Response to the Peer Review Report
EPA Base Case Version 5.13 Using IPM

U.S. EPA, Clean Air Markets Division

SECTION 1
INTRODUCTION

In October 2014, the U.S. Environmental Protection Agency (EPA) commissioned a peer review of the EPA Base Case version 5.13 using the Integrated Planning Model (IPM).[1] RTI International, an independent contractor, facilitated the peer review of the EPA Base Case v.5.13 in compliance with EPA's *Peer Review Handbook* (U.S. EPA, 2006) and produced a report from that peer review. RTI selected five peer reviewers (Anthony Paul, Meghan McGuinness, Walter Short, Paul Sotkiewicz, and John Weyant) who have expertise in energy policy, power sector modeling and economics to review the EPA Base Case v.5.13 and provide feedback. The peer reviewers evaluated the adequacy of the framework, assumptions, and supporting data used in the EPA Base Case v.5.13 using IPM, and they suggested potential improvements.

IPM is a multiregional, dynamic, deterministic model of the U.S. power sector that provides forecasts of least-cost capacity expansion, electricity dispatch and emission reliability constraints. The EPA uses the platform to project and evaluate the cost and emissions impacts of various policies to limit emissions of sulfur dioxide, nitrogen oxides, particulate matter, mercury, hydrogen chloride, and carbon dioxide (CO_2).

The independent peer review panel provided expert feedback on whether the analytical framework, assumptions and applications of data in the EPA's Base Case v.5.13 using IPM are sufficient for the EPA's needs in estimating the economic and emissions impacts associated with the power sector due to emissions policy alternatives.

The panel identified a number of strengths associated with the model. For example, the report stated that model exceeds other model capabilities in providing a relevant feedback mechanism between the electric power model and key fuel inputs that drive simulation results.

Other strengths the panel identified include:
- The detail with which pollution control technology options and costs are represented
- The level of detail at which federal Clean Air Act (CAA) regulations are represented
- The ability of the model to allow for the detailed representation of a variety of potential changes in energy and environmental policies, including complicated features of market-based programs

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[1] Documentation and files for EPA Base Case version 5.13 using IPM are located at http://www2.epa.gov/airmarkets/power-sector-modeling-platform-v513

- The accuracy of the emissions control costs and their relationship to retirement decisions
- The expansion of model regions from 32 to 64, which allows the model to better represent current power market operations and existing transmission bottlenecks even within regional transport organization (RTO) regions
- Continuous updates of the representation of domestic coal and natural gas market conditions.

The peer review panel has also provided several areas for investigation and additional recommendations for the EPA's consideration, including:

- Input assumption documentation, which we discuss and respond to in Section 2 of this document.
- Particular elements of the EPA Base Case version 5.13 modeling structure that we discuss and respond to in section 3 of this document.

Since the peer review was completed, there have been two subsequent versions of the EPA Base Case's (version 5.14 and 5.15)[2] Some of the peer review comments regarding documentation have already been addressed through these incremental documentations. The two incremental documentation reports are supplemental to the comprehensive EPA Base Case v.5.13 documentation report, and are available at the EPA Power Sector Modeling Website.[3] The first incremental documentation report covers changes made in the 2014 update to IPM (v.5.14) base case, and the second incremental report covers changes made to the 2015 update (v.5.15) base case. The EPA anticipates when the next version of base case is completed, the EPA will prepare a comprehensive documentation report analogous to the EPA Base Case v.5.13 documentation.

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[2] Available at http://www.epa.gov/airmarkets/power-sector-modeling.

[3] Available at http://www.epa.gov/airmarkets/power-sector-modeling

SECTION 2
INPUT ASSUMPTION DOCUMENTATION

2.1 VOM/FOM Cost Documentation

The Peer Review Report stated that the IPM documentation is a great source of data and information ranging from capital costs to Variable Operations and Maintenance (VOM) and Fixed Operations and Maintenance (FOM) costs, heat rates, and the cost and performance characteristics of emissions controls among other items. However, it was stated that while some information is well documented (e.g., emissions control from Sargent & Lundy), others are not.

In order to provide more detailed explanation of the VOM and FOM costs, we have made documentation enhancements in the subsequent EPA Base Case using IPM version 5.14 documentation[4] and retained this information in the EPA Base Case using IPM version 5.15.

The panel also suggested increasing FOM costs with age over the modeling time horizon. The FOM costs for coal steam and oil/gas steam units in the EPA Base Case v.5.13 are age-specific. The cost is applied to a model plant based on its age at the start of the modeling time horizon, and remains constant through the modeling time frame. Most existing fossil/steam units also have the option in the model to incur an assumed representative life extension cost (as an addition to the constant annual FOM cost), which varies by plant type and is applied at the unit age corresponding to an assumed representative design life for that plant type. The EPA will consider revising this approach in a future platform to allow the initially assumed FOM cost to adjust with a unit's age over the modeling time horizon.

2.2 Financial Assumptions

The panel noted a number of areas in the Financial Assumptions (Section 8) of the EPA Base Case v.5.13 documentation where assumptions are inadequately documented or their application insufficiently explained. The peer reviewers suggested that the EPA comb through the full documentation to identify and address assumptions that do not cite original sources with sufficient specificity, and to identify areas where more explanation is needed about how the assumption is applied in the model. In response to these comments, the EPA will take several steps for the documentation of the next major update of the financial assumptions:

- Ensuring all footnotes refer to primary sources and include a current web address, if possible.
- Enhancing the documentation by expanding key sections to include relevant background independent of modeling context, a full explanation for why the EPA selected a certain parameter or value, and a brief discussion for how that parameter interacts with the modeling framework.

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[4] Section 4.2.7 of Base Case version 5.14 Incremental Documentation at http://www2.epa.gov/airmarkets/power-sector-modeling-platform-v514)

- Sequence the documentation such that key assumptions are fully detailed when they are first introduced to prevent the need for readers to search through multiple sections of the documentation to understand a single concept.
- Explaining the relevance of documented financing structures to how the IPM modeling framework determines solutions.

Further, the panel requested the EPA identify assumptions that differ from generally accepted values or those used by other well-known entities (especially other government entities), why the choice of a different assumption was made, and the potential implications of this choice for policy analysis. The EPA is unaware of any assumptions that differ from generally accepted values and the panel provided no concrete examples of such an occurrence. Financial assumptions that require a numerical value are assigned historical values, historical average values, or are based on current values that the EPA assumes will revert, at least directionally, to longer-term averages that are more suitable to IPM's intended purpose of projecting fundamentals-based capital investment decisions in the medium- to long-term. One example of such an assumption is return on equity. The EPA assumes that return on equity values will trend modestly upwards over time from the current, historically low values. This assumption is informed by the EPA's desire not to enshrine the current returns on equity for all future time periods, while recognizing that it is unclear when – or if – a return to higher rates more consistent with longer-term historical averages will occur. Increasing the return on equity over time in a modest fashion is intended to reflect a cautious approach appropriate for modeling tools such as IPM. The approach of incrementally higher returns on equity over time is also adopted in the EIA's financial assumptions for the Electricity Market Module. The EPA understands that the use of historical data requires constant evaluation to validate its appropriateness both as a stand-alone value as well as how that value is integrated with other financial assumptions. The EPA will consider additional analysis to inform the choice of financial assumptions in the next version of the model and its documentation.

