project's in-service date in the event of Applicant's designation, particularly for routing and construction access.

The Applicant will not seek reimbursement for these approximate $1.5 million in Designation Costs it has incurred and will incur prior to designation.

TAB P-3-1

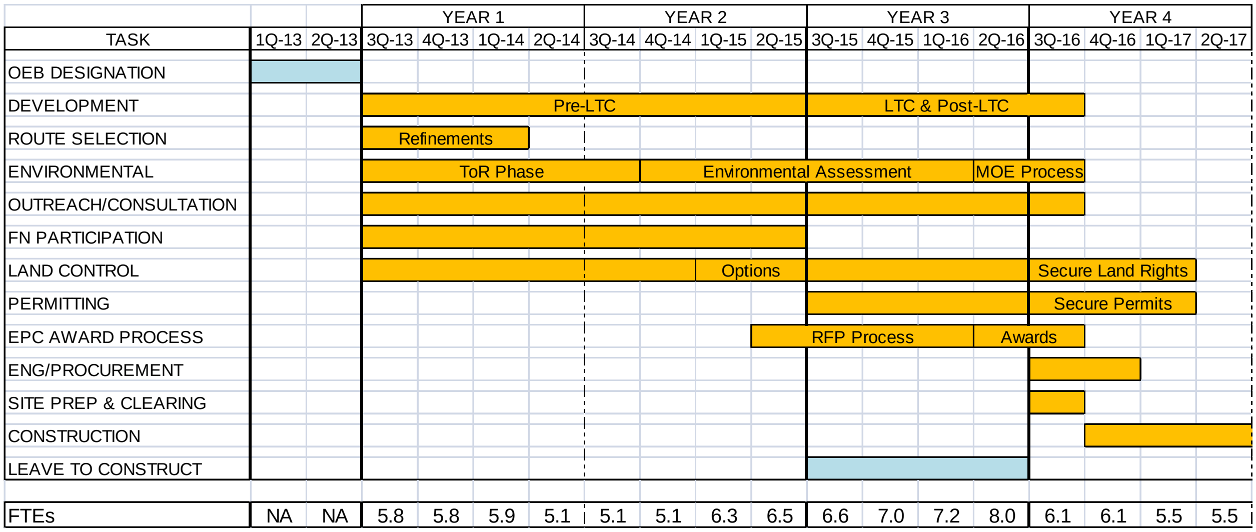
Development Phase - Overview

As defined by the Board, the Development Phase for the Project commences upon designation and concludes with the submission of an application for LTC of the EWTL. Mindful of the need to expedite the COD of the EWTL, the Applicant anticipates completion of the Development Phase two years following designation, during which time sufficient information would be available to permit the submission of a complete application for LTC for the EWTL. Key elements of this plan to complete the development phase in two years include:

- completing the selection of a preferred route;
- the completion of the ToR process with the MOE;
- substantial progress in the EA and consultation tasks;
- the completion of substantial engineering and cost estimating activities;
- collaboration with OPA on a needs assessment;
- securing option agreements for land rights;
- initiating the process to competitively bid an EPC contractor; and
- negotiating First Nation and Métis participation agreements and IBAs.

The schedule for these activities is addressed in Exhibit N and summarized in Table P-4 below.

Table P-4: Schedule



			YEAR 1				YEAR 2				YEAR 3				YEAR 4			
TASK	1Q-13	2Q-13	3Q-13	4Q-13	1Q-14	2Q-14	3Q-14	4Q-14	1Q-15	2Q-15	3Q-15	4Q-15	1Q-16	2Q-16	3Q-16	4Q-16	1Q-17	2Q-17
OEB DESIGNATION	🟦	🟦																
DEVELOPMENT			Pre-LTC	🟨	🟨	🟨	🟨	🟨	🟨	🟨	LTC & Post-LTC	🟨	🟨	🟨	🟨			
ROUTE SELECTION			Refinements	🟨	🟨													
ENVIRONMENTAL			ToR Phase	🟨	🟨	🟨	🟨	Environmental Assessment	🟨	🟨	🟨	🟨	🟨	MOE Process	🟨			
OUTREACH/CONSULTATION			🟨	🟨	🟨	🟨	🟨	🟨	🟨	🟨	🟨	🟨	🟨	🟨	🟨			
FN PARTICIPATION			🟨	🟨	🟨	🟨	🟨	🟨	🟨	🟨								
LAND CONTROL			🟨	🟨	🟨	🟨	🟨	🟨	Options	🟨	🟨	🟨	🟨	🟨	Secure Land Rights	🟨	🟨	
PERMITTING											🟨	🟨	🟨	🟨	Secure Permits	🟨	🟨	
EPC AWARD PROCESS										RFP Process	🟨	🟨	🟨	Awards	🟨			
ENG/PROCUREMENT															🟨	🟨		
SITE PREP & CLEARING															🟨			
CONSTRUCTION																🟨	🟨	🟨
LEAVE TO CONSTRUCT											🟦	🟦	🟦	🟦				
FTEs	NA	NA	5.8	5.8	5.9	5.1	5.1	5.1	6.3	6.5	6.6	7.0	7.2	8.0	6.1	6.1	5.5	5.5

This approach is intended to minimize development costs until assurance is gained via a successful LTC determination from the Board that the Project will be constructed. For instance, the substantial costs of acquiring land rights and implementing First Nation and Metis participation agreements and IBAs can be delayed until the completion of a successful LTC hearing, rather than being incurred during the development phase of the Project.

On the basis of the assumptions above and:

- the completion of an extensive segment by segment field and desktop analysis of available information, spending more than 50 person-days in the field for the purposes of inspecting, gathering data and assessing the Reference Route and the Preliminary Preferred Route and their associated construction and access options;

- reports compiled internally by the Applicant and Stantec with respect to costs for environmental, land routing, consultation and First Nation and Métis development activities;

- the accumulated experience of the RES Group and the MidAmerican Group based on costs of recently built projects and build-up estimating methods and models as discussed in Exhibit P-1-1 and Exhibit E; and

- a detailed risk analysis as set out in Exhibit P-5-1,

the Applicant's estimate of costs for the Development Phase of the Project ranges from $20.1 million to $22.9 million, with a bid amount cost of $21.5 million (see below) for which the Applicant seeks the Board's approval as reasonable for future recovery in rates. The largest line item in the development budget is engineering design which will involve a combination of internal resources and the competitive selection and retention of an Owners' Engineer. Project management and related expenses will constitute approximately 20 percent of the budget at $4.3 million, with estimated FTEs shown on the final row of Table P-4 above. The Applicant proposes that its internal project management costs and expenses are capped at $4.3 million.

Land control costs are budgeted at $2.4 million, with an additional $13.1 million to be incurred during the construction phase, subsequent to the completion of a successful LTC hearing.

It is confirmed that the Project development costs set out in Table P-5 are applicable to each of the four potential configuration scenarios for the EWTL involving the Preferred Design, Reference Design, Preliminary Preferred Route or Reference Route.

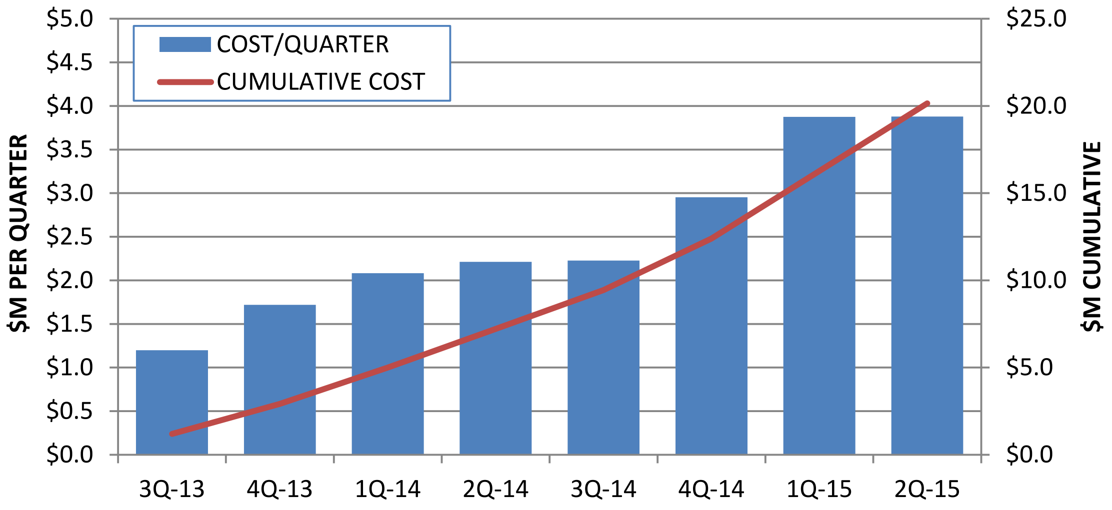
Table P-5

PROJECT DEVELOPMENT COSTS (millions, $2013)			
CATEGORY	LOW	BID COST	HIGH
Engineering & Design	$9.60	$9.60	$9.60
Project Management & Expenses	$4.30	$4.30	$4.30
Land Control	$2.40	$2.40	$2.40
Consultation & FN Participation	$2.20	$2.20	$2.20
Environmental/Permitting	$1.60	$1.60	$1.60
Contingencies/Risks	$0.00	$1.40	$2.80
TOTALS	$20.10	$21.50	$22.90

These cost estimates are subject to escalation in accordance with CPI All-items Consumer Price Index commencing in February 2013 to the date the application for LTC of the EWTL is filed.

The schedule for development expenditures, exclusive of contingency and risk costs is summarized below in Figure P-1 and detailed in Exhibit P-3-2. It illustrates the gradual ramping up of activities during the Development Phase, culminating in the collaboration on a needs assessment with OPA and the preparation of an application for LTC of the EWTL in the final two quarters of the Development Phase.

Figure P-1



($2013, millions)

	3Q-13	4Q-13	1Q-14	2Q-14	3Q-14	4Q-14	1Q-15	2Q-15
COST/QUARTER	$1.2	$1.7	$2.1	$2.2	$2.2	$3.0	$3.9	$3.9
CUMULATIVE COST	$1.2	$2.9	$5.0	$7.2	$9.4	$12.4	$16.3	$20.2

TAB P-3-2

Development Phase – Budget & Underpinning Assumptions

Item Description		Development Phase							
		2013		2014				2015	
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Major Contracts									
Planning Studies & Cost Benefit Analysis	$ 550,000	$ 125,000	$ 250,000	$ 125,000			$ 20,000	$ 20,000	$ 10,000
Owners Engineer (Pre-Construction)	$ 9,036,804			$ 430,324	$ 860,648	$ 860,648.02	$ 1,721,296	$ 2,581,944	$ 2,581,944
Route Selection Services	$ 82,500	$ 41,250	$ 41,250	$ -	$ -	$ -	$ -	$ -	$ -
Environmental Assessment	$ 1,479,359	$ 142,246	$ 142,246	$ 189,661	$ 189,661	$ 208,628	$ 208,628	$ 208,628	$ 189,661
Stakeholder Outreach	$ 463,135	$ 40,865	$ 40,865	$ 68,108	$ 68,108	$ 68,108	$ 68,108	$ 54,487	$ 54,487
Aboriginal Consultation	$ 91,039	$ 9,842	$ 12,303	$ 12,303	$ 12,303	$ 12,303	$ 12,303	$ 9,842	$ 9,842
Aboriginal Consultation (Legal)	$ 200,000	$ 50,000	$ 50,000	$ -	$ -	$ -	$ -	$ -	$ 100,000
Internal (MAT/RES)									
Executive Management	$ 360,360	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045
Project Management	$ 2,893,363	$ 326,726	$ 331,094	$ 335,462	$ 352,934	$ 357,302	$ 357,302	$ 407,971	$ 424,570
Engineering Management	$ 450,450	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 90,090	$ 90,090
Transmission/Planning	$ 245,700	$ 81,900	$ 81,900	$ 81,900	$ -	$ -	$ -	$ -	$ -
Expenses	$ 357,494	$ 44,936	$ 45,154	$ 45,373	$ 42,151	$ 42,370	$ 42,370	$ 47,155	$ 47,985
Miscellaneous Costs									
Legal Fees	$ 300,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 50,000	$ 100,000
Media Relations/Community	$ 400,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
ROW Costs									
Right-of-Way Labor & Legal	$ 1,753,300	$ 95,813	$ 250,013	$ 320,013	$ 325,013	$ 315,013	$ 197,813	$ 149,813	$ 99,813
ROW/Easements	$ 723,000	$ 30,000	$ 135,000	$ 135,000	$ 102,000	$ 102,000	$ 75,000	$ 75,000	$ 69,000
First Nations	$ 764,000	$ 46,000	$ 175,000	$ 175,000	$ 95,000	$ 95,000	$ 86,000	$ 86,000	$ 6,000
SUBTOTAL PROJECT COSTS		**$ 1,199,668**	**$ 1,719,915**	**$ 2,083,234**	**$ 2,212,908**	**$ 2,226,461**	**$ 2,953,909**	**$ 3,875,974**	**$ 3,878,436**
TOTAL DEVELOPMENT COST	**$ 20,150,504**								