2.2.1 Social Cost-Minimizing

The peer review panel stated that:

> It is not clear that the social cost–minimizing solution supports a competitive equilibrium in wholesale power markets (with either energy and capacity markets or energy-only markets) or traditionally regulated regimes. The documentation at minimum linking the "shadow prices" that come out of the linear programming (LP) framework with actual prices paid to generation, or available to be collected by generation, either in competitive wholesale markets or in traditional cost-of-service regimes would be helpful to understand IPM results. Another way of phrasing this would be to check that under the shadow prices computed by IPM, entry, exit and

> retention decisions are “individually rational” such that at these prices, resources would do exactly the same thing IPM is saying will happen in the social cost minimum. (Peer Review Report, page 4-5)

The IPM approach of minimizing the cost can be viewed from a social cost perspective, but it can also be viewed as a competitive equilibrium in power market investment and operation. IPM assumes that entities offer their supply to the wholesale market at cost, know the cost of other offers in the markets and act as if other bidders in the market had the same knowledge and behaved in the same way. Although the IPM solution technique is linear optimization, the modeling framework can be regarded as a planner’s perspective, as it models the market as if a planner were deciding how to offer supply from a plant into a marketplace, such as might be found in a RTO. Operating in this way, IPM ensures that there is consistency between the model operations and the resulting marginal costs (“shadow prices”). IPM operation is consistent with the following view of an efficient planning process:

- The output of each generating plant is assumed to be offered into the market for dispatch at the short run variable cost, consisting primarily of fuel and variable operating and maintenance costs.[5]
- The market is cleared based on offers from all plant operators by minimizing the wholesale delivered cost to meet load in each future time period and region, subject to the constraints such as transmission and environmental limits.[6] The result of the simulated dispatch is a marginal price for energy and capacity in each future time period, analogous to the short-term pricing structure of an RTO with markets for energy and capacity, or a competitive wholesale market outside an RTO.
- The expected prices in future time period form the forward price series a planner would use to determine whether the existing plant should be retained in the fleet, retrofitted to meet environmental requirements, or retired, and whether new generating capacity will be required to meet demand in one or more future periods. The model assumes perfect foresight in the sense that it assumes the future prices are known at the outset of the planning horizon. The overall optimization determines the price as the shadow price on the appropriate constraints (demand for the energy price and reserve constraints for the capacity price.)[7]
- IPM solves for the combined effect of the short run dispatch results in each period and the longer run planning choices simultaneously, assuming that short run markets work efficiently, and that planners successfully aim at efficient, least cost decisions in the long term using these prices. Any alterations in short run offers will influence capacity planning decisions, and vice versa, so that IPM’s marginal prices in each time period are consistent with the entry and exit of generating capacity, as well as with choices about which plants to retrofit.

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[5] The main components of these steps are noted in the IPM documentation. See IPM documentation Chapter 2.2.2 on Generation Dispatch Variables.

[6] This result is the short term effect of the overall IPM optimization described in Chapter 2 of the IPM documentation.

[7] See IPM documentation Chapter 2.2.3 on Demand and Reserve Constraints

IPM attempts to reflect the important parameters of the dispatch and planning functions, and multi-period optimization does so in a way that ensures consistency among prices, dispatch quantities and entry and exit of generating capacity. As a result, IPM projected prices are consistent with competitive operation of wholesale markets.

2.2.2 Financial Regions

The peer review panel stated that:

> The current financial modeling assumptions seem to apply across the country and may not be relevant in some organized ISO/RTO wholesale power markets and should be differentiated by area. For example, in PJM, much of the new entry taking place across the footprint is merchant only, while in some zones (e.g., Dominion) it is a vertically integrated entry for the most part (Peer Review Report, page 4-17).

In the development of the EPA Base Case, the EPA considered an approach that would categorize areas in the United States as one of two types of financial regions – traditional cost-of-service and competitive. Under this approach, cost-of-service regions would be assigned capital charge rates based on regulated utility financial assumptions and competitive regions would be assigned capital charge rates based on merchant financial assumptions.

However, such a modeling approach could result in overbuilding in the cost-of-service region (due to relatively lower capital charge rates) that does not take into account real-world regulatory prohibitions of external sales. In practice, there are formal and informal limits constraining new capacity development that are difficult to capture in modeling simulations. For example, recent proposals in PJM explicitly limit capacity expansion by some entities to be such that the total capacity does not exceed internal requirements.[8]

Even if such new capacity deployment limitations could be implemented in the model, the model would still face mixed regions in which there are both deregulated and regulated power plants and participants, which calls into question the categorical assignment of merchant or utility financial assumptions to the entire region. Recognizing the complexity of interregional electricity trade and new capacity development under both merchant and utility financing conditions, the EPA Base Case v.5.13 uses a hybrid approach to capture as many of these variables as possible without introducing modeling artifacts favoring new capacity development in any particular region.

2.2.3 Financial Assumptions Appropriate for Longer Term Projections

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[8] https://pjm.com/~/media/committees-groups/committees/mrc/20121017/20121017-proposed-mopr-summary.ashx

The peer review panel stated that:

> The financing assumptions based on 2008–2012 require major reworking as this includes the effect of the worst financial crisis since the Great Depression, and current financial markets world-wide are showing much lower returns on debt and equity. To say the current levels are “unsustainable” or “artificial” is irresponsible and does not reflect experience in Japan, where they are two decades into a similar crisis and still have lower capital costs as a result (Peer Review Report, page 4-17).

In the EPA Base Case, financing costs are expected to increase over time. The mechanism for expressing this increase is applying a higher risk free rate for the cost of capital. The five-year average risk free rate (3.8 percent) is used to inform the ROE rather than the current rate (2.5 percent). It is appropriate to use a five-year average to establish the risk free rate for a number of reasons:

- Current rates are historically low due to the slow pace of recovery from the most recent recession.
- The EPA base case financial assumptions are changed infrequently, and hence, it should not use assumptions reflective of a single point in time.
- Merchant and utility cost of debt, debt-equity ratios, and historical betas are all calculated based on the last 5 years (2008-2012) of historical data. The same approach to calculate the risk free rate is used in order to remain consistent in its methodology.

Low interest rates may continue for some time; however, since investments in IPM are based on expectations for long-term periods of up to 20 years and longer, it is still reasonable to expect financing costs to return to longer-term trends. This is supported by multiple statements by the Federal Reserve that they intend to raise rates from recent levels, and that they do not intend to continue monetary policies adopted in the wake of the financial crisis indefinitely. Both historical rates and current expectations are reevaluated for each new version of IPM.

SECTION 3
Model Structure and Capabilities

We have identified several main topic areas that peer reviewers commented on that are relevant to modeling structure and capability: 1) model design, 2) demand, 3) transmission, and 4) renewables.

The responses provided in this section explain where it is possible to conduct further research and to make subsequent improvements in our modeling to address them. We would embark in such an effort if we assess that these additional capabilities would significantly improve our modeling capabilities (especially in the context of environmental policies evaluated) without compromising other aspects of the modeling capabilities (such as model size and run-time) with the available resources and timelines.[9] Therefore, this section intends to clarify the areas where it is possible to improve or modify our modeling structure and capabilities pursuant to our analytical goals.

3.1 Model Design

The peer review panel recommended "consideration of the addition of one more season—the shoulder season—to differentiate the spring and fall with respect to load duration curves (LDC)" (Peer Review Report, page 3-2). In IPM, the seasonal and segmental definition of load duration curves characterizes the resolution of demand modeling. All else held equal, an increase in the number of seasons and/or segments could be expected to improve power plant dispatch modeling. However, in model development, all else cannot be held equal; we must make trade-off decisions in model design in order to maintain viable model size and acceptable run-time conditions. Since the model size is directly proportional to number of seasons and segments, base case design must consider the analytic merits of different seasonal definitions alongside analytic merits of different numbers of run years, retrofit options and model plants represented in the modeling framework. The EPA will explore alternate seasonal and segmental definitions, including options that represent a "shoulder season," in the development of future base cases.

The peer review report also stated:

> In constructing the LDCs for the two seasons modeled by IPM, a single year of data (2011) was employed. The data are hourly load data in each IPM model region. A more robust approach would take an average over multiple years of data, thereby generating a more realistic projection than that from a single year of data. The panel understands that the justification for using a single year instead of an average over multiple years is to synchronize with the treatment of time in the atmospheric transport models that EPA sometimes uses in conjunction with IPM. The panel recommends

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[9] The peer reviewers recognized that the model necessarily includes simplifications, in part because of the need to maintain reasonable run times so that the model can be used for policy-relevant analysis on a timely basis. Peer Review Report, page 4-1.

> that the multiyear approach be adopted across the board. (Peer Review Report, page 4-16)

In IPM, the hourly load curves define the load duration curves and hence can affect power plant dispatch. In general, weather normalized load curves are constructed and used in models instead of the load curves of a historical year. Past weather data can also be analyzed to pick a year with normal weather for a region and then to use that year's load curve for that region. The EPA has used the 2011 load curves for the entire country to be consistent with the EPA's treatment of temporal distribution in air quality models. The EPA will explore this issue further in the future in conjunction with other considerations informing the EPA's selection of historical data to inform air quality modeling and benefits analyses.

3.2 Demand

The peer review report stated:

> It seems odd to have fixed electricity demands drive the solution of the IPM linear program base case as changes in demand that occur in response to changes in economic and noneconomic conditions over time seem like some of the most important adjustments that would take place in both base case and policy projections. The fixed demands for the IPM base case seem to also come from the NEMS model, which raises the question of consistency between the costs and prices in the NEMS model and in IPM. If the upstream cost/price results from IPM are different than those from NEMS for the scenario used to generate the NEMS demands that are then fixed in IPM, this seems like a large potential inconsistency in the baseline, which could be even more significant in any policy case run from that baseline. One solution would be to estimate demand curves (demand vs. price functions) with NEMS that are then incorporated into IPM. This would insure both the internal consistency of the supply/demand/price picture coming out of IPM and its suitability for considering policy alternatives. (Peer Review Report, page 4-7)

There are two issues raised here by the peer review panel. The first concerns the appropriateness of using a fixed demand projection. While we believe the current approach is reasonable, for our next modeling platform we will explore if and how we should develop elasticities from comparing Annual Energy Outlook (AEO) reference and alternative cases to support demand representation within IPM in a more flexible way, along the lines suggested by the peer reviewers. We believe the current representation is reasonable both because it reflects changes in exogenous economic and noneconomic conditions over time (a fixed demand approach should not be construed as one that relies exclusively on historical or current conditions), and because the price fluctuations observed in the base case (the subject of this peer review) do not have a significant impact on overall demand and therefore do not warrant such a capability. The second concern is that adopting demand projections from NEMS when there are cost and price differences between NEMS[10] and IPM might represent a significant inconsistency. However, available data even across NEMS scenarios (where costs and prices may vary substantially, but within the same model, which is also considering electricity demand endogenously) do not bear this concern out. As an illustrative example, in the 2015 AEO there is only a 0.1% difference in the average annual growth rate of demand when comparing the Reference Case with the high and low oil and gas resource cases. This minor difference in demand relative to a significant change in fuel prices illustrate why demand projections in the EPA Base Case using IPM do not have to share identical cost and price inputs with a given NEMS scenario to be internally consistent; rather, the demand projection simply has to contain cost and price inputs that do not necessitate unreasonable assumptions among the many broader macroeconomic conditions or trends that are not endogenously adjusted in IPM. Many of the cost and price inputs endogenously determined by IPM can be shown to have a negligible impact on overall demand levels, especially when compared with these broader macroeconomic conditions or trends.

The peer review report also stated:

> The current model in use by EPA does not allow for the endogenous determination of energy efficiency options or demand response in dispatch. These two options have become key parts of wholesale power markets and in integrated resource plans executed by vertically integrated utilities, but are always evaluated implicitly or explicitly based on the economics. (Peer Review Report, page 4-6)

EPA Base Case v.5.13 does not model energy efficiency (EE) or demand response (DR) options endogenously. For the next platform, we will evaluate whether adequate data are available to model EE or DR options as “negawatt generators” that could capture seasonal load shape impacts and costs of each EE or DR measure at a regional level.

3.3 Transmission

The peer review report states:

> While the IPM model is a pipes-and-bubbles model between the 64 regions, there are transmission constraints within each of the 64 model regions, and generator deactivations may create the need to build a great deal of transmission to allow units to retire in a reliable manner. One suggestion is for EPA to examine the use of internal regional transmission constraints to get a better sense of the constraints on dispatch. The second suggestion to account for transmission costs (and/or reliability-must-run [RMR] generator costs) associated with generator retirements, is to estimate the “average” cost of new transmission and RMR associated with retirements to account

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[10] NEMS is the Energy Information Model used for the AEO projections.

> for these costs in the baseline and in policy cases… Because of the way the grid works, some non-linearities can be represented in [a pipes-and-bubbles model] and some transmission studies have informed the pipe and bubbles constraints, but the model is still limited because of its underlying formulation being pipe and bubbles which precludes consideration of point to point transmission that would better represent the actual operation of the current and future electricity grid. Additional resolution in transmission capacity should be considered. (Peer Review Report, pages 4-16 to 4-17)

The IPM Base Case v.5.13 does include transmission costs for wind units within regions, by reflecting the cost of transmission in the wind unit cost classes. In the next platform, we will consider whether/how the number of model regions in the EPA Base Case using IPM could be increased to capture additional intra-zonal constraints that are not addressed explicitly in the EPA Base Case v.5.13 (and in the existing subsequent versions so far), by reviewing current market information for each region and comparing to the existing configuration of zones/regions in IPM to determine if there are any major intra-zonal constraints, load pockets or generation pockets that are not modeled explicitly. For any such identified areas, we could define sub-zones in IPM as new regions and determine that area’s interregional transfer capabilities using any available information. We will also review market information for each region to determine whether we can estimate, and potentially incorporate, a generic transmission reliability-related retirement cost based on any identified historical cost of transmission improvements required to enable retirements in the region.

3.4 Renewables

The peer review report stated:

> The wind capacity values in ***Tables 4-21*** through ***4-23*** in the IPM documentation are reasonable for the initial wind installed into a utility system. However,... the capacity value of wind declines as more wind is added to a utility system. The decline will be more rapid if all of the wind capacity is installed at the same location because if the wind is not blowing at that location when a generator or transmission line fails during a peak load time, adding more capacity will not increase the contribution to the reserve margin requirement. However,… were the next increment of additional wind located at a different site, there is a better chance that wind will be available from at least one of the sites (i.e., with geographic diversity, the wind sites will have a higher overall capacity value). Geographically diverse wind sites can also reduce curtailments and the need for spinning reserves. IPM’s wind capacity values do not account for either the level of wind penetration or the geographic diversity of the wind sites selected. (Peer Review Report, page 4-9)

Solar and wind technologies are intermittent and not dispatchable. Hence, the generation from these technologies may not be available during system peak. IPM accounts for this issue by reducing the reserve margin contribution for these technologies based on results from other studies. In the EPA Base Case v.5.13 (and in the subsequent existing versions so far), these reserve margin contribution factors remain constant over the time horizon. However, as pointed out by the peer reviewers, these factors do not remain constant, but reduce with increased renewable penetration in a region. To address this concern, the EPA chose to impose IPM region-specific deployment constraints that limit new builds to levels for which it is unnecessary to further reduce the reserve margin contribution of these potential build options, in order to accurately represent the generation available from wind units at the system peak. We will continue to evaluate this issue when developing the next modeling platform.

The peer review report also states:

> If wind or solar generation increases unexpectedly, it may not be possible to ramp down conventional generators fast enough or low enough to accommodate the renewable energy. In this case, the renewable energy cannot be used. Such curtailments of wind and solar will not be significant until the fraction of load met by wind and solar is significantly higher than it is today (today's curtailments of wind and solar are due mostly to transmission limitations). However, in modeling climate change or high natural gas prices, penetration of wind and solar may climb to levels where the unused VRRET[11] energy due to ramping constraints significantly impacts the overall economic viability of these VRRETs. Since IPM makes no estimate of the curtailments from wind and solar, it again inappropriately advantages VRRETs. This IPM limitation may be largely removable by adding a step-wise linear function that accounts for curtailments by reducing the output of VRRETs as more VRRET capacity is installed in a utility system. (Peer Review Report, page 4-8)

The EPA addresses this concern in the current platform through IPM region-specific deployment limits. There is no estimate of curtailment in the current base case because new capacity is limited to levels that have been demonstrated successfully without the need for significant curtailment in the EPA Base Case v.5.13 (and in the subsequent existing versions so far) or in policy cases related to these base cases. However, the model may choose not to utilize (i.e., to 'dump') excess energy from VRRETs during periods of low demand as part of a least-cost solution. This 'dumped' energy is displayed in the standard IPM outputs. We will continue to evaluate this issue when developing the next platform.

The peer review report also states:

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[11] The Peer Review report defines the term VRRET as variable resource renewable energy technology.

> Spinning reserves are usually conventional generators that are operating, but at less than their full capacity. As such, they can be quickly brought up to full capacity should the system require additional power. Because the generation from wind and solar can drop unexpectedly, generation from these technologies must be backed up by spinning reserves. Since IPM does not account for spinning reserves, wind and solar are given an inappropriate advantage in IPM. This advantage may be fairly easy to correct in IPM by adding a spinning reserve constraint in which the contribution from operating dispatchable rotating generators contributes positively toward meeting the constraint, and the addition of VRRETs contributes negatively. (Peer Review Report, page 4-8)

The EPA Base Case using IPM v5.13 includes explicit reserve margin constraints, a partial reserve margin contribution for intermittent technologies, capacity deployment limits for intermittent technologies, and various operational constraints related to the operation of fossil fuel-fired capacity; given this modeling context and the level of intermittent RE generation in the EPA Base Case using IPM v5.13, a constraint related specifically to establishing a minimum level of spinning reserves would be redundant. However, in the next platform, we will continue to evaluate if and how the effect of increasing RE penetration on demand for spinning reserves should be captured more directly in the model.