ASSUMPTIONS/BASIS/CLARIFICATIONS

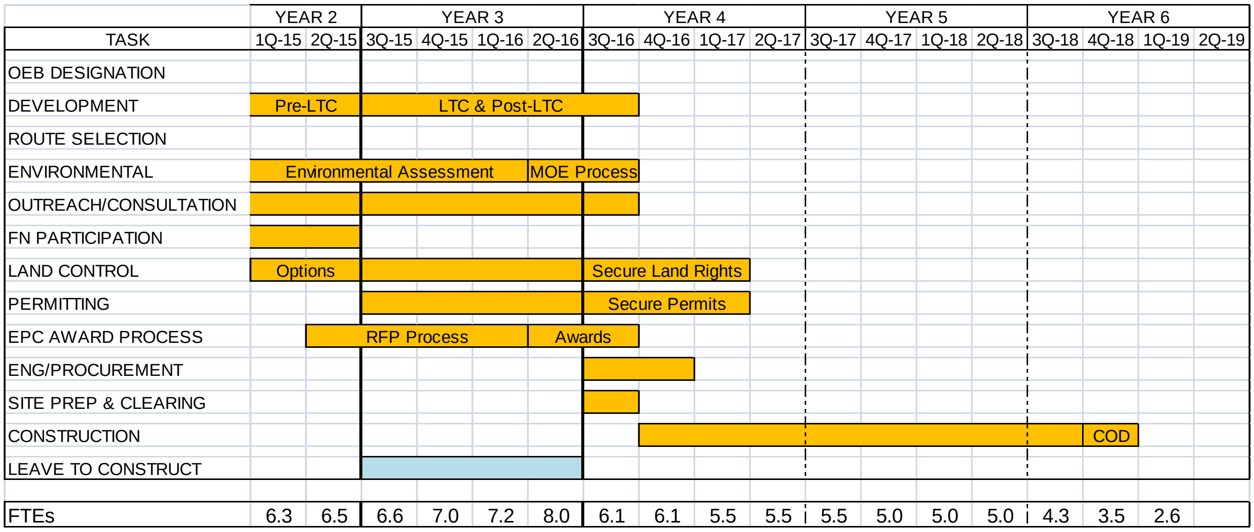
Development Phase ends with LTC filing. Project development will continue through LTC period.
Assumes 30-40% design complete at the end of the development phase ready for a bid for final design & construct.
EA cost estimate from Stantec assumes only 25% of the line route will require detail field survey for EA purposes.
Assumes HST tax is not applicable to the Project.
Assumes no agency cost recovery agreements are required for EA process.
Construction cost models listed as Average, are averages of extroploted and BUE values.
Excludes Contingency Risk items (unless expressly identified).
Excludes CWIP (unless expressly identified).
Excludes Surcharge.

TAB P-4-1

Construction Phase – Overview

The Construction Phase for the EWTL, for the purposes of this Application, is defined to immediately follow the Development Phase and concludes with the COD for the EWTL. The construction phase includes the LTC hearing for the EWTL and the final stages of the Project's development as well as the construction of the Project. The schedule of activities included in the Construction Phase (and the final two quarters of development activities) is illustrated in Table P-6 below, along with the FTEs for project management activities.

Table P-6



	YEAR 2		YEAR 3				YEAR 4				YEAR 5				YEAR 6			
TASK	1Q-15	2Q-15	3Q-15	4Q-15	1Q-16	2Q-16	3Q-16	4Q-16	1Q-17	2Q-17	3Q-17	4Q-17	1Q-18	2Q-18	3Q-18	4Q-18	1Q-19	2Q-19
OEB DESIGNATION																		
DEVELOPMENT	Pre-LTC	▨	LTC & Post-LTC	▨	▨	▨	▨											
ROUTE SELECTION																		
ENVIRONMENTAL	Environmental Assessment	▨	▨	▨	▨	MOE Process	▨											
OUTREACH/CONSULTATION	▨	▨	▨	▨	▨	▨	▨											
FN PARTICIPATION	▨	▨																
LAND CONTROL	Options	▨	▨	▨	▨	▨	Secure Land Rights	▨										
PERMITTING			▨	▨	▨	▨	Secure Permits	▨										
EPC AWARD PROCESS		RFP Process	▨	▨	▨	Awards	▨											
ENG/PROCUREMENT							▨	▨										
SITE PREP & CLEARING							▨											
CONSTRUCTION								▨	▨	▨	▨	▨	▨	▨	▨	COD		
LEAVE TO CONSTRUCT			░	░	░	░												
FTEs	6.3	6.5	6.6	7.0	7.2	8.0	6.1	6.1	5.5	5.5	5.5	5.0	5.0	5.0	4.3	3.5	2.6	

As shown, the Applicant contemplates that the Construction Phase would commence two years after designation in mid-2015, following the submission of the Applicant's application for LTC for the EWTL. The Applicant has budgeted for a year-long LTC hearing in which significant work initiated during the Development Phase is continued, particularly:

- the EA, outreach and consultation efforts;

- the securing of land rights; and
- a competitive EPC contractor selection and award process.

Permitting activities would be initiated during the course of the LTC hearings. Upon successful completion of LTC hearings, the Applicant would move to exercise options for land control, implement First Nation and Métis Participation Agreements, secure permits, award EPC contracts, and initiate engineering, procurement, and site preparation/clearing efforts with a goal of starting construction in late 2016. Any delays in the LTC hearings that extend beyond one year that has been budgeted would result in a corresponding delay in these foregoing efforts and in the Project's COD.

The breakdown of costs for the Construction Phase for Applicant's preferred scenario for the EWTL, being the Preferred Design over the Preliminary Preferred Route is summarized in Table P-7 below for the low, base, and high cost estimates, including contingencies and risks for a year-end 2018 COD.

Table P-7

PROJECT CONSTRUCTION COSTS ($2013, millions)			
CATEGORY	LOW	BASE	HIGH
Materials & Supplies	$187.6	$187.6	$187.6
EPC Contractor	$80.4	$80.4	$80.4
Land Control	$13.0	$13.0	$13.0
Engineering & Design	$12.8	$12.8	$12.8
Man Camps & Misc	$12.6	$12.6	$12.6
Site Preparation/Clearing	$11.3	$11.3	$11.3
Construction Inspection/Management	$8.1	$8.1	$8.1
Project Management & Expenses	$7.7	$7.7	$7.7
Environmental/Permitting	$6.2	$6.2	$6.2
Consultation & FN Participation	$2.0	$2.0	$2.0
Contingencies/Risks	$0.0	$50.2	$96.0
TOTALS	$341.7	$391.9	$437.7

With respect to the other three scenarios, the aggregate costs to be incurred during the Construction Phase of the EWTL will, for the:

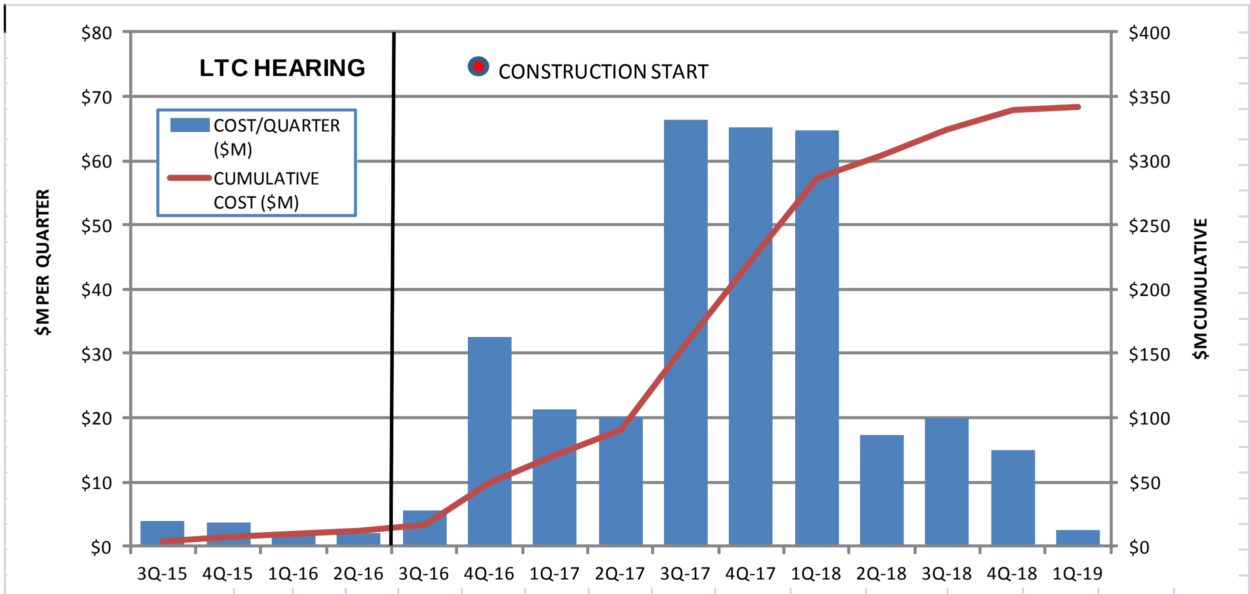
- Reference Design over the Preliminary Preferred Route, be within the range of $422.6 million to $518.8 million, with a base amount of $472.2 million;

- Preferred Design over the Reference Route, be within the range of $340.8 million to $436.6 million, with a base amount of $400.4 million;

- Reference Design over the Reference Route, be within the range of $417.1 million to $512.9 million, with a base amount of $476.7 million.

For the Preferred Design over the Preliminary Preferred Route scenario, a schedule of expenditures, based on the low estimate case and exclusive of contingency and risk costs**,** is presented in Figure P-2 below for the LTC and subsequent portions of the Construction Phase for a year-end 2018 COD. As shown, $11.5 million of expenditures are scheduled for the LTC hearing stage, with substantial expenditures within six months of a successful determination from the Board on LTC in which land rights would be acquired, site preparation and clearing activities conducted, and First Nation and Métis participation agreements and IBAs implemented. The majority of construction expenditures are scheduled for the second half of 2017 and the first quarter of 2018.

Figure P-2



	3Q-15	4Q-15	1Q-16	2Q-16	3Q-16	4Q-16	1Q-17	2Q-17	3Q-17	4Q-17	1Q-18	2Q-18	3Q-18	4Q-18	1Q-19
COST/QUARTER ($M)	$3.8	$3.8	$1.9	$2.0	$5.5	$32.6	$21.3	$20.1	$66.4	$65.2	$64.6	$17.2	$19.8	$14.9	$2.6
CUMULATIVE COST ($M)	$3.8	$7.6	$9.5	$11.5	$17.0	$49.6	$70.9	$91.0	$157.4	$222.6	$287.2	$304.4	$324.2	$339.1	$341.7

Detailed spreadsheets of estimated Project costs and assumptions, based on the low estimate case and exclusive of contingencies and risks, for each of the Applicant's four scenarios are included in Exhibit P-4-2.

TAB P-4-2

Construction Phase – Budget & Underpinning Assumptions

The Applicant has used:

- the completion of an extensive segment by segment field analysis and desktop analysis of available information, spending more than 50 person-days in the field for the purpose of inspecting, gathering data and assessing the Reference Route and the Preliminary Preferred Route and their associated construction and access options;
- extrapolation on costs of recently built projects and build-up estimating methods and models to arrive at the construction budget portion of each cost estimate;
- the results of the accumulated experience of the RES Group and the MidAmerican Group as discussed in Exhibit P-1-1 and Exhibit E;
- studies and analysis compiled internally by the Applicant and Stantec to date with respect to costs for environmental, land routing, consultation and First Nation and Métis development activities; and
- the detailed risk analysis, details of which are set out in Exhibit P-5-1,

to prepare the cost estimate spreadsheets shown in this Exhibit P-4-2. These spreadsheets are exclusive of contingency and risk costs which were added separately to establish final estimates and bid amounts. Each cost estimate proposed is based on the following assumptions:

- Applicant designation by June 2013, filing of an LTC application by June 2015, with LTC granted by the Board by June 2016 and COD by the end of 2018;
- all figures are in 2013 values and therefore subject to escalation for inflation in accordance with EUCPI Table #327-0011 commencing in January 2013 and ending with the COD of the EWTL;

- excludes Hydro One costs of interconnections and substation upgrades;
- the Applicant is able to make substantial progress on environmental assessment, engineering design and permitting, consultation, and the negotiation of land agreements and First Nation and Métis participation agreements and IBAs within 24 months from the date of designation; and
- the Applicant obtains all necessary support and co-operation from all the agencies that are responsible for completing various aspects of the development work.