The peer review report also states:

> Because integration requirements become more difficult as more VRRETs are added to a utility system, the penetration of VRRETs is naturally limited in the real world. Since IPM does not capture this increasing integration difficulty, it is forced to use a surrogate method for limiting the penetration of VRRETs. For wind, this is at least partially effected by adopting the wind cost classes and their corresponding capital cost multipliers from EIA's NEMS model. As shown in Table 4-24 of the IPM documentation, IPM's wind capital cost multipliers range in value from 1.0 to 2.0. The IPM documentation quotes NEMS documentation to the effect that these multipliers account for "such factors as distance from existing transmission, terrain variability, slope and other causes of resource degradation, site accessibility challenges, population proximity, competing land uses, aesthetics, and environmental factors." These are real factors that do need to be accounted for. However, as shown in Table 4-17 in the IPM documentation, over 90% of the wind resource is included in cost class 5, which doubles the capital cost of wind. This is an unrealistically large cost increase that is not evident in practice. In NEMS, and the panel suspects in IPM, this doubling of the cost of wind for 90% of the wind sites precludes wind from capturing a significant share of the electric power market. (Peer Review Report, pages 4-12 to 4-13)

IPM's cost projections for deployment of wind resources are related to transmission availability and other factors at the sites where the wind resources are found; IPM cost classes and resources make clear that there are ample opportunities for deployment of cost-effective wind resources. IPM cost classes reflect the fact that the vast majority of the wind resource in this country is located in areas that are not amenable to development, but also show that there remain ample opportunities for deployment of wind projects. Both of these facts are accurately reflected in the EPA Base Case using IPM v5.13 using wind resources and cost classes. The total onshore potential wind capacity resource included in the EPA Base Case using IPM v5.13 is vast. For example, the resource available under cost step 1 far exceeds the amount of wind that is deployed in the EPA Base Case using IPM v5.13, despite being only a few percentage points of the total wind resource. The resource specified cumulatively under cost steps 1-3 (cost multiplier of 1 to 1.25 times the base cost) is many times greater, meaning there are huge amounts of wind resources under the lowest wind classes that are not being deployed in the model; thus the costs of concern to the reviewers are not constraining the deployment of wind in the IPM base case. In the next platform we will continue to evaluate the wind resource assigned to each cost step to ensure an appropriate representation of the availability and competitiveness of wind technologies.

The peer review report also states:

> IPM constrains the annual generation from wind to be no more than 20% of the annual generation in each region. This artificial limit has already been exceeded in Iowa, where over 27% of the 2013 electric load was met by wind energy (U.S. EIA, 2014). The constraint is even more egregious in states/regions like Wyoming and North Dakota that have substantial wind resources that could be used to generate wind power for export to nearby regions with larger populations and loads; clearly, this 20% limit would preclude much of this potential export capability. The peer review panel recommends that this 20% constraint on wind generation be removed from IPM. (Peer Review Report, page 4-13)

The annual wind generation constraint by IPM region does not represent a technical limit, but rather a constraint representing wind penetration levels that could be projected by the model without requiring significant integration costs not explicitly represented in this platform. For regions that currently exceed this limit, the limit has been adjusted upward to reflect local conditions. In the next platform we will continue to evaluate alternatives to this constraint to ensure all appropriate costs are accounted for under higher penetration scenarios.

The peer review report also states:

> Solar thermal power can take advantage of thermal storage of the working fluid to generate power at a later time. The IPM documentation does not say explicitly whether it considers this option, but the solar thermal generation profile presented in ***Table 4-28*** of the IPM documentation suggests that no thermal storage is assumed by IPM. This needs to be corrected as the primary reason for adopting solar thermal electric generation capacity is its ability to store energy for dispatch at a later time…

> Electric power storage technologies can mitigate the variability of wind and solar power. While the IPM documentation mentions that pumped storage is modeled, details are not provided. New pumped storage and compressed air energy storage should be considered in IPM. Because of their ability to ramp up and down quickly, reservoir-based hydroelectric facilities can also mitigate the variability of wind and solar power. (Peer Review Report, pages 4-11 to 4-12)

The EPA Base Case v.5.13 (and the existing subsequent versions so far) accounts for new solar thermal options without storage. In the next platform, we will clarify the operation of pumped storage in the IPM documentation, consider representation of energy storage technology options in IPM, and include details about any such options in modeling documentation.

3.5 Heat Rate Improvements

The peer review report stated:

> The IPM Base Case v5.13 includes no provision for endogenous investment in heat rate improvements (HRIs) at coal boilers. However, the version of IPM used in the analysis that supports the Clean Power Plan does allow for coal boilers to invest in a 6% HRI at a cost. This inconsistent treatment of HRI between the base case and the Clean Power Plan scenarios is clearly not appropriate. The panel understands that this resulted from the recent development of the HRI capability that was not available when the base case was run. Future base cases should include the endogenous HRI option. (Peer Review Report, page 4-19)

The RIA modeling supporting the Clean Power Plan offers coal steam model plants a heat rate improvement option that is fully integrated into the IPM modeling framework. This capability enables IPM to solve for the optimal deployment of heat rate improvement (HRI) technologies on a plant-by-plant basis in the regulatory scenarios analyzed. The option for heat rate improvement is only made available in the illustrative plan approaches during the compliance period, in response to the final rule. The intent of this analysis was to examine the impacts of the regulatory scenarios analyzed. As such, EPA believes that it is appropriate to limit heat rate improvement opportunities to the policy case. This approach isolates the impacts of only those improvements that are expected to occur in response to the policy. Going forward, we will continue to consider what heat rate performance is reasonable to expect based on the scenario being analyzed, keeping in mind that in practice, EGU operators have not availed themselves of heat rate improvement opportunities that already appear economic.

RTI Project Number
0213796.001.004

Integrated Planning Model (IPM) Base Case Version 5.13 Peer Review

Peer Review Report

October 2014

Prepared for

U.S. Environmental Protection Agency
Clean Air Markets Division
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LIST OF ACRONYMS

AEO	Annual Energy Outlook
C&I	commercial and industrial
CAA	Clean Air Act
CAMD	Clean Air Markets Division
COI	conflict of interest
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FOM	fixed operation and maintenance
HRI	heat rate improvement
IGCC	integrated gasification combined cycle
IPM	Integrated Planning Model
ISO	independent system operator
LDC	load duration curves
LP	linear programming
MATS	Mercury and Air Toxics Standards
NEEDS	National Electric Energy Data System
NEMS	National Energy Modeling System
NREL	National Renewable Energy Laboratory
OAR	Office of Air and Radiation
PERI	Princeton Energy Resources International
PV	photovoltaics
ReEDS	Regional Energy Deployment System
RMR	reliability must run
RPS	renewable portfolio standard
RTO	regional transmission organization
VOM	variable operating and maintenance
VRRET	variable resource renewable energy technology
WACC	weighted average cost of capital

SECTION 1
INTRODUCTION

The Clean Air Markets Division (CAMD) within the U.S. Environmental Protection Agency's (EPA's) Office of Air and Radiation (OAR) has requested a peer review of Base Case v5.13 of the Integrated Planning Model (IPM), a multiregional, dynamic, deterministic model of the U.S. power sector that provides forecasts of least-cost capacity expansion, electricity dispatch and emission reliability constraints. CAMD uses IPM Base Case v5.13 to project and evaluate the cost and emissions impacts of alternative policies to limit emissions of sulfur dioxide, nitrogen oxides particulate matter, mercury, hydrogen chloride and other toxic air pollutants as well as emissions of carbon dioxide (CO_2) and other greenhouse gases over a modeling time horizon of 2016–2050 to carry out its mission and to support periodic policy and regulatory analyses of the electric power sector.

RTI International (RTI), an independent contractor, supported CAMD by facilitating a peer review of Base Case v5.13 in compliance with EPA's *Peer Review Handbook* (U.S. EPA, 2006). The peer review was conducted to ensure that the power sector model meets EPA's goals for transparency of EPA technical analyses by making it easy for stakeholders and expert reviewers to examine specific estimated impacts of potential new policies, to evaluate the technical credibility of EPA's projections, and to comment on the consequences of modeled policies. RTI selected four peer reviewers and one peer review panel chair who are experts in energy policy, power sector modeling and economics to review Base Case v5.13 and provide feedback. Results of the peer review are intended to evaluate the adequacy of the framework, evaluate assumptions and supporting data used in Base Case v5.13, and identify potential modifications to improve CAMD's forecasting ability.

This report includes a description of the peer review process, the peer review panel report and EPA's responses to the peer review panel report. In addition, all materials provided to the peer reviewers to support the review, such as the panel charge and the technical work product, as well as peer reviewer resumes and a conflict-of-interest (COI) disclosure form, are provided in the appendices.

SECTION 2
PEER REVIEW PROCESS

In February 2014, EPA requested that RTI facilitate a peer review of Base Case v5.13, used by CAMD within EPA's OAR to support policy and regulatory analyses of the electric power sector. RTI managed the peer review independently and according to guidelines in EPA's *Peer Review Handbook* (U.S. EPA, 2006). RTI initiated the process of identifying and selecting five peer reviewers in April 2014 and completed the process in June 2014.

RTI surveyed the literature and on-line resources and gathered recommendations from individuals knowledgeable of the subject matter in order to identify qualified candidates for consideration. Qualified candidates were those with knowledge of the workings of Base Case v5.13 and expertise in power sector forecasting. Of the 21 identified candidates, 4 were excluded from consideration because they or their significant other were involved in the development of ICF International's IPM, EPA's Base Case, or direct competitors of the model, and there was considered to be an inherent COI.

Per instructions from EPA, RTI aimed to select four or five reviewers from the candidate pool based on all of the following criteria:

- expertise, knowledge and experience of each individual
- adherence to the COI guidance in the EPA's *Peer Review Handbook* (2006)
- panel balance with respect to the expertise required to conduct the review and the diversity of relevant scientific and technical perspectives

Five candidates were then highlighted based on recommendations from subject matter experts and those with relevant expertise. In addition, a panel composed of these five candidates was identified as balanced, independent and expert with various backgrounds from academia, nongovernmental organizations, and private consulting.

The five highlighted candidates were then contacted to ascertain their availability and potential COI. Each candidate completed a COI disclosure form to identify any and all real or perceived COI or bias, including funding sources, employment, public statements and other areas of potential conflict in accordance with EPA's *Peer Review Handbook* (U.S. EPA, 2006). A template of the COI form completed by the candidates is included in Appendix A. RTI staff supporting the peer review also underwent a COI investigation to corroborate the independence and a lack of bias across all components of the peer review.

Based on the candidates' availability and qualifications, the information provided in the completed COI disclosure forms, and an independent COI investigation conducted by RTI staff, RTI selected the following five candidates:

- Meghan McGuinness, Bipartisan Policy Center
- Anthony Paul, Resources for the Future
- Walter Short, retired National Renewable Energy Laboratory (NREL)
- Paul Sotkiewicz, PhD, PJM Interconnection
- John Weyant, PhD, Stanford University

Two of the selected peer reviewers, Mr. Paul and Mr. Short, reported no COI on the disclosure form. Dr. Sotkiewicz reported that he attended a CAMD workshop in May 2013 reviewing IPM modeling efforts conducted for the Mercury and Air Toxics Standards (MATS) and Cross-State Air Pollution Rule (CSAPR), that he has participated in panel discussions about the transmission and generation constraints of IPM, and that he works for a bulk power entity. Dr. Sotkiewicz further stated that although he will be leading PJM's efforts to comment on the Clean Power Plan, he has no financial interests that would be affected by IPM Base Case v5.13 modeling results. Ms. McGuinness reported that she worked at EPA CAMD from 2003 to 2006, and currently works with a private-sector version of ICF's IPM. Dr. Weyant reported that he maintains an active grant with the Climate Economics division of EPA conducting model comparisons, and that he participated in a three-person review of IPM for ICF in 2008.

None of the reported COI was deemed inconsistent with EPA's *Peer Review Handbook* (2006). EPA reviewed and approved the list of candidates selected by RTI as appropriate choices from the candidate pool to form an independent and balanced panel. Based on expertise, availability and further recommendations, Mr. Paul was invited to serve as the chair of the peer review panel. Copies of the selected candidate resumes are included in Appendix B of this report.

RTI staff provided the peer reviewers with the following materials to guide the evaluations:

- *EPA-developed Peer Review Charge* (see Appendix C)
- *Documentation for EPA Base Case v.5.13: Using the Integrated Planning Model* (U.S. EPA, 2013)

The peer review panel met several times by conference call and attended one in-person meeting over the following months, submitting the final peer review panel report in October 2014. A summary of the peer review panel meetings is provided in ***Table 2-1***.

Table 2-1. Summary of Peer Review Panel Meetings

Date	Meeting Type	Meeting Topic(s)	Outside Attendees
July 21, 2014	Conference call	Introductions	Leland Deck (EPA), Jennifer Richkus (RTI)
August 6, 2014	Conference call	Review of charge	Leland Deck (EPA), William Meroney (EPA), Jennifer Richkus (RTI)
August 15, 2014	Conference call	Discussion of Base Case v5.13 structure	Leland Deck (EPA), William Meroney (EPA), Jennifer Richkus (RTI)
August 21, 2014	Conference call	Renewable portfolio standards, heat rate improvement (HRI), life extension costs	Leland Deck (EPA), William Meroney (EPA), Jennifer Richkus (RTI)
August 29, 2014	Conference call	Turndown constraints, load duration curves	Leland Deck (EPA), William Meroney (EPA), Jennifer Richkus (RTI)
September 3, 2014	Conference call	In-person meeting agenda, transparency and recognizing tradeoffs	Leland Deck (EPA), William Meroney (EPA), Jennifer Richkus (RTI)
September 9, 2014	In-person meeting	Review of panel materials; see Appendix D for the meeting agenda	Leland Deck (EPA), William Meroney (EPA), Ryan Sims (EPA), Venkatesh Boddu (ICF), Jennifer Richkus (RTI)
September 22, 2014	Conference call	Emission control technology, fixed operation and maintenance costs	Leland Deck (EPA), William Meroney (EPA), Jennifer Richkus (RTI)
September 30, 2014	Conference call	Report development	Jennifer Richkus (RTI)

Peer reviewers were provided with an honorarium for approximately 50 hours of effort and travel costs to attend the in-person meeting. The panel chair was provided with a larger honorarium to oversee the review and guide the technical and substantive aspects of the peer review. The following sections provide the findings of the peer review panel.

SECTION 3
SUMMARY OF FINDINGS

The purpose of this independent peer review panel was to provide expert feedback on whether the analytical framework, assumptions and applications of data in IPM Base Case v5.13 are sufficient to EPA's needs for estimating the economic and emissions impacts associated with the power sector and emissions policy alternatives. While the panel identified a number of strengths associated with the model, the panel has also provided several areas for investigation and additional recommendations for EPA's consideration:

- Pollution control technology options and costs are well represented in the model.
- The model exceeds other model capabilities in providing a relevant feedback mechanism between the electric power model and key fuel inputs that drive simulation results.
- Although simplifying assumptions is necessary to conduct analyses of complex systems such as the power sector, the model contains oversimplifications in the reference case that may have adverse impacts on the model results (e.g., load duration curves and treatment of renewables).
- An analytical version of the linear program would greatly enhance transparency and the ability of the public to understand how the model works.
- Source(s) of underlying assumptions are referenced in an incomplete manner in several sections of the documentation such as variable operation and maintenance (VOM) costs, fixed operation and maintenance (FOM) costs, life extension costs and financial assumptions.
- A mixed integer programming framework would do more to capture the entry and exit reality and would then obviate the need to use model plants.
- Features of the current model that do not exist and would be desirable include: endogenous determination of end-use energy efficiency and demand response in dispatch, endogenous improvement in boiler heat rates, endogenous construction of new interregional transmission capability.
- There is a current absence of consideration of renewable integration factors in IPM. IPM modelers should review the detailed approach used in NREL's Regional Energy Deployment System (ReEDS) model (Short et al., 2011).

- The panel recommends consideration of the addition of one more season—the shoulder season—to differentiate the spring and fall with respect to load duration curves (LDC).

SECTION 4
PANEL FINDINGS

From the perspective of the peer review panel, market models are by necessity just simplified representations of complex, real-world markets designed to provide insights about how policy or market fundamentals will change outcomes. The panel understands that it is in this spirit that EPA has employed IPM by ICF for examining the effect of various environmental policies on the electric power sector.