The Applicant estimates that placing the EWTL in-service in 2017 would approximately increase Project cost by 20 percent to 30 percent. If the Board requests that the Applicant revises its proposed COD for the EWTL to a date in 2017, the Applicant would at such time be willing to revise its Project cost estimates, provide definitive cost estimates to reflect a COD in 2017 and at the same time reconsider the applicability of the Development and Construction Cost Proposal.

Mid American Transmission/RES Canada
Ontario Energy Board
Cost Model Bid Proposal
12/20/2012

Preferred Design - Preliminary Preferred Route

Cost Model Type	AVG
230kV Single ALT H Frame	A

Item Description		**Development Phase**								**Construction: LTC Review Period**				**Construction: Delivery Phase**										**Close out**
		2013		**2014**				**2015**				**2016**				**2017**				**2018**				**2019**
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
Major Contracts																								
Transmission Line Construction/Engineering/Management	$ 80,415,922														$ 4,467,551	$ 4,467,551	$ 4,467,551	$ 17,870,205	$ 17,870,205	$ 17,870,205	$ 4,467,551	$ 4,467,551	$ 2,233,776	$ 2,233,776
Transmission Line Materials/Equipment	$ 187,637,152														$ 10,424,286	$ 10,424,286	$ 10,424,286	$ 41,697,145	$ 41,697,145	$ 41,697,145	$ 10,424,286	$ 10,424,286	$ 10,424,286	
Planning Studies & Cost Benefit Analysis	$ 550,000	$ 125,000	$ 250,000	$ 125,000			$ 20,000	$ 20,000	$ 10,000															
Owners Engineer (Pre-Construction)	$ 17,212,960			$ 430,324	$ 860,648	$ 860,648	$ 1,721,296	$ 2,581,944	$ 2,581,944	$ 2,581,944	$ 2,581,944	$ 860,648	$ 860,648	$ 860,648	$ 430,324									
Owner Engineer (Construction Phase)	$ 4,664,688														$ 466,469	$ 699,703	$ 699,703	$ 699,703	$ 699,703	$ 699,703	$ 233,234	$ 233,234	$ 116,617	$ 116,617
Route Selection Services	$ 82,500	$ 41,250	$ 41,250	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -									
Environmental Assessment	$ 1,896,614	$ 142,246	$ 142,246	$ 189,661	$ 189,661	$ 208,628	$ 208,628	$ 208,628	$ 189,661	$ 208,628	$ 189,661	$ 18,966	$ -	$ -										
Stakeholder Outreach	$ 544,865	$ 40,865	$ 40,865	$ 68,108	$ 68,108	$ 68,108	$ 68,108	$ 54,487	$ 54,487	$ 54,487	$ 27,243	$ -	$ -	$ -										
Aboriginal Consultation	$ 98,420	$ 9,842	$ 12,303	$ 12,303	$ 12,303	$ 12,303	$ 12,303	$ 9,842	$ 9,842	$ 4,921	$ 2,461	$ -	$ -											
Aboriginal Consultation (Legal)	$ 250,000	$ 50,000	$ 50,000	$ -	$ -	$ -	$ -	$ -	$ 100,000	$ 50,000	$ -	$ -	$ -	$ -										
Non EA permitting	$ 468,724	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,181	$ 117,181	$ 117,181	$ 117,181	$ -	$ -									
Construction Inspection/Management	$ 8,143,438														$ 452,413	$ 452,413	$ 452,413	$ 1,809,653	$ 1,809,653	$ 1,809,653	$ 452,413	$ 452,413	$ 452,413	
Enviromental Inspection Contractor	$ 5,281,375														$ 293,410	$ 293,410	$ 293,410	$ 1,173,639	$ 1,173,639	$ 1,173,639	$ 293,410	$ 293,410	$ 293,410	
Vegetation Management	$ 11,270,000														$ 3,381,000	$ 3,381,000	$ 2,254,000	$ 1,690,500	$ 563,500					
Install & Maintain Man Camps	$ 9,933,732														$ 2,980,119	$ 851,463	$ 851,463	$ 851,463	$ 851,463	$ 851,463	$ 851,463	$ 851,463	$ 993,373.2	
Spare Parts Facility	$ 1,000,000																					$ 775,000		
Capitalized Spare Parts	$ 1,876,372																					$ 1,876,372		
Internal (MAT/RES)																								
Executive Management	$ 738,738	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 63,063	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ -
Project Management	$ 8,869,661	$ 326,726	$ 331,094	$ 335,462	$ 352,934	$ 357,302	$ 357,302	$ 407,971	$ 424,570	$ 435,926	$ 467,376	$ 489,216	$ 543,379	$ 414,960	$ 414,960	$ 414,960	$ 414,960	$ 414,960	$ 393,120	$ 393,120	$ 393,120	$ 327,600	$ 262,080	$ 196,560
Engineering Management	$ 1,273,545	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 45,045	$ 45,045	$ 45,045	$ 24,570	$ 24,570	$ 24,570	$ 24,570	$ 24,570	$ 24,570
Transmission/Planning	$ 245,700	$ 81,900	$ 81,900	$ 81,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Expenses	$ 836,382	$ 44,936	$ 45,154	$ 45,373	$ 42,151	$ 42,370	$ 42,370	$ 47,155	$ 47,985	$ 48,553	$ 50,126	$ 51,218	$ 54,827	$ 46,153	$ 46,153	$ 23,901	$ 23,901	$ 23,901	$ 21,785	$ 21,785	$ 21,785	$ 18,509	$ 15,233	$ 11,057
Material Procurement (included in construction contracts)																								
Miscellaneous Costs																								
Legal Fees	$ 1,500,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 50,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 200,000	$ 175,000	$ 150,000	$ 125,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	
Media Relations/Community	$ 1,000,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	
ROW Costs																								
Right-of-Way Labor & Legal	$ 3,257,560	$ 95,813	$ 250,013	$ 320,013	$ 325,013	$ 315,013	$ 197,813	$ 149,813	$ 99,813	$ 47,000	$ 47,000	$ 47,000	$ 107,000	$ 371,862	$ 884,398									
ROW/Easements	$ 12,221,264	$ 30,000	$ 135,000	$ 135,000	$ 102,000	$ 102,000	$ 75,000	$ 75,000	$ 69,000	$ -	$ -	$ -	$ -	$ 3,444,307	$ 8,053,957									
First Nations	$ 800,000	$ 46,000	$ 175,000	$ 175,000	$ 95,000	$ 95,000	$ 86,000	$ 86,000	$ 6,000	6000	6000	$ 6,000	$ 6,000	$ 6,000	$ 6,000									
AFUDC																								
SUBTOTAL PROJECT COSTS		**$ 1,199,668**	**$ 1,719,915**	**$ 2,083,234**	**$ 2,212,908**	**$ 2,226,461**	**$ 2,953,909**	**$ 3,875,974**	**$ 3,878,436**	**$ 3,839,775**	**$ 3,774,127**	**$ 1,875,364**	**$ 1,992,188**	**$ 5,502,039**	**$ 32,634,149**	**$ 21,271,750**	**$ 20,119,750**	**$ 66,369,232**	**$ 65,197,801**	**$ 64,609,301**	**$ 17,229,851**	**$ 19,812,426**	**$ 14,883,777**	**$ 2,582,579**
Contingency/Risk	$ -								$ -															$ -
OVERALL PROJECT VALUE	$ 362,069,611								$ 20,150,504															$ 341,694,107

ASSUMPTIONS/BASIS/CLARIFICATIONS

Development Phase ends with LTC filing. Project development will continue through LTC period.
Assumes 30-40% design complete at the end of the development phase ready for a bid for final design & construct.
EA cost estimate from Stantec assumes only 25% of the line route will require detail field survey for EA purposes.
Assumes that HST tax is not applicable to the Project.
Assumes that no agency cost recovery agreements are required for EA process.
Construction cost models listed as average, are averages of extroploted and BUE values.
See individual tabs for item estimate basis.
Where cashflow is not itemized then costs are distributed on a 1/3rds 2/3rds basis. THIS IS NOT BASED ON A RESOURCE LOADED SCHEDULE
Excludes Contingency Risk items (unless expressly identified).
Excludes CWIP (unless expressly identified).
Excludes Surcharge.

Mid American Transmission/RES Canada
Ontario Energy Board
Cost Model Bid Proposal
12/20/2012

Preferred Design - Reference Route

Cost Model Type	AVG
230kV Single BASE H Frame	D

Item Description		**Development Phase**								**Construction: LTC Review Period**				**Construction: Delivery Phase**												**Close out**
		2013		2014				2015				2016				2017				2018				2019
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
Major Contracts																								
Transmission Line Construction/Engineering/Management	$ 79,542,928														$ 4,419,052	$ 4,419,052	$ 4,419,052	$ 17,676,206	$ 17,676,206	$ 17,676,206	$ 4,419,052	$ 4,419,052	$ 2,209,526	$ 2,209,526
Transmission Line Materials/Equipment	$ 185,600,165														$ 10,311,120	$ 10,311,120	$ 10,311,120	$ 41,244,481	$ 41,244,481	$ 41,244,481	$ 10,311,120	$ 10,311,120	$ 10,311,120	
Planning Studies & Cost Benefit Analysis	$ 550,000	$ 125,000	$ 250,000	$ 125,000			$ 20,000	$ 20,000	$ 10,000															
Owners Engineer (Pre-Construction)	$ 16,872,783			$ 421,820	$ 843,639	$ 843,639	$ 1,687,278	$ 2,530,918	$ 2,530,918	$ 2,530,918	$ 2,530,918	$ 843,639	$ 843,639	$ 843,639	$ 421,820									
Owner Engineer (Construction Phase)	$ 4,572,500														$ 457,250	$ 685,875	$ 685,875	$ 685,875	$ 685,875	$ 685,875	$ 228,625	$ 228,625	$ 114,313	$ 114,313
Route Selection Services	$ 82,500	$ 41,250	$ 41,250	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -									
Environmental Assessment	$ 1,896,614	$ 142,246	$ 142,246	$ 189,661	$ 189,661	$ 208,628	$ 208,628	$ 208,628	$ 189,661	$ 208,628	$ 189,661	$ 18,966	$ -	$ -										
Stakeholder Outreach	$ 544,865	$ 40,865	$ 40,865	$ 68,108	$ 68,108	$ 68,108	$ 68,108	$ 54,487	$ 54,487	$ 54,487	$ 27,243	$ -	$ -	$ -										
Aboriginal Consultation	$ 98,420	$ 9,842	$ 12,303	$ 12,303	$ 12,303	$ 12,303	$ 12,303	$ 9,842	$ 9,842	$ 4,921	$ 2,461	$ -	$ -											
Aboriginal Consultation (Legal)	$ 250,000	$ 50,000	$ 50,000	$ -	$ -	$ -	$ -	$ -	$ 100,000	$ 50,000	$ -	$ -	$ -	$ -										
Non EA permitting	$ 468,724	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,181	$ 117,181	$ 117,181	$ 117,181	$ -	$ -									
Construction Inspection/Management	$ 7,982,500														$ 443,472	$ 443,472	$ 443,472	$ 1,773,889	$ 1,773,889	$ 1,773,889	$ 443,472	$ 443,472	$ 443,472	
Enviromental Inspection Contractor	$ 5,177,000														$ 287,611	$ 287,611	$ 287,611	$ 1,150,444	$ 1,150,444	$ 1,150,444	$ 287,611	$ 287,611	$ 287,611	
Vegetation Management	$ 11,047,273														$ 3,314,182	$ 3,314,182	$ 2,209,455	$ 1,657,091	$ 552,364					
Install & Maintain Man Camps	$ 12,633,060														$ 3,789,918	$ 1,082,834	$ 1,082,834	$ 1,082,834	$ 1,082,834	$ 1,082,834	$ 1,082,834	$ 1,082,834	$ 1,263,306.0	
Spare Parts Facility	$ 1,000,000																					$ 775,000		
Capitalized Spare Parts	$ 1,856,002																					$ 1,856,002		
Internal (MAT/RES)																								
Executive Management	$ 738,738	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 63,063	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ -
Project Management	$ 8,869,661	$ 326,726	$ 331,094	$ 335,462	$ 352,934	$ 357,302	$ 357,302	$ 407,971	$ 424,570	$ 435,926	$ 467,376	$ 489,216	$ 543,379	$ 414,960	$ 414,960	$ 414,960	$ 414,960	$ 414,960	$ 393,120	$ 393,120	$ 393,120	$ 327,600	$ 262,080	$ 196,560
Engineering Management	$ 1,273,545	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 45,045	$ 45,045	$ 45,045	$ 24,570	$ 24,570	$ 24,570	$ 24,570	$ 24,570	$ 24,570
Transmission/Planning	$ 245,700	$ 81,900	$ 81,900	$ 81,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Expenses	$ 836,382	$ 44,936	$ 45,154	$ 45,373	$ 42,151	$ 42,370	$ 42,370	$ 47,155	$ 47,985	$ 48,553	$ 50,126	$ 51,218	$ 54,827	$ 46,153	$ 46,153	$ 23,901	$ 23,901	$ 23,901	$ 21,785	$ 21,785	$ 21,785	$ 18,509	$ 15,233	$ 11,057
Material Procurement (included in construction contracts)																								
Miscellaneous Costs																								
Legal Fees	$ 1,500,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 50,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 200,000	$ 175,000	$ 150,000	$ 125,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	
Media Relations/Community	$ 1,000,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	
ROW Costs																								
Right-of-Way Labor & Legal	$ 3,257,560	$ 95,813	$ 250,013	$ 320,013	$ 325,013	$ 315,013	$ 197,813	$ 149,813	$ 99,813	$ 47,000	$ 47,000	$ 47,000	$ 107,000	$ 371,862	$ 884,398									
ROW/Easements	$ 12,221,264	$ 30,000	$ 135,000	$ 135,000	$ 102,000	$ 102,000	$ 75,000	$ 75,000	$ 69,000	$ -	$ -	$ -	$ -	$ 3,444,307	$ 8,053,957									
First Nations	$ 800,000	$ 46,000	$ 175,000	$ 175,000	$ 95,000	$ 95,000	$ 86,000	$ 86,000	$ 6,000	6000	6000	$ 6,000	$ 6,000	$ 6,000	$ 6,000									
AFUDC																								
SUBTOTAL PROJECT COSTS		$ 1,199,668	$ 1,719,915	$ 2,074,729	$ 2,195,899	$ 2,209,452	$ 2,919,891	$ 3,824,948	$ 3,827,410	$ 3,788,748	$ 3,723,100	$ 1,858,355	$ 1,975,179	$ 5,485,030	$ 33,183,001	$ 21,246,070	$ 20,116,343	$ 65,847,744	$ 64,698,586	$ 64,121,223	$ 17,280,207	$ 19,842,413	$ 14,999,249	$ 2,556,025
Contingency/Risk	$ -								$ -															$ -
OVERALL PROJECT VALUE	$ 360,918,183								$ 19,971,911															$ 340,721,273