The review panel also notes that real-world complexities only grow when considering markets for electric power that exist at the intersection of economics, markets and power system engineering. Some of the simplifying assumptions that distinguish a power market model from a power market itself are more costly than others in causing the model to deviate from the real world. Improving on some simplifying assumptions to better reflect market realities may yield important insight that may be crucial to understanding the effects of environmental policy on the electric power system and associated costs. Doing so, however, may be costly from a model design, maintenance and production standpoint.

It is in this context of balancing model complexity with the need to extract useful and transparent insights that the review panel offers this document of observations for further improvements and enhancements to IPM used by EPA to evaluate the effects of environmental policy on the electric power sector. Because each panel member has examined IPM from differing experiences and perspectives, the recommendations are not listed in any particular order, but rather are to be interpreted as committee consensus on issues that should be addressed for the next iteration of IPM.

By necessity, many simplifying assumptions have been made in the development of the reference case in order to allow for the model to solve in a reasonable amount of time. However, the panel has raised a number of instances where oversimplifications in the reference case may be problematic (e.g., load duration curves and treatment of renewables). For the sake of transparency, as well as for internal EPA decision making, it may make sense for EPA to develop a hierarchy of the market characteristics or other details that are most important to represent in greater detail at the expense of others. This hierarchy may change over time between reference cases as EPA’s policy agenda changes. From the current documentation, it is difficult to discern how EPA has determined the appropriate level of detail with which to represent various aspects of the system and markets.

While EPA has emphasized the importance of maintaining a computing time (approximately 7 hours) that allows model runs to be turned around quickly in order to meet the demands of policy makers, EPA should investigate the implications for both computing time and model results of adding complexity to some of the runs in some of the areas the panel identifies.

Ultimately, the value of EPA's base case depends on the extent to which EPA can use it to develop robust analyses of the policies it will be proposing and finalizing over the life of the base case. New policy approaches will require new capabilities or features in the base case, and the base case should be developed with some insight into what those features should be. In practice, this may be somewhat challenging because the base case is likely to be finalized before key policy design decisions are made. That said, there is generally some sense of what is coming, and it would be useful for the documentation to include some discussion of relevant features that could be valuable, even if they are ultimately not included due to technical or budget/time constraints. The role of IPM in analyzing regulations that affect power sector CO_2 emissions, for example, emphasize the importance of this point. For example, the current lack of endogenous demand-side energy efficiency in the model means that when EPA analyzes policy scenarios, a key compliance option is not actually competing with alternatives, but must be forced in through exogenous assumptions.[1] This limits the value of EPA's analysis for stakeholders. Similarly, the base case's currently crude representation of state renewable portfolio standards (RPSs) may not matter much for an initial national-level analysis of the proposal, but may impact the value of state- or regional-level results depending on the role that existing RPSs play in implementation plans.

The remainder of this section addresses the strengths of IPM identified by the panel, followed by a discussion of the nine key issues that the panel views as most significant and worthy of further development for the next base case.

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[1] As is discussed later in this report, the reference case also does not include the option to endogenously invest in heat rate improvements, though endogenous heat rate improvement options in policy scenarios run in support of the Clean Power Plan. This inconsistency is also problematic for determining the impact of policy scenarios.

Strengths

The panel would like to recognize some of the strengths of IPM and highlight some of the many improvements that EPA has made in updating the model for Base Case v5.13.

The detail with which pollution control technology options and costs are represented in the model and refined by EPA with each version of the base case remains a real strength of IPM. These inputs, as well as the level of detail at which existing federal Clean Air Act (CAA) regulations are represented in the base case, provide a strong foundation for analyzing the implications of the costs (and, after exporting results to air quality models, the benefits) of regulations affecting conventional pollutants and mercury. The ability of the model to allow for the detailed representation of a variety of energy and environmental policies, including complicated features of market-based programs, is also an ongoing strength. The accuracy of the emissions control costs and their relationship to retirement decisions were borne out in the 2011 PJM study of the effect of MATS and CSAPR, which used EPA cost data and PJM revenue and going-forward cost data to come up with what has turned out to be a reasonably accurate assessment of generator retirements in PJM (PJM Interconnection, 2011).

The expansion of model regions from 32 to 64 is also an important feature of v5.13. This significant improvement allows the model to better represent current power market operations, represent existing transmission bottlenecks even with RTO regions, and now accurately models transmissions zones with regional transmission organizations (RTOs). As we note later in this report, however, more could be done to improve the model's representation of transmission.

We also commend EPA for continuing to update the representation of domestic coal and natural gas market conditions. The coal and gas modules are crucial to providing a relevant feedback mechanism between the electric power model and key fuel inputs that will drive simulation results. This is a strength of IPM that other commercially available software used by utilities and RTOs does not always have where fuel prices are taken as given, and scenario analyses are necessary to get a sense of the differential effects of fuel price dynamics.

The volume of detailed data on FOM and VOM costs for all unit types, including some coal steam by age and nuclear units, is very helpful in independently verifying some results that come out of model runs, but, as we mention, better documentation of sources would be helpful.

Transparency and Documentation

The IPM documentation is a great source of data and information ranging from capital costs to VOM costs to FOM costs, heat rates, and the cost and performance characteristics of emissions controls among other items. However, while some information is well documented (e.g., emissions control from Sargent & Lundy), others are not. Explicit equations defining the model itself would be very helpful and make the results from IPM more transparent. Specifically, publishing an analytical version of the linear program would greatly enhance transparency and the ability of the public to understand how the model works.

Throughout the model documentation, there are many places where the source(s) of underlying assumptions are referenced in an incomplete manner. For example, the documentation contains very limited information on the approaches or information used to develop assumptions for VOM costs, FOM costs and life extension costs, as well as how they are actually applied in the model.[2] Similarly, the panel noted a number of areas in the Financial Assumptions section (Section 8) where assumptions are inadequately documented or their application insufficiently explained. EPA and ICF should comb through the full documentation to identify and address assumptions that do not cite original sources with sufficient specificity, and to identify areas where more explanation is needed about how the assumption is applied in the model. It would also be helpful for EPA and ICF to identify assumptions that differ from generally accepted values or those used by other well-known entities (especially other government entities), why the choice of a different assumption was made, and the potential implications of this choice for policy analysis.

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[2] For example, it is not clear from the documentation that FOM costs are assigned to a unit based on its age at the start of the model, and do not escalate as the unit ages over the course of the model. Similarly, it is not clear from ***Table 4-10*** in the IPM documentation that life extension costs are applied annually in the model. It is also not clear how the cost is applied to nuclear units, which are not able to double their lifetimes in the base case.

Implications of Linear Program Structure

It is not clear that the social cost–minimizing solution supports a competitive equilibrium in wholesale power markets (with both energy and capacity markets or energy-only markets) or traditionally regulated regimes. The documentation at minimum linking the "shadow prices" that come out of the linear programming (LP) framework with actual prices paid to generation, or available to be collected by generation, either in competitive wholesale markets or in traditional cost-of-service regimes would be helpful to understand IPM results. Another way of phrasing this would be to check that under the shadow prices computed by IPM, entry, exit and retention decisions are "individually rational" such that at these prices, resources would do exactly the same thing IPM is saying will happen in the social cost minimum.

The current framework uses a dynamic linear program, but, in reality, entry and exit decisions are lumpy, all-or-nothing decisions. Units cannot be divided up as if they were indivisible. A mixed integer programming framework would do more to capture this reality and would then obviate the need to use model plants, and each individual unit could be modeled with all of its details as known in the National Electric Energy Data System (NEEDS) (U.S. EPA, 2014).

One big advantage of an LP formulation is ease of computation. In addition, under very general (nondegeneracy) assumptions, linear programs generate unique global optima, avoiding the multiple local optima outcome that might result from nonconvex programs and/or less rigid simulation-type alternatives where iterative convergence algorithms are used to find approximate equilibria.

However, a least-cost solution from a national LP model is equivalent to optimal solutions at all of the state/regional levels only if strong efficient market assumptions are made. Put differently, real-world characteristics of economic agents may lead to a situation in which the national solution that is computed by the LP is not incentive-compatible at the subnational levels. With companies, power pools, state regulatory bodies and state legislatures all in play here, there are likely to be market and political power constraints on the global solution that operated at the regional or state levels. Put differently still, this means that a fairly large number of what economists call side payments and possible alliance formations would be necessary in order for the incentives from the national LP to be completely compatible at the subnational level, which seems very unlikely. This is where the documentation of the shadow prices and linkages to payments available in competitive markets or in a cost-of-service regime would be advantageous. One standard test for this could be comparing results between the model and the real world even if only for a base year or two. However, the current National Energy Modeling System (NEMS) calibration precludes this, but it would be a good diagnostic to consider anyway.

Demand Response and Energy Efficiency

The current model in use by EPA does not allow for the endogenous determination of energy efficiency options or demand response in dispatch. These two options have become key parts of wholesale power markets and in integrated resource plans executed by vertically integrated utilities, but are always evaluated implicitly or explicitly based on the economics. The base case would be enhanced by seeing how much efficiency and demand response would enter the model prior to examining any policy cases.

A key challenge for IPM in its ability to evaluate the impacts of policy scenarios is the lack of price-responsive demand. While the documentation reflects some capability to implement price elasticities, EPA noted that this feature has been used under only limited circumstances. EPA also noted that the lack of retail price characterization in the model makes it challenging to effectively implement price response in demand.

The panel discussed that the flattening of demand projections has been largely due to income, rather than price effects. Further, because of the extent to which EPA currently simplifies load duration curves, price effects are likely to be smaller than might otherwise be estimated. EPA should consider whether there is opportunity within IPM for capturing income effects.

In order to effectively model regulations that affect CO_2 emissions from the power sector, EPA should consider options for allowing energy efficiency investments to compete with other potential compliance options within the model. While the simplest—from the perspective of model construction—would likely be to allow energy efficiency to displace generation on the supply side (via model plants that are “negawatt” generators), even this approach requires the development of location-specific energy efficiency supply curves, a challenging undertaking that has the disadvantage of putting the demand on the supply side of the equation. Another alternative would be to develop representations of distribution households and commercial and industrial (C&I)

customers by size and income and allow “representative households or businesses” to make efficiency decisions under a budget constraint (i.e., how much can they save vs. the investment) to keep the demand on the demand side of the market. Such an approach is not easy in any way, but given the trends in overall energy consumption, it may prove fruitful. In either case, the panel recommends that EPA work with ICF to evaluate the full range of options for including energy efficiency, and include this discussion in the model documentation.

It seems odd to have fixed electricity demands drive the solution of the IPM linear program base case as changes in demand that occur in response to changes in economic and noneconomic conditions over time seem like some of the most important adjustments that would take place in both base case and policy projections. The fixed demands for the IPM base case seem to also come from the NEMS model, which raises the question of consistency between the costs and prices in the NEMS model and in IPM. If the upstream cost/price results from IPM are different than those from NEMS for the scenario used to generate the NEMS demands that are then fixed in IPM, this seems like a large potential inconsistency in the baseline, which could be even more significant in any policy case run from that baseline. One solution would be to estimate demand curves (demand vs. price functions) with NEMS that are then incorporated into IPM. This would insure both the internal consistency of the supply/demand/price picture coming out of IPM and its suitability for considering policy alternatives. The following section discusses other issues regarding the use of NEMS electricity demands.

Renewables

The IPM Base Case v5.13 has a very simplified representation of variable resource renewable energy technology (VRRET) such as wind and solar. IPM benefits wind and solar by ignoring some of the integration issues associated with them (e.g., induced reserve requirements and curtailments) and yet penalizes the same technology by adopting capital-cost penalty functions and by failing to consider the possibilities for new transmission, demand response and geographic diversity of wind siting. The only integration issue addressed directly by IPM is the capacity value of wind and solar, but again the representation is simplified and nondynamic.

VRRETs like wind and solar have unique characteristics that require unique modeling approaches. The most significant difference between VRRETs and conventional generators like coal and gas-fired power plants is the variable and uncertain nature of the resources VRRETs depend on, which limits their dispatch ability. This variability and uncertainty precludes system operators from dispatching VRRETs at will. As a result, the full capacity of a VRRET generator cannot be counted on to be available when peak loads need to be met; additional reserves, primarily spinning reserves, are needed to ensure that loads are met when generation from VRRETs declines unexpectedly, and when VRRET generation is higher than expected, it may not be possible to use it all because conventional generators may not be able to ramp down fast enough or low enough to accommodate the VRRET generation.

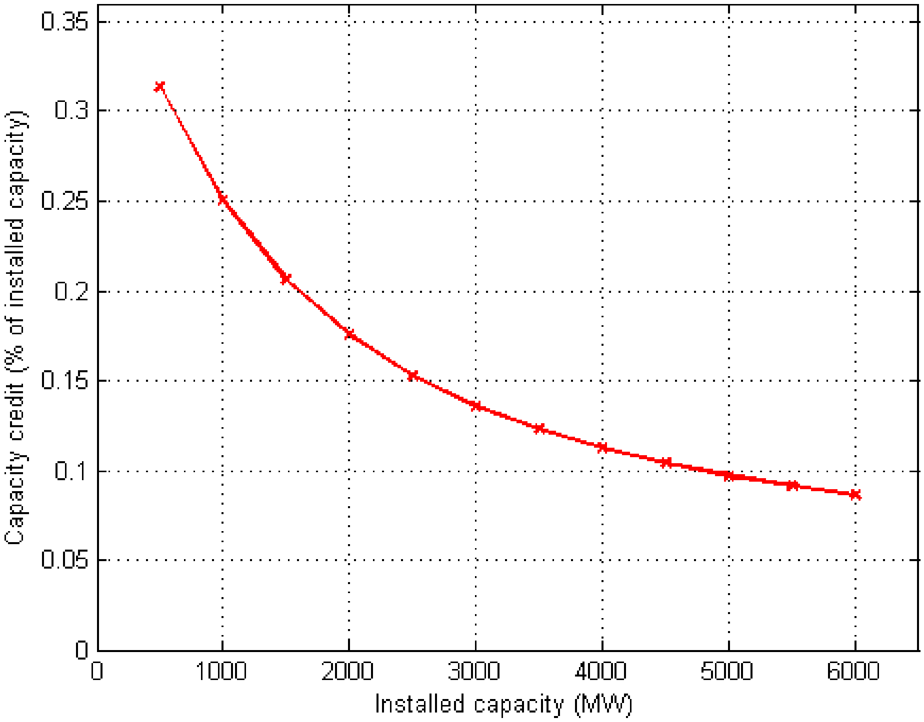
Spinning reserves are usually conventional generators that are operating, but at less than their full capacity. As such, they can be quickly brought up to full capacity should the system require additional power. Because the generation from wind and solar can drop unexpectedly, generation from these technologies must be backed up by spinning reserves. Since IPM does not account for spinning reserves, wind and solar are given an inappropriate advantage in IPM. This advantage may be fairly easy to correct in IPM by adding a spinning reserve constraint in which the contribution from operating dispatchable rotating generators contributes positively toward meeting the constraint, and the addition of VRRETs contributes negatively.

If wind or solar generation increases unexpectedly, it may not be possible to ramp down conventional generators fast enough or low enough to accommodate the renewable energy. In this case, the renewable energy cannot be used. Such curtailments of wind and solar will not be significant until the fraction of load met by wind and solar is significantly higher than it is today (today’s curtailments of wind and solar are due mostly to transmission limitations). However, in modeling climate change or high natural gas prices, penetration of wind and solar may climb to levels where the unused VRRET energy due to ramping constraints significantly impacts the overall economic viability of these VRRETs. Since IPM makes no estimate of the curtailments from wind and solar, it again inappropriately advantages VRRETs. This IPM limitation may be largely removable by adding a step-wise linear function that accounts for curtailments by reducing the output of VRRETs as more VRRET capacity is installed in a utility system.

IPM does consider contingency reserves that are used to continue to meet loads when there is a system failure (e.g., an operating generator malfunctions or a transmission line is damaged). IPM uses a reserve margin constraint to ensure there is enough capacity in the system that loads can continue to be met even when there is such a failure. The full capacity of dispatchable generators like coal and gas contributes to this system reserve margin. However, since wind and solar resources are variable, electric system planners do not count their full capacity toward the reserve margin. But most planners do count a fraction of wind and solar capacity toward the reserve margin requirement because statistically there is a reasonable probability that some fraction of the wind or solar capacity will be generating at the time of peak load and a system outage. Similarly, IPM counts a fraction of wind and solar capacity toward the reserve margin as specified in ***Tables 4-21*** through ***4-23*** for wind and ***Table 4-29*** for photovoltaics (PV) and solar thermal.