ASSUMPTIONS/BASIS/CLARIFICATIONS

Development Phase ends with LTC filing. Project development will continue through LTC period.
Assumes 30-40% design complete at the end of the development phase ready for a bid for final design & construct.
EA cost estimate from Stantec assumes only 25% of the line route will require detail field survey for EA purposes.
Assumes that HST tax is not applicable to the Project.
Assumes that no agency cost recovery agreements are required for EA process.
Construction cost models listed as average, are averages of extroploted and BUE values.
See individual tabs for item estimate basis.
Where cashflow is not itemized then costs are distributed on a 1/3rds 2/3rds basis. THIS IS NOT BASED ON A RESOURCE LOADED SCHEDULE
Excludes Contingency Risk items (unless expressly identified).
Excludes CWIP (unless expressly identified).
Excludes Surcharge.

Mid American Transmission/RES Canada
Ontario Energy Board
Cost Model Bid Proposal
12/20/2012

Reference Design - Preliminary Preferred Route

Cost Model Type	AVG
230kV Double ALT Lattice	C

Item Description		**Development Phase**								**Construction: LTC Review Period**				**Construction: Delivery Phase**										**Close out**
		2013		**2014**				**2015**				**2016**				**2017**				**2018**				**2019**
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
Major Contracts																								
Transmission Line Construction/Engineering/Management	$ 103,580,721														$ 5,754,485	$ 5,754,485	$ 5,754,485	$ 23,017,938	$ 23,017,938	$ 23,017,938	$ 5,754,485	$ 5,754,485	$ 2,877,242	$ 2,877,242
Transmission Line Materials/Equipment	$ 241,688,350														$ 13,427,131	$ 13,427,131	$ 13,427,131	$ 53,708,522	$ 53,708,522	$ 53,708,522	$ 13,427,131	$ 13,427,131	$ 13,427,131	
Planning Studies & Cost Benefit Analysis	$ 550,000	$ 125,000	$ 250,000	$ 125,000			$ 20,000	$ 20,000	$ 10,000															
Owners Engineer (Pre-Construction)	$ 17,212,960			$ 430,324	$ 860,648	$ 860,648	$ 1,721,296	$ 2,581,944	$ 2,581,944	$ 2,581,944	$ 2,581,944	$ 860,648	$ 860,648	$ 860,648	$ 430,324									
Owner Engineer (Construction Phase)	$ 4,664,688														$ 466,469	$ 699,703	$ 699,703	$ 699,703	$ 699,703	$ 699,703	$ 233,234	$ 233,234	$ 116,617	$ 116,617
Route Selection Services	$ 82,500	$ 41,250	$ 41,250	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -									
Environmental Assessment	$ 1,896,614	$ 142,246	$ 142,246	$ 189,661	$ 189,661	$ 208,628	$ 208,628	$ 208,628	$ 189,661	$ 208,628	$ 189,661	$ 18,966	$ -	$ -										
Stakeholder Outreach	$ 544,865	$ 40,865	$ 40,865	$ 68,108	$ 68,108	$ 68,108	$ 68,108	$ 54,487	$ 54,487	$ 54,487	$ 27,243	$ -	$ -	$ -										
Aboriginal Consultation	$ 98,420	$ 9,842	$ 12,303	$ 12,303	$ 12,303	$ 12,303	$ 12,303	$ 9,842	$ 9,842	$ 4,921	$ 2,461	$ -	$ -											
Aboriginal Consultation (Legal)	$ 250,000	$ 50,000	$ 50,000	$ -	$ -	$ -	$ -	$ -	$ 100,000	$ 50,000	$ -	$ -	$ -	$ -										
Non EA permitting	$ 468,724	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,181	$ 117,181	$ 117,181	$ 117,181	$ -	$ -									
Construction Inspection/Management	$ 8,143,438														$ 452,413	$ 452,413	$ 452,413	$ 1,809,653	$ 1,809,653	$ 1,809,653	$ 452,413	$ 452,413	$ 452,413	
Enviromental Inspection Contractor	$ 5,281,375														$ 293,410	$ 293,410	$ 293,410	$ 1,173,639	$ 1,173,639	$ 1,173,639	$ 293,410	$ 293,410	$ 293,410	
Vegetation Management	$ 11,270,000														$ 3,381,000	$ 3,381,000	$ 2,254,000	$ 1,690,500	$ 563,500					
Install & Maintain Man Camps	$ 12,795,266														$ 3,838,580	$ 1,096,737	$ 1,096,737	$ 1,096,737	$ 1,096,737	$ 1,096,737	$ 1,096,737	$ 1,096,737	$ 1,279,526.6	
Spare Parts Facility	$ 1,000,000																					$ 775,000		
Capitalized Spare Parts	$ 2,416,883																					$ 2,416,883		
Internal (MAT/RES)																								
Executive Management	$ 738,738	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 63,063	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ -
Project Management	$ 8,869,661	$ 326,726	$ 331,094	$ 335,462	$ 352,934	$ 357,302	$ 357,302	$ 407,971	$ 424,570	$ 435,926	$ 467,376	$ 489,216	$ 543,379	$ 414,960	$ 414,960	$ 414,960	$ 414,960	$ 414,960	$ 393,120	$ 393,120	$ 393,120	$ 327,600	$ 262,080	$ 196,560
Engineering Management	$ 1,273,545	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 45,045	$ 45,045	$ 45,045	$ 24,570	$ 24,570	$ 24,570	$ 24,570	$ 24,570	$ 24,570
Transmission/Planning	$ 245,700	$ 81,900	$ 81,900	$ 81,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Expenses	$ 836,382	$ 44,936	$ 45,154	$ 45,373	$ 42,151	$ 42,370	$ 42,370	$ 47,155	$ 47,985	$ 48,553	$ 50,126	$ 51,218	$ 54,827	$ 46,153	$ 46,153	$ 23,901	$ 23,901	$ 23,901	$ 21,785	$ 21,785	$ 21,785	$ 18,509	$ 15,233	$ 11,057
Material Procurement (included in construction contracts)																								
Miscellaneous Costs																								
Legal Fees	$ 1,500,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 50,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 200,000	$ 175,000	$ 150,000	$ 125,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	
Media Relations/Community	$ 1,000,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	
ROW Costs																								
Right-of-Way Labor & Legal	$ 3,257,560	$ 95,813	$ 250,013	$ 320,013	$ 325,013	$ 315,013	$ 197,813	$ 149,813	$ 99,813	$ 47,000	$ 47,000	$ 47,000	$ 107,000	$ 371,862	$ 884,398									
ROW/Easements	$ 12,221,264	$ 30,000	$ 135,000	$ 135,000	$ 102,000	$ 102,000	$ 75,000	$ 75,000	$ 69,000	$ -	$ -	$ -	$ -	$ 3,444,307	$ 8,053,957									
First Nations	$ 800,000	$ 46,000	$ 175,000	$ 175,000	$ 95,000	$ 95,000	$ 86,000	$ 86,000	$ 6,000	6000	6000	$ 6,000	$ 6,000	$ 6,000	$ 6,000									
AFUDC																								
SUBTOTAL PROJECT COSTS		$ 1,199,668	$ 1,719,915	$ 2,083,234	$ 2,212,908	$ 2,226,461	$ 2,953,909	$ 3,875,974	$ 3,878,436	$ 3,839,775	$ 3,774,127	$ 1,875,364	$ 1,992,188	$ 5,502,039	$ 37,782,386	$ 25,806,802	$ 24,654,802	$ 83,773,616	$ 82,602,186	$ 82,013,686	$ 21,764,903	$ 24,887,990	$ 18,816,241	$ 3,226,046
Contingency/Risk	$ -								$ -															$ -
OVERALL PROJECT VALUE	$ 442,687,654								$ 20,150,504															$ 422,312,150

ASSUMPTIONS/BASIS/CLARIFICATIONS

Development Phase ends with LTC filing. Project development will continue through LTC period.
Assumes 30-40% design complete at the end of the development phase ready for a bid for final design & construct.
EA cost estimate from Stantec assumes only 25% of the line route will require detail field survey for EA purposes.
Assumes that HST tax is not applicable to the Project.
Assumes that no agency cost recovery agreements are required for EA process.
Construction cost models listed as average, are averages of extroploted and BUE values.
See individual tabs for item estimate basis.
Where cashflow is not itemized then costs are distributed on a 1/3rds 2/3rds basis. THIS IS NOT BASED ON A RESOURCE LOADED SCHEDULE
Excludes Contingency Risk items (unless expressly identified).
Excludes CWIP (unless expressly identified).
Excludes Surcharge.

Mid American Transmission/RES Canada
Ontario Energy Board
Cost Model Bid Proposal
12/20/2012

Reference Design - Reference Route

Cost Model Type	AVG
230kV Double BASE Lattice	B

Item Description		Development Phase								Construction: LTC Review Period				Construction: Delivery Phase										Close out
		2013		2014				2015				2016				2017				2018				2019
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
Major Contracts																								
Transmission Line Construction/Engineering/Management	$ 102,267,627														$ 5,681,535	$ 5,681,535	$ 5,681,535	$ 22,726,139	$ 22,726,139	$ 22,726,139	$ 5,681,535	$ 5,681,535	$ 2,840,767	$ 2,840,767
Transmission Line Materials/Equipment	$ 238,624,464														$ 13,256,915	$ 13,256,915	$ 13,256,915	$ 53,027,659	$ 53,027,659	$ 53,027,659	$ 13,256,915	$ 13,256,915	$ 13,256,915	
Planning Studies & Cost Benefit Analysis	$ 550,000	$ 125,000	$ 250,000	$ 125,000			$ 20,000	$ 20,000	$ 10,000															
Owners Engineer (Pre-Construction)	$ 16,872,783			$ 421,820	$ 843,639	$ 843,639	$ 1,687,278	$ 2,530,918	$ 2,530,918	$ 2,530,918	$ 2,530,918	$ 843,639	$ 843,639	$ 843,639	$ 421,820									
Owner Engineer (Construction Phase)	$ 4,572,500														$ 457,250	$ 685,875	$ 685,875	$ 685,875	$ 685,875	$ 685,875	$ 228,625	$ 228,625	$ 114,313	$ 114,313
Route Selection Services	$ 82,500	$ 41,250	$ 41,250	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -									
Environmental Assessment	$ 1,896,614	$ 142,246	$ 142,246	$ 189,661	$ 189,661	$ 208,628	$ 208,628	$ 208,628	$ 189,661	$ 208,628	$ 189,661	$ 18,966	$ -	$ -										
Stakeholder Outreach	$ 544,865	$ 40,865	$ 40,865	$ 68,108	$ 68,108	$ 68,108	$ 68,108	$ 54,487	$ 54,487	$ 54,487	$ 27,243	$ -	$ -	$ -										
Aboriginal Consultation	$ 98,420	$ 9,842	$ 12,303	$ 12,303	$ 12,303	$ 12,303	$ 12,303	$ 9,842	$ 9,842	$ 4,921	$ 2,461	$ -	$ -											
Aboriginal Consultation (Legal)	$ 250,000	$ 50,000	$ 50,000	$ -	$ -	$ -	$ -	$ -	$ 100,000	$ 50,000	$ -	$ -	$ -	$ -										
Non EA permitting	$ 468,724	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,181	$ 117,181	$ 117,181	$ 117,181	$ -	$ -									
Construction Inspection/Management	$ 7,982,500														$ 443,472	$ 443,472	$ 443,472	$ 1,773,889	$ 1,773,889	$ 1,773,889	$ 443,472	$ 443,472	$ 443,472	
Enviromental Inspection Contractor	$ 5,177,000														$ 287,611	$ 287,611	$ 287,611	$ 1,150,444	$ 1,150,444	$ 1,150,444	$ 287,611	$ 287,611	$ 287,611	
Vegetation Management	$ 11,047,273														$ 3,314,182	$ 3,314,182	$ 2,209,455	$ 1,657,091	$ 552,364					
Install & Maintain Man Camps	$ 12,633,060														$ 3,789,918	$ 1,082,834	$ 1,082,834	$ 1,082,834	$ 1,082,834	$ 1,082,834	$ 1,082,834	$ 1,082,834	$ 1,263,306.0	
Spare Parts Facility	$ 1,000,000																					$ 775,000		
Capitalized Spare Parts	$ 2,386,245																					$ 2,386,245		
Internal (MAT/RES)																								
Executive Management	$ 738,738	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 63,063	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ 18,018	$ -
Project Management	$ 8,869,661	$ 326,726	$ 331,094	$ 335,462	$ 352,934	$ 357,302	$ 357,302	$ 407,971	$ 424,570	$ 435,926	$ 467,376	$ 489,216	$ 543,379	$ 414,960	$ 414,960	$ 414,960	$ 414,960	$ 414,960	$ 393,120	$ 393,120	$ 393,120	$ 327,600	$ 262,080	$ 196,560
Engineering Management	$ 1,273,545	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 45,045	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 90,090	$ 45,045	$ 45,045	$ 45,045	$ 24,570	$ 24,570	$ 24,570	$ 24,570	$ 24,570	$ 24,570
Transmission/Planning	$ 245,700	$ 81,900	$ 81,900	$ 81,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Expenses	$ 836,382	$ 44,936	$ 45,154	$ 45,373	$ 42,151	$ 42,370	$ 42,370	$ 47,155	$ 47,985	$ 48,553	$ 50,126	$ 51,218	$ 54,827	$ 46,153	$ 46,153	$ 23,901	$ 23,901	$ 23,901	$ 21,785	$ 21,785	$ 21,785	$ 18,509	$ 15,233	$ 11,057
Material Procurement (included in construction contracts)																								
Miscellaneous Costs																								
Legal Fees	$ 1,500,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 50,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 200,000	$ 175,000	$ 150,000	$ 125,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	
Media Relations/Community	$ 1,000,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	
ROW Costs																								
Right-of-Way Labor & Legal	$ 3,257,560	$ 95,813	$ 250,013	$ 320,013	$ 325,013	$ 315,013	$ 197,813	$ 149,813	$ 99,813	$ 47,000	$ 47,000	$ 47,000	$ 107,000	$ 371,862	$ 884,398									
ROW/Easements	$ 12,221,264	$ 30,000	$ 135,000	$ 135,000	$ 102,000	$ 102,000	$ 75,000	$ 75,000	$ 69,000	$ -	$ -	$ -	$ -	$ 3,444,307	$ 8,053,957									
First Nations	$ 800,000	$ 46,000	$ 175,000	$ 175,000	$ 95,000	$ 95,000	$ 86,000	$ 86,000	$ 6,000	6000	6000	$ 6,000	$ 6,000	$ 6,000	$ 6,000									
AFUDC																								
SUBTOTAL PROJECT COSTS		$ 1,199,668	$ 1,719,915	$ 2,074,729	$ 2,195,899	$ 2,209,452	$ 2,919,891	$ 3,824,948	$ 3,827,410	$ 3,788,748	$ 3,723,100	$ 1,858,355	$ 1,975,179	$ 5,485,030	$ 37,391,278	$ 25,454,347	$ 24,324,620	$ 82,680,855	$ 81,531,697	$ 80,954,333	$ 21,488,485	$ 24,580,934	$ 18,576,285	$ 3,187,266
Contingency/Risk	$ -								$ -															$ -
OVERALL PROJECT VALUE	$ 437,197,424								$ 19,971,911															$ 417,000,514

ASSUMPTIONS/BASIS/CLARIFICATIONS

Development Phase ends with LTC filing. Project development will continue through LTC period.
Assumes 30-40% design complete at the end of the development phase ready for a bid for final design & construct.
EA cost estimate from Stantec assumes only 25% of the line route will require detail field survey for EA purposes.
Assumes that HST tax is not applicable to the Project.
Assumes that no agency cost recovery agreements are required for EA process.
Construction cost models listed as average, are averages of extroploted and BUE values.
See individual tabs for item estimate basis.
Where cashflow is not itemized then costs are distributed on a 1/3rds 2/3rds basis. THIS IS NOT BASED ON A RESOURCE LOADED SCHEDULE
Excludes Contingency Risk items (unless expressly identified).
Excludes CWIP (unless expressly identified).
Excludes Surcharge.

TAB P-4-3

Construction Phase – Cost of Required Transmission Station Modifications

In the Board's stakeholder meetings, there were references to increasing the transfer capacity for Hydro One's existing East West Transmission line that currently ranges from 175 MW to 350 MW (depending on operating criteria), initially to 450 MW, and ultimately to 650 MW as indicated in the OPA's March 23, 2013 presentation[1], "Reactive compensation is to be sufficient to support an initial interface transfer of approximately 450 MW. Additional compensation and station facilities [are] to be provided as required at a later stage to operate at the 650 MW capability."

One of the unique advantages of Applicant's Preferred Design is that the full transfer capacity (684 MW) could be installed at once or, alternatively, it allows Hydro One to stage the upgrades for interconnecting substations to the EWTL to make incremental transfer capacity additions when and if they are needed. The electricity demand scenarios that are included in the OPA's 2011 long-term electricity outlook for the Northwest indicate that the full transfer capacity of 650 MW that is stipulated in the Board's definition of the EWTL, is unlikely to be required by the initial EWTL COD. As illustrated below in Table P-8, substation upgrades can be staged over time to achieve incremental increases in line capacity ranging from 387 MW to 684 MW[2], when and if such transfer capacities and associated upgrades are needed.

---

[1] OPA Presentation at OEB Designation stakeholder meeting, March 23, 2012: OPA's Role and Background/Highlights of the East-West Tie Line

[2] IESO Feasibility Study, December 29, 2012

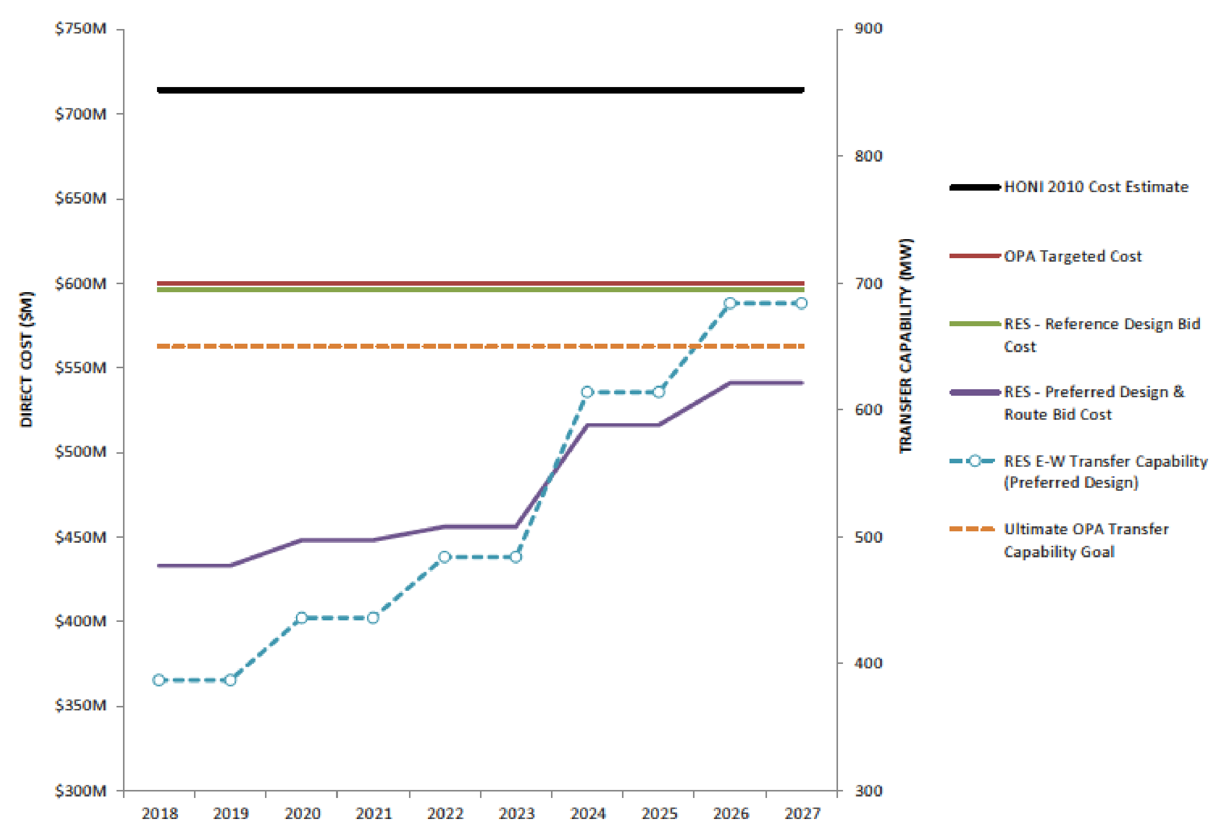
Table P-8

Stage	Facilities Added	Total Installed Transfer Capacity (MW)	Incremental Transfer Capacity Added (MW)
1	transmission line constructed from Wawa TS to Lakehead TS with an interconnection at Marathon TS	387	
2	series compensation added between Wawa TS and Marathon TS	436	49
3	series compensation added between Marathon TS and Lakehead TD	484	48
4	shunt capacitors added at Lakehead TS and Marathon TS, static VAr compensator added at Marathon TS (without series compensation between Marathon TS and Lakehead TS as described in Stage 3)	614	130
5	stage 4 plus series compensation added between Marathon TS and Lakehead TS	684	70

Capacity upgrades would be achieved as described previously and as outlined in Table P-8 above.

Adding transfer capacity in stages and only if and when required by system demand, as proposed in the Preferred Design, would defer or avoid altogether, the expenditure of the significant capital costs of stages 2 through 5. This would translate into substantial savings for Ontario ratepayers. A graph that compares the OPA’s estimate of the cost of constructing the Reference Design with the Applicant’s estimate of the cost of constructing its Preferred Design is included in Figure P-3 below. The table that follows Figure P-3 shows the magnitude of the capital costs deferred or avoided altogether for stages 2 through 5; these range between $55 million and $163 million.

Figure P-3: EWTL, Station and Interconnection Costs



Design Scenario for Preliminary Preferred Route	Circuits	Transfer Capacity (MW)	Bid Amount	Other Costs (Hydro One) ($M)	Total Costs ($M)	Avoided Costs ($M)	Incremental Cost ($M/MW)
Reference Design	2	650	$493	$103	$596	Base	NA
Preferred Design (Stage 1)	1	387	$413	$20	$433	$163	NA
Preferred Design (Stage 2)	1	436	$413	$35	$448	$148	$0.31
Preferred Design (Stage 3)	1	484	$413	$43	$456	$140	$0.17
Preferred Design (Stage 4)	1	614	$413	$103	$516	$80	$0.46
Preferred Design (Stage 5)	1	684	$413	$128	$541	$55	$0.36

Note: Avoided costs calculated as the sum of the Bid Amount plus Hydro One costs for each stage, subtracted from the total costs for the Reference Design ($596 million).

Rate payers will benefit from the deferral of the costs of capacity upgrades because of savings from the avoided costs of asset depreciation, property taxes, operating and maintenance expenses on the incremental plant and the return on rate base. Further, assuming each of the additional upgrades identified in stages 2 to 5 of Figure P-3 are made every alternate year over an 8 year period, the value of savings to rate payers from the deferral are approximately $62.5 million until 2026. This estimate is based on a 50 year depreciable life for the assets with 2 percent property tax rate, 1 percent of cost for operating and maintenance and return on rate base at the current Board approved cost of capital parameters of 8.93 percent for return on equity and 4.06 percent for deemed long-term cost of debt. If the demand growth is not realized, the upgrades would be further delayed resulting in even higher savings. Table P-9 sets out a breakdown of the $62.5 million savings.

Table P-9

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate base with delays		$433	$433	$448	$448	$456	$456	$516	$516	$541	$541
Rate base savings		$108	$108	$93	$93	$85	$85	$25	$25	$0	$0
Equity (1)	40%	$43.20	$43.20	$37.20	$37.20	$34.00	$34.00	$10.00	$10.00	$0.00	$0.00
Debt (1)	60%	$64.80	$64.80	$55.80	$55.80	$51.00	$51.00	$15.00	$15.00	$0.00	$0.00
Returns	8.93%	$1.93	$3.86	$3.32	$3.32	$3.04	$3.04	$0.89	$0.89	$0.00	$0.00
	4.06%	$1.32	$2.63	$2.27	$2.27	$2.07	$2.07	$0.61	$0.61	$0.00	$0.00
Depreciation	50	$1.08	$2.16	$1.86	$1.86	$1.70	$1.70	$0.50	$0.50	$0.00	$0.00
Property taxes	2%	$1.08	$2.16	$1.86	$1.86	$1.70	$1.70	$0.50	$0.50	$0.00	$0.00
O&M	1%	$0.54	$1.08	$0.93	$0.93	$0.85	$0.85	$0.25	$0.25	$0.00	$0.00
Total savings	$62.53	$5.94	$11.89	$10.24	$10.24	$9.36	$9.36	$2.75	$2.75	$0.00	$0.00

(1) Assumes a period of no cash tax payment and hence no gross-up for income taxes for demonstration purposes. Savings could be even higher if otherwise.

Given the foregoing, Applicant's Preferred Design provides potential cost savings to ratepayers that go beyond the line portions of the Project and its cost proposals.

TAB P-5-1

Risk Allocation Proposal

The Applicant has analysed the scheduling and cost-related risks of developing and constructing the EWTL from the perspective of probability and severity. The results of this analysis were taken into consideration in developing Applicant's risk allocation strategies, Development and Construction Cost Proposal and its Bid Amounts.

Development Risks

The Applicant has identified six significant risks that may affect the schedule and costs during the development phase of the Project, and has made assessments of the likelihood and severity of each risk in Table P-10 below. As indicated in Table P-10, for each risk the cost and schedule impact has been identified, as well as the likelihood of occurrence. In addition, a high level mitigation strategy has been discussed for each item, as applicable.

Table P-10

				Schedule Exposure		Cost Exposure	
Item	**Category**	**Issue/ Description**	**Mitigation Strategy**	**Likelihood**	**Severity**	**Likelihood**	**Severity**
1	Design/ Engineering/ Management	Accuracy of baseline assumptions for route, line length, general scope inclusions and project plan changes	Develop project plan and work with all stakeholder parties to identify, define and resolve issues as they arise	Somewhat Likely	Minor	Somewhat Likely	Minor
2	Option Agreements for Land and Road Access Rights (this matter is an Exception for the purposes of the Bid Amounts)	Unanticipated problems in securing options for land and road access rights	Early and proactive outreach with all private, public, and Crown entities from which land rights will be needed. Extensive work already completed by Applicant in connection with this Application	Not Likely	Minor	Somewhat Likely	Moderate

				Schedule Exposure		Cost Exposure	
Item	**Category**	**Issue/ Description**	**Mitigation Strategy**	**Likelihood**	**Severity**	**Likelihood**	**Severity**
3	Stakeholder Consultations	Unanticipated challenges in addressing and mitigating stakeholder concerns	Early and proactive outreach involving public meetings, mass mailings, a website, newspaper postings and other similar outreach strategies	Not Likely	Minor	Not Likely	Minor
4	First Nation and Métis Consultation	Unanticipated challenges in negotiating impact benefit agreements	Early and proactive engagement with identified First Nation and Métis communities assisted by John Beaucage. Early coordination with MEI through an MOU to be executed upon designation	Somewhat Likely	Moderate	Somewhat Likely	Minor
5	Project Need & COD	Unanticipated requirements to support OPA in the preparation of a benefit/cost analysis	Close coordination with OPA and the use of advisors experienced in such matters (E3 or Brattle)	Not Likely	Minor	Not Likely	Minor
6	Route Selection	Unanticipated challenges in identifying and selecting a final route	Input from stakeholder and First Nation and Métis consultation processes to identify route refinements in conjunction with design and engineering input; substantial work already completed by Applicant	Not Likely	Minor	Not Likely	Minor

Construction Risks

Applicant has identified 16 significant risks that may affect the schedule and costs during the construction phase of the Project and it has made assessments of the likelihood and severity of each risk as set out in Table P-11 below. As indicated Table

P-11, the risks have been labeled with cost and schedule impacts, as well as the likelihood of occurrence. In addition, a high level mitigation strategy has been discussed for each item as applicable.

Table P-11

				Schedule Exposure		Cost Exposure	
Item	**Category**	**Issue/ Description**	**Mitigation Strategy**	**Likelihood**	**Severity**	**Likelihood**	**Severity**
1	Construction	Unavailability of local labour, requiring additional non-Ontario based resources. Associated tax, inducement and travel cost risks.	Develop contractor relationships based on development team experience. Local promotion program to garner interest from local contractors. First Nation and Métis participation in accordance with impact and benefits agreements, including provision of training. Use of an experienced and well resourced EPC contractor	Somewhat Likely	Minor	Somewhat Likely	Major
2	Construction	Unavailability and cost of materials and supplies	Competitive bids from Canadian suppliers; use of man-camps and FN contractors. Use of an experienced and well resourced EPC contractor	Somewhat Likely	Minor	Somewhat Likely	Major
3	Construction (this matter is an Exception for the purposes of the Bid Amounts)	Accuracy of baseline assumptions for route, line length, general scope inclusions and project plan. Route modifications that increase the total length to not more than 410	Coordinate route selection, line engineering studies and survey work to provide most efficient design solutions.	Somewhat Likely	Moderate	Somewhat Likely	Major

				Schedule Exposure		Cost Exposure	
Item	**Category**	**Issue/ Description**	**Mitigation Strategy**	**Likelihood**	**Severity**	**Likelihood**	**Severity**
		km through engineering adjustment, design limitations and topographic influences.					
4	Construction	Prolonged and/or unanticipated inclement weather	Flexible tasks and schedules to optimize weather conditions. Use of an experienced and well resourced EPC contractor	Somewhat Likely	Moderate	Somewhat Likely	Moderate
5	Legal (this matter is an Exception for the purposes of the Bid Amounts)	Unanticipated litigation and additional costs to secure land rights needed for access, construction, and operations	Use of experienced Ontario counsel and MNR policy where applicable	Somewhat Likely	Moderate	Somewhat Likely	Minor
6	Construction	Unanticipated road improvements and helicopter usage*	Coordination with Hydro One and landowners. Use of an experienced and well resourced EPC contractor	Somewhat Likely	Minor	Somewhat Likely	Moderate
7	Design/Engineering	Unanticipated changes in select structure & tower requirements**	Owners Engineer to be engaged early in development phase to work with Environmental, ROW and project development team to optimize the design for the most efficient structure locations. Owner's Engineer to refine tower specifications. Use of an experienced and well resourced EPC contractor	Not Likely	Minor	Somewhat Likely	Moderate
8	Design/ Engineering	Unanticipated design for extreme winds	Utilize latest wind data during initial design phase.	Not Likely	Minor	Not Likely	Moderate

				Schedule Exposure		Cost Exposure	
Item	**Category**	**Issue/ Description**	**Mitigation Strategy**	**Likelihood**	**Severity**	**Likelihood**	**Severity**
9	Design/ Engineering	Unanticipated foundation requirements ***	Geotechnical investigations, site-inspections, and timely reaction to local unexpected conditions. Use of an experienced and well resourced EPC contractor	Somewhat Likely	Minor	Somewhat Likely	Moderate
10	Design/ Engineering	Unanticipated grounding requirements	Engage grounding experts and specialist vendors	Not Likely	Minor	Very Likely	Moderate
11	Construction	Unanticipated site requirements and costs to clear vegetation and obstructions within the path of the EWTL	Use of an experienced and well resourced EPC contractor and First Nation and Métis contracting including performance incentives; coordination with Hydro One.	Not Likely	Minor	Somewhat Likely	Minor
12	Design/ Engineering	Localized need to expand 50 m corridor width	Coordination with Hydro One and landowners.	Not Likely	Minor	Somewhat Likely	Minor
13	Design/ Engineering	Unanticipated additional transmission line crossings of existing East-West Transmission line	Participation in the final route selection process to identify the most cost-effective and environmentally acceptable route refinements	Not Likely	Minor	Somewhat Likely	Minor
14	Permits (this matter is an Exception for the purposes of the Bid Amounts)	Unanticipated problems in securing permits by no later than six months after the completion of LTC hearings	Early and proactive efforts to secure permits during and within six months of the end of LTC hearings	Somewhat Likely	Moderate	Somewhat Likely	Minor
15	Design/ Engineering	Line Transposition Structures	Owners Engineer to define final requirements	Not Likely	Minor	Somewhat Likely	Minor
16	Legal	Unanticipated additional support required in OEB	Use of experienced Ontario counsel and external	Not Likely	Minor	Somewhat Likely	Minor

				Schedule Exposure		Cost Exposure	
Item	Category	Issue/ Description	Mitigation Strategy	Likelihood	Severity	Likelihood	Severity
		Designation & LTC proceedings	service providers as needed				

* Item 6:

- Unknown grade and shallow subgrade conditions.
- Detailed topographic assessment not yet done; actual cut/fill, alignment adjustments/reroutes due to extreme grades, or 3D evaluation not done
- Actual transport plan (final) not developed or optimized.
- Assumed the Applicant can use existing ROW; if not and new access roads are required along the entire new ROW, this is not accounted for.
- Access roads increased as number of structures not final (no final design/layout).
- Unknown restrictions to access (if any) may preclude certain access routes, etc.

**Item 7

- H-frame structure weights estimated using design software with estimated loading. Due to height additional weight due to multiple shaft flange joints was estimated. Weights from an H-frame 345 project were also utilized.
- H-frame structure quantities are estimates based on average span length and not terrain spotting. Terrain restrictions could increase quantities or decrease
- Clearances to water bodies range from 12.5 m to 18.5 m. There are many crossings at mid-span which could increase height.
- Snow clearance; line clearance height after snow fall.
- Tower reactions may vary some as exact tower heights and spans were not used. Average spans utilized have some variations.
- Galloping requirements could increase the phase spacing (middle arm of the tower and increase weight).

- Hotline work is required for the structure configuration. This was roughly incorporated but not verified for phase spacing and clearance to structure face.

- Single circuit lattice deadend tower weights were estimated from BPA tower which has an extreme ice condition of 3 inches. Weights were reduced based on engineering judgment.

***Item 9

- Final ratio of foundation types unknown (no final breakdown of subgrade conditions).

- Potential increase in quantity of rock areas.

- No geotech data available, assumed foundation design/mix.

- Unknown final layout/number of structures known impacting foundation design/scope.

- Snow creep; differential melting impacts loads on structures.

Development and Construction Cost Proposal

Given the foregoing, the Applicant has devised an innovative risk-sharing commercial proposal in which the Applicant is rewarded or penalized for its success in controlling risks and this proposal is structured to transfer substantial risk to the Applicant for the benefit of the rate payer. The Applicant through the experience of the RES Group and the MidAmerican Group with the development and construction of projects similar to the EWTL and based on its diligence in review and understanding of the entire Project scope and schedule has assumed substantial risks in its Development and Construction Cost Proposal.

The Applicant has proposed a Preliminary Preferred Route and Preferred Design that provides superior electrical performance, immediate improvement to system reliability, ability for future staged transmission system capacity increases when needed and reduced initial installed cost and overall lower cost to customers when full OPA designated ETWL capacity is required. Most importantly the Applicant's Development and Construction Cost Proposal will provide for lower costs to ratepayers, over both the short term and longer term when compared to the Reference Design. The Applicant does however appreciate that the Board may wish to direct the Applicant to develop and construct the EWTL based on the Reference Design over the Preliminary Preferred Route and has proposed a Bid Amount for this option. Additionally, the Applicant is willing and able to apply its Development and Construction Cost Proposal described below to the other two development scenarios for the EWTL involving the Reference Route, but at this time, the Applicant's cost estimates are not sufficiently definitive to establish Bid Amounts for such options. Such costs could be defined subsequent to designation if desired by the Board and the Applicant was to construct the EWTL pursuant to one of the other two options.

As discussed above, the Applicant's development and construction cost estimates for the EWTL pursuant to the Preferred Design and the Reference Design over the Preliminary Preferred Route are definitive. Accordingly the Applicant proposes a firm Bid Amount for the development and construction of the EWTL over the Preliminary Preferred Route of $413.4 million for the Preferred Design and $493.7 million for the Reference Design, subject to escalation. With respect to the Bid Amounts, the Applicant proposes to be bound by a unique and innovative risk-sharing mechanism:

1. an incentive rate methodology that rewards RES Transmission for completing the development and construction of the Project for less than its Bid Amount and penalizes RES Transmission for exceeding the Bid Amount, as follows:

    - **costs underages:** for each year that the EWTL is in service, the value of its Board-approved rate base would be reduced by the amount of any cost underages (the "**Subtracted Amount**"). Sixty percent of the remainder would earn a return at the Board's deemed cost of long-term debt, determined annually, and 40 percent of the remainder would earn a return at the return on equity determined by the Board, annually ("**ROE**"). Forty percent of the Subtracted Amount would earn an incentive return equal to the sum of the ROE and 300 basis points. Sixty percent of the Subtracted

Amount would earn a return at the Board's deemed cost of long-term debt, determined annually;

- **cost overages:** for each year that the EWTL is in service, the ROE that would otherwise be earned on 40 percent of any prudently incurred cost overages would be reduced and RES Transmission would instead earn only the deemed cost of long-term debt, as determined by the OEB annually, on 100 percent of such overages; and

- **exceptions:** The equity portion (i.e., 40%) of the difference between the actual costs incurred in four cost categories over which the Applicant has little or no control and the estimates of such costs that are embedded in the Bid Amounts in the four categories, up to a specified limit , would earn a return at the ROE determined by the Board, annually, and would not be subject to the penalty that would be otherwise applicable to cost overages under the Applicant's proposed incentive rate methodology. The four categories are as follows: land acquisition (up to $15.5 million); First Nation and Métis participation costs and accommodation (up to $1.0 million); environmental and permitting costs (up to $2.5 million); and line costs in respect of a total line length that exceeds 410 km ($1 million for each additional km);

2. the utilization of US GAAP for regulatory accounting, reporting and rate-making purposes; and

3. the calculation of interest for CWIP at a blended rate as discussed in Exhibit B-1-1.

Exceptions

In addition to the risk items identified and included within tables above, previous experience with similar RES Group and the MidAmerican Group projects suggests a limited number of items which are considered significant risks, influenced by, decisions, factors or entities beyond the Applicant's reasonable control. These matters are referred to as Exceptions. The Applicant proposes that the Exceptions above an identified threshold be excluded from the adjustment of Applicant's ROEs under the Development and Construction Cost Proposal, due to the unknown, unquantifiable and uncontrollable nature of the risks presented by these Exceptions. The results of the Applicant's risk and cost analysis, in relation to the Exceptions, are set out in Table P-12 below.

Table P-12

Ref	Exception	Reason for Exception and Resolution Method
1	Route modifications that increase the total project length to more than 410 km due to regulatory, governmental , environmental agency or landowner actions or stipulations	The Applicant does not maintain control over the decisions and actions of such agencies, groups and individuals, though as part of its development plan, the Applicant fully intends to work closely with all such groups to garner as much cooperation, input and collaboration as possible. Therefore, if final route adjustments dictate additional line distance above 410 km based upon direction or requirement of any regulatory, governmental or environmental agency or landowner actions or stipulations, the incremental capital cost incurred will be set at $1 million per km to develop, engineer, procure and construct the line.
2	First Nation and Métis Participation and Accommodation costs in excess of $1 million	Each Bid Amount includes $1 million for First Nation and Métis participation and executed impact and benefits agreements. The OEB has indicated that it will not restrict participation to any particular type. Participation may include but not be limited to: training, education, sponsorships and community improvements, employment, and impact benefit agreements. Should it appear likely a cost impact in excess of $1 million may be incurred under this Exception whether through increased First Nation and Métis participation or otherwise, the Applicant will maintain appropriate records to substantiate cost or schedule impacts and notify the OEB of the same from time to time. The Applicant would utilize schedule analysis techniques to identify impacts on critical path items resulting from this Exception and develop a recovery plan in the event of delays.

Ref	Exception	Reason for Exception and Resolution Method
3	Unanticipated permitting requirements and costs, including environmental requirements and mitigation costs, in excess of $2.5 million in aggregate	Each Bid Amount includes for $2.5 million for normal and reasonable permitting activities, environmental studies and mitigations based upon the current permitting requirements and current recognized status of the various known species, historic mitigation practices and external consultants' experience for the species within the Project area. Should the MOE or other such ministry, group or agency require permitting activities, environmental studies and mitigations exceeding costs of $2.5 million, the Applicant will maintain appropriate records to substantiate cost or schedule impacts and notify the OEB of the same from time to time. The Applicant would utilize schedule analysis techniques to identify impacts on critical path items resulting from this Exception and develop a recovery plan for the same.
4	Property Acquisition, Land rights / Legal	Each Bid Amount includes $15.5 million for the acquisition of all land rights including access roads. This amount includes labour costs, legal costs, easements on private and Crown properties, as well as allowances for the purchase of easements across active and non-active timber and mining claims. While the Applicant's proposal is based upon its experience and a level of knowledge of property acquisition processes and costs within the area, the Applicant may encounter additional and excessive claims for compensation for property acquisition, particularly with regard to mining and timber rights. The Applicant will engage with the MNR, MNDMF and other agencies for opportunities to mitigate these costs. It is the Applicant's intention to report monthly to the OEB on status updates and forecasts on the progress of property acquisitions so all parties are aware of the trends and work collaboratively to mitigate potential negative cost impacts.

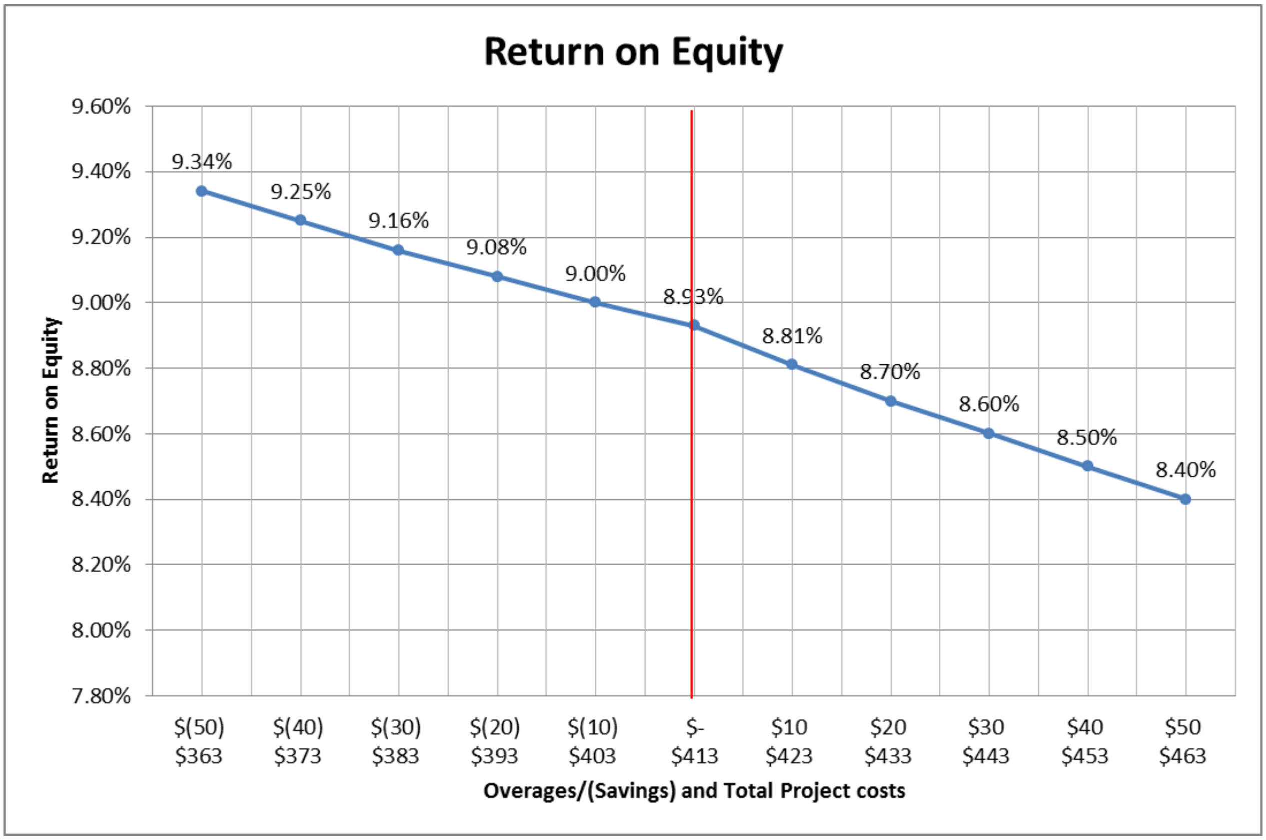
Risk Allocation Under Development and Construction Cost Proposal

It is the Applicant's view that its innovative cost proposal is favourable to rate payers and has been structured to transfer substantial risk from rate payers to the Applicant.

As shown in Figure P-6 below, which is based on an indicative return of equity, in a simple case of no Exceptions being applicable, no taxes and impacts from capital expenditures only, the increased rate of return the Applicant is permitted to claim due to savings made from its Bid Amount (in this case being the Bid Amount for the Preferred Design over the Preliminary Preferred Route) is lower than the decrease in its return on equity if there was a cost overage in the same amount. This is because of the smaller incentive of 300 basis points on savings that the Applicant is seeking, to the disincentive of 490 basis points for cost overages (based on the Board's current deemed cost of debt). In either case, ratepayers receive benefits from the lower rates – in case of savings because of reduced revenue requirements and in case of cost overages because of the lower return on equity that the Applicant is willing to earn on the amount of the overrun.

Figure P-6 is based on current cost of capital parameters for a return on equity of 8.93 percent, and a deemed long –term debt cost of 4.06 percent. Figure P-6 is for demonstration purposes only and does not commit to the Applicant to any particular rates of return. Actual rate applications will be based on the cost of capital parameters and methodology of the Board in force at the appropriate time.

Figure P-6



TAB P-6-1

Annual Operation & Maintenance Budget - Overview

The Applicant has significant experience in operating and maintaining transmission lines and will develop a comprehensive and definitive O&M Plan for the line during the development phase of the Project. The Applicant has in Exhibit F-5-1 set out the structure for its O&M Plan and how this will be developed further. The Applicant's estimated annual budget for O&M of the EWTL is $2.2 million. At this time the Project's O&M estimate does not include annual or periodically reoccurring expenses (that will not be capitalized) for:

- First Nation and Métis participation agreements and IBAs;
- annual costs for ongoing preservation of land and access rights;
- permit or licence upgrades or renewals;
- ongoing payments for environmental mitigation actions resulting from the EA;
- any new or changes is operating and maintenance requirements resulting from mandatory system reliably standards and guidelines established by IESO, NERC, NEPP and other regulatory bodies;
- any costs levied by Hydro One for interconnection point maintenance at the their transmission stations; and
- taxes.

The estimated annual O&M expenditure for each general category identified in Exhibit F-5-1 for the O&M Plan is explained further in Exhibit P-6-2.

TAB P-6-2

Annual Operating and Maintenance (O&M) Budget Estimates

Number	Category	Annual Estimate
1	Land Rights	To be determined in development phase
2	Annual Inspections and Testing	$ 1,000,000
3	Vegetation Management	$ 800,000
4	Systems Operations & Communications	To be determined in development phase
5	Compliance and Reporting	$ 25,000
6	Spare Equipment and Materials	$ 100,000
7	Unplanned outage responses/ Emergency Repairs and Restoration	$ 225,000
8	NERC Compliance Changes	To be determined in development phase
9	IESO Compliance	$ 25,000
10	Record Keeping	$ 20,000
11	Communications & Notifications	$ 5,000
12	First Nation and Métis participation and impact benefits agreements	To be determined in development phase
Total Annual Estimate		**$ 2,200,000**

TAB P-7-1

Example Calculations

This Exhibit P-7 illustrates with a series of examples, the incentive and penalty structure of the Development and Construction Cost Proposal proposed by the Applicant in this Application. These figures are for illustrative purposes only and represent hypothetical expenditures that are assumed to have passed the Board's customary prudence review. The cases below also assume the Board's rate of return on equity as determined by it in accordance with its cost of capital methodology is 8.93 percent.

The following summarizes the four scenarios demonstrated below:

- **Case 1:** Actual capital spent is more than the Bid Amount; the cost of Exceptions are more than the costs included in the Bid Amount for the same;
- **Case 2:** Actual capital spent is more than the Bid Amount; the cost of Exceptions are less than the costs included in the Bid Amount for the same;
- **Case 3:** Actual capital spent is less than the Bid Amount; the cost of Exceptions are more than the costs included in the Bid Amount for the same;
- **Case 4:** Actual capital spent is less than the Bid Amount; the cost of Exceptions are less than the costs included in the Bid Amount for the same.

In each case, it is assumed the EWTL is constructed pursuant to the Preferred Design over the Preliminary Preferred Route for which the Bid Amount is $413.4 million.

Case 1: Actual capital spent is more than the Bid Amount; the cost of Exceptions are more than the costs included in the Bid Amount for the same.

This case assumes the Project is built at a total cost of $428.4 million (as set out in Table P-13 below), the cost of Exceptions exceeds the costs included in the Bid Amount by $5 million and other overruns amount to $10 million.

Under the Applicant's Development and Construction Cost Proposal, the Applicant would include the additional $5 million Exception overage into the rate base eligible for an equity return at the rate determined by the Board in accordance with its cost of capital methodology. For the other additional expenditures of $10 million, the risk is assumed by the Applicant and the Applicant would seek to recover only the Board's deemed cost of debt on this amount in its rate applications. This results in annual savings of $0.2 million to customers and leaves the Applicant with an effective return on equity of 8.82 percent instead of the allowed 8.93 percent return.

Table P-13		**Case 1 (Higher total spend, higher actual exceptions)**			
($, in millions CAD)		Project bid	Total actual spent	Traditional rate making	Proposed rate making
Total project cost	(a)	413.4	428.4	428.4	428.4
Adjust for					
Exceptions embedded in cost above					
Land acquisition costs		15.5	19.5	19.5	19.5
Environmental and permitting costs		2.5	2.5	2.5	2.5
Aboriginal participation costs		1.0	1.0	1.0	1.0
Line distance greater than 410 km (Actual 411 km)		-	1.0	1.0	1.0
Total exceptions	(b)	19.0	24.0	24.0	24.0
Cost excluding exceptions	(c)=(a)-(b)	394.4	404.4	404.4	404.4
Allowed cost based on bid	(d)			404.4	394.4
Allowed exceptions	(e)			24.0	24.0
Cost overages on bid amount	(f)=(c)-(d)				10.0
Cost savings from bid amount	(g)				0.0
Traditional rate making rate base	(h)=(a)-(f)-(g)			428.4	418.4
Equity (40%)	(i)=(h)*0.4			171.4	167.4
Debt (60%)	(j)=(h)*0.6			257.0	251.0
Penalty return rate base	(f)				10.0
Equity (40%)	(k)=(f)*0.4				4.0
Debt (60%)	(l)=(f)*0.6				6.0
Allowed equity return	(p)			8.93%	8.93%
Allowed debt return	(q)			4.03%	4.03%
Penalty equity return	(q)				4.03%
Incentive equity rate	(r)				11.93%
Revenue under traditional rate making ($)(1)	(i)*(p)+(j)*(q)			25.7	25.1
Revenue under penalty rate ($)(1)	(k)*(q)+(l)*(q)			-	0.4
Incentive equity return on savings ($)(1)	(n)*(r)+(o)*(q)				-
Total				25.7	25.5
Annual savings to customers					0.2
Effective equity return to the Applicant					8.82%

(1) Assumes a period of no cash tax payment and hence no gross-up.

Case 2: Actual capital spent is more than the Bid Amount; the cost of Exceptions are less than the costs included in the Bid Amount for the same.

This case assumes the Project is built at a total cost of $428.4 million (as set out in Table P-14 below), the cost of the Exceptions is $14.0 million and cost overage amount to $20 million. The Applicant's Bid Amount includes estimated costs for Exceptions at $19.0 million.

Under the Applicant's Development and Construction Cost Proposal, the Applicant would seek to include $413.4 million into the rate base for an equity return at the Board's rate determined in accordance with its cost of capital methodology. For the additional expenditures of $15 million for which the risk is assumed by the Applicant, the Applicant would seek to recover a return at only the Board's deemed cost of debt in its rate applications on such amount. This results in annual savings of $0.3m to the ratepayers and leaves the Applicant with an effective return on equity of 8.76 percent only, instead of the allowed 8.93 percent return.

Table P-14		**Case 2 (Higher total spend, lower actual exceptions)**			
($, in millions CAD)		Project bid	Total actual spent	Traditional rate making	Proposed rate making
Total project cost	(a)	413.4	428.4	428.4	428.4
Adjust for					
Exceptions embedded in cost above					
Land acquisition costs		15.5	9.5	9.5	15.5
Environmental and permitting costs		2.5	2.5	2.5	2.5
Aboriginal participation costs		1.0	1.0	1.0	1.0
Line distance greater than 410 km (Actual 411 km)		-	1.0	1.0	1.0
Total exceptions	(b)	19.0	14.0	14.0	20.0
Cost excluding exceptions	(c)=(a)-(b)	394.4	414.4	414.4	408.4
Allowed cost based on bid	(d)			414.4	394.4
Allowed exceptions	(e)			14.0	20.0
Cost overages on bid amount	(f)=(c)-(d)				14.0
Cost savings from bid amount	(g)				0.0
Traditional rate making rate base	(h)=(a)-(f)-(g)			428.4	413.4
Equity (40%)	(i)=(h)*0.4			171.4	165.4
Debt (60%)	(j)=(h)*0.6			257.0	248.0
Penalty return rate base	(f)				15.0
Equity (40%)	(k)=(f)*0.4				6.0
Debt (60%)	(l)=(f)*0.6				9.0
Allowed equity return	(p)			8.93%	8.93%
Allowed debt return	(q)			4.03%	4.03%
Penalty equity return	(q)				4.03%
Incentive equity rate	(r)				11.93%
Revenue under traditional rate making ($)(1)	(i)*(p)+(j)*(q)			25.7	24.8
Revenue under penalty rate ($)(1)	(k)*(q)+(l)*(q)			-	0.6
Incentive equity return on savings ($)(1)	(n)*(r)+(o)*(q)				-
Total				25.7	25.4
Annual savings to customers					0.3
Effective equity return to the Applicant					8.76%

(1) Assumes a period of no cash tax payment and hence no gross-up.

Case 3: Actual capital spent is less than the Bid Amount; the cost of Exceptions are more than the costs included in the Bid Amount for the same.

This case assumes the Project is built at a total cost of $398.4 million (as set out in Table P-15 below). The cost of Exceptions exceeds the costs for the same included in the Bid Amount by $5 million, as such; the actual cost savings are $20 million, not taking into account the increased cost of the Exceptions.

Under the Applicant's Development and Construction Cost Proposal, the Applicant would reduce its rate base by the $20 million of savings and apply for its equity return on such reduced rate base at the Board's rate determined in accordance with its cost of capital methodology. On the $20 million of savings, the Applicant would seek an incentive return on its equity portion of this amount of 300 basis points higher than the Board's rate for a return on equity determined in accordance with its cost of capital methodology. Even in this case, because of the unique bid structure proposed by the Applicant, rate payers annually save $0.7 million compared to a fixed cost bid structure, as demonstrated in Table P-15 below. Though the effective return on equity at 9.08 percent is higher than the customary equity return the Applicant would have earned, there is a strong incentive for the Applicant to manage the costs effectively and complete the Project at a lower cost and therefore bring greater savings to rate payers.

Table P-15		**Case 3 (Lower total spend, higher actual exceptions)**			
($, in millions CAD)		Project bid	Total actual spent	Rate making based on bid	Proposed rate making
Total project cost	(a)	413.4	398.4	413.4	398.4
Adjust for					
Exceptions embedded in cost above					
Land acquisition costs		15.5	19.5	19.5	19.5
Environmental and permitting costs		2.5	2.5	2.5	2.5
Aboriginal participation costs		1.0	1.0	1.0	1.0
Line distance greater than 410 km (Actual 411 km)		-	1.0	1.0	1.0
Total exceptions	(b)	19.0	24.0	24.0	24.0
Cost excluding exceptions	(c)=(a)-(b)	394.4	374.4	389.4	374.4
Allowed cost based on bid	(d)			389.4	394.4
Allowed exceptions	(e)			24.0	24.0
Cost overages on bid amount	(f)				0.0
Cost savings from bid amount	(C)				20.0
Traditional rate making rate base	(d)=(a)-(c			413.4	378.4
Equity (40%)	(e)=(d)*0.4			165.4	151.4
Debt (60%)	(f)=(d)*0.6			248.0	227.0
Incentive return rate base	(g)				20.0
Equity (40%)	(h)=(g)*0.4				8.0
Debt (60%)	(i)=(g)*0.6				12.0
Allowed equity return	(j)			8.93%	8.93%
Allowed debt return	(k)			4.03%	4.03%
Penalty equity return	(l)				4.03%
Incentive equity rate	(m)				11.93%
Revenue under traditional rate making ($)(1)	(e)*(j)+(f)*(k)			24.8	22.7
Revenue under penalty rate ($)(1)				-	-
Incentive equity return on savings ($)(1)	(m)*(j)+(i)*(k)				1.4
Total				24.8	24.1
Annual savings to customers					0.7
Effective equity return to the Applicant					9.08%

(1) Assumes a period of no cash tax payment and hence no gross-up.

Case 4: Actual capital spent is less than the Bid Amount; the cost of Exceptions are less than the costs included in the Bid Amount for the same.

This case assumes the Project is built at a total cost of $398.4 million (as set out in Table P-16 below). The cost of Exceptions is less than the amount for the same included in the Bid Amount by $5 million which estimated the cost for Exceptions at $19.0 million. Total savings are $15 million.

Under the Applicant's Development and Construction Cost Proposal, the Applicant would reduce its rate base by the $15 million of savings and apply for its equity return on such amount at the Board's rate determined in accordance with its cost of capital methodology. On the $15 million of savings, the Applicant would seek an incentive return on its equity portion of this amount of 300 basis points higher than the Board's rate for a return on equity determined in accordance with its cost of capital methodology. Even in this case, because of the unique bid structure proposed by the Applicant, rate payers annually save $0.7 million compared to a fixed cost bid structure, as demonstrated in Table P-16 below. Though the effective return on equity at 9.04 percent is higher than the customary return the Applicant would have earned, there is a strong incentive for the Applicant to manage the costs effectively and complete the Project at a lower cost and therefore bring greater savings to rate payers.

Table P-16		**Case 4 (Lower total spend, lower actual exceptions)**			
($, in millions CAD)		Project bid	Total actual spent	Rate making based on bid	Proposed rate making
Total project cost	(a)	413.4	398.4	413.4	398.4
Adjust for					
Exceptions embedded in cost above					
Land acquisition costs		15.5	9.5	9.5	15.5
Environmental and permitting costs		2.5	2.5	2.5	2.5
Aboriginal participation costs		1.0	1.0	1.0	1.0
Line distance greater than 410 km (Actual 411 km)		-	1.0	1.0	1.0
Total exceptions	(b)	19.0	14.0	14.0	20.0
Cost excluding exceptions	(c)=(a)-(b)	394.4	384.4	399.4	378.4
Allowed cost based on bid	(d)			399.4	394.4
Allowed exceptions	(e)			14.0	20.0
Cost overages on bid amount	(f)				0.0
Cost savings from bid amount	(C)				15.0
Traditional rate making rate base	(d)=(a)-(c			413.4	383.4
Equity (40%)	(e)=(d)*0.4			165.4	153.4
Debt (60%)	(f)=(d)*0.6			248.0	230.0
Incentive return rate base	(g)				15.0
Equity (40%)	(h)=(g)*0.4				6.0
Debt (60%)	(i)=(g)*0.6				9.0
Allowed equity return	(j)			8.93%	8.93%
Allowed debt return	(k)			4.03%	4.03%
Penalty equity return	(l)				4.03%
Incentive equity rate	(m)				11.93%
Revenue under traditional rate making ($)(1)	(e)*(j)+(f)*(k)			24.8	23.0
Revenue under penalty rate ($)(1)				-	-
Incentive equity return on savings ($)(1)	(m)*(j)+(i)*(k)				1.1
Total				24.8	24.0
Annual savings to customers					0.7
Effective equity return to the Applicant					9.04%

(1) Assumes a period of no cash tax payment and hence no gross-up.