The wind capacity values in ***Tables 4-21*** through ***4-23*** in the IPM documentation are reasonable for the initial wind installed into a utility system. However, as shown in ***Figure 4-1*** below, the capacity value of wind declines as more wind is added to a utility system. The decline will be more rapid if all of the wind capacity is installed at the same location because if the wind is not blowing at that location when a generator or transmission line fails during a peak load time, adding more capacity will not increase the contribution to the reserve margin requirement. However, were the next increment of additional wind located at a different site, there is a better chance that wind will be available from at least one of the sites (i.e., with geographic diversity, the wind sites will have a higher overall capacity value). Geographically diverse wind sites can also reduce curtailments and the need for spinning reserves. IPM’s wind capacity values do not account for either the level of wind penetration or the geographic diversity of the wind sites selected. Once again, the constant IPM values for wind capacity values inappropriately advantages wind. However, it should be possible to approximate a declining capacity value for wind in IPM using a piece-wise linear curve to reduce the capacity value of wind as a function of the penetration level. The use of only 64 regions in the IPM Base Case v5.13 would limit the ability to directly capture geographic diversity in wind sites, but an approximate method such as that used in NEMS could be applicable.

Figure 4-1. Declining Wind Capacity Value with Increasing Wind Penetration



Source: Milligan, 2011

IPM's treatment of the capacity value of solar has the same shortcomings as that described above for wind. However, unlike wind, the constant solar capacity values shown in ***Table 4-29*** of the IPM documentation are not appropriate for even the initial solar installations in a utility system. Because peak loads generally occur at the time of summer air conditioning loads, solar generation is much more likely to be available at that time. Thus, the capacity value of the initial solar installations in a utility system may be as high as 40 to 80% of the solar capacity. On the other hand, the capacity value of PV generally declines even faster than that of wind as PV penetration increases. Once enough solar has been installed to decrease the summer afternoon peak below the summer evening peak, the capacity value of PV falls off precipitously since the sun has set or is at least low on the horizon by that time. As with wind, it should be possible to approximate a declining capacity value for PV in IPM using a piece-wise linear curve to reduce the capacity value of PV as a function of the penetration level. Geographic diversity of solar does not yield as large a benefit as it does for wind because the solar resource is geographically more homogenous than that of wind.

The integration issues with respect to solar thermal power are the same as those of PV with one major exception. Solar thermal power can take advantage of thermal storage of the working fluid to generate power at a later time. The IPM documentation does not say explicitly whether it considers this option, but the solar thermal generation profile presented in ***Table 4-28*** of the IPM documentation suggests that no thermal storage is assumed by IPM. This needs to be corrected as the primary reason for adopting solar thermal electric generation capacity is its ability to store energy for dispatch at a later time. Ideally, IPM would endogenously determine the optimum level of thermal storage associated with each solar thermal plant, but once again the relationships are highly nonlinear and difficult to capture in a single LP optimization model. NREL has conducted considerable work in this area and should be consulted, probably with the ultimate goal of exogenously selecting a thermal storage system with a fixed number of hours of storage[3] to be considered for all possible solar thermal plants in IPM. Since the marginal cost of another increment of thermal storage is relatively inexpensive, the optimum storage size is normally quite large, which would allow IPM to assume that the solar thermal plant is essentially dispatchable, alleviating the need to deal with curtailments, additional reserves and nonunity capacity factors.

IPM modelers should review the detailed approach used in NREL’s ReEDS model and the more approximate methods of the U.S. Energy Information Administration’s (EIA’s) NEMS model for reserves, curtailments and capacity credit. Because these models are recursive optimizations,[4] they can and do use highly nonlinear representations (calculated between the annual optimizations) to compute integration

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[3] An hour of thermal storage for a solar thermal system is defined as the amount of thermal storage required to run the solar thermal generator at full output for an hour.

[4] In a recursive optimization model, an optimization is conducted for each model period. For example, the model optimizes for year *n*, then moves on to optimize for year *n* + 1. The optimization for year *n* may include multiple future periods (e.g., *n* + 1, *n* + 2, …), but only the year *n* results are used from that optimization. The next optimization will start with year *n* + 1, and may optimize over years *n* + 1, *n* + 2, etc., but again, only the results from year *n* + 1 are retained. In NEMS, this approach is used for electric-sector capacity expansion. It allows the NEMS electric-sector capacity expansion to make decisions with some foresight about the future, while at the same time allowing the period *n* electric capacity expansion results to be part of the larger economy-wide equilibrium methodology within NEMS for period *n*. It also has the advantage that nonlinear relationships can be introduced into the NEMS electric capacity expansion if some inputs for period *n* + 1 depend nonlinearly on the results from period *n* and/or earlier periods. NREL’s ReEDS model uses a similar recursive approach with the simplification that each optimization is just for period *n* (i.e., there are no decision variables for periods *n* + 1, *n* + 2, etc.). This reduces the size of each optimization and allows the introduction of nonlinearities with respect to the variability of wind and solar, but limits the foresight in the model; the only foresight afforded the investor modeled by ReEDS is an exogenously specified trajectory of expected future conventional fuel prices.

factors. The single linear optimization approach of IPM will preclude the direct application of the ReEDS and NEMS methods, but as briefly mentioned above there may be approximations that would be considerably better than the current absence of consideration of these factors in IPM. There is also always the option of reconstructing IPM to make it solve recursively as ReEDS and NEMS.

For wind and solar, the IPM documentation cites NREL as the source of the capacity factors, but does not provide a reference or a contact. The IPM documentation states that the capacity values for wind and solar were derived from Annual Energy Outlook (AEO) 2012 results using the ratio of the NEMS capacity values to the NREL capacity factors. This is not a reasonable approach for two reasons: (1) the NEMS model used in AEO has limitations with respect to its calculation of capacity values for wind and solar, and (2) the AEO base case is a very low wind and solar penetration scenario that should yield higher capacity values than would be possible in a high wind/solar penetration scenario. At a minimum, the IPM documentation should include information on how NEMS makes its capacity value calculations.

Electric power storage technologies can mitigate the variability of wind and solar power. While the IPM documentation mentions that pumped storage is modeled, details are not provided. New pumped storage and compressed air energy storage should be considered in IPM. Because of their ability to ramp up and down quickly, reservoir-based hydroelectric facilities can also mitigate the variability of wind and solar power. It is not clear how IPM handles water releases at hydro plants for nonpower purposes (e.g., irrigation).

IPM should also consider demand response options that can mitigate the variability of wind and solar power. For example, on most days, the Electric Reliability Council of Texas (ERCOT) receives more offers for “responsive reserves” from the demand side than the 50% (1150 MW) it is legally allowed to accept (Tweed, 2011).

Because integration requirements become more difficult as more VRRETs are added to a utility system, the penetration of VRRETs is naturally limited in the real world. Since IPM does not capture this increasing integration difficulty, it is forced to use a surrogate method for limiting the penetration of VRRETs. For wind, this is at least partially effected by adopting the wind cost classes and their corresponding capital cost multipliers from EIA’s NEMS model. As shown in ***Table 4-24*** of the IPM documentation, IPM’s wind capital cost multipliers range in value from 1.0 to 2.0. The

IPM documentation quotes NEMS documentation to the effect that these multipliers account for “such factors as distance from existing transmission, terrain variability, slope and other causes of resource degradation, site accessibility challenges, population proximity, competing land uses, aesthetics, and environmental factors.” These are real factors that do need to be accounted for. However, as shown in ***Table 4-17*** in the IPM documentation, over 90% of the wind resource is included in cost class 5, which doubles the capital cost of wind. This is an unrealistically large cost increase that is not evident in practice. In NEMS, and the panel suspects in IPM, this doubling of the cost of wind for 90% of the wind sites precludes wind from capturing a significant share of the electric power market. The August 2014 NEMS documentation of the NEMS “renewable fuels module” cites a report by Princeton Energy Resources International (PERI) as the source for these numbers. One of the peer reviewers for this review was the NREL point of contact for this PERI work. NREL never endorsed the report as the fraction (90% or more) of wind resources included in the highest cost bin (2 x cost) are regarded as too high. NREL’s ReEDS model includes some of these costs explicitly; for example, for each wind resource site in ReEDS, an additional cost is added to the wind capital cost based on the slope of the terrain at that site. The peer review panel recommends that these cost multipliers be reviewed independently using actual field cost data and modified appropriately. No such cost multipliers are used in IPM for solar.

Although not mentioned in the IPM Base Case v5.13 documentation, IPM apparently uses an additional method for limiting the penetration of wind. IPM constrains the annual generation from wind to be no more than 20% of the annual generation in each region. This artificial limit has already been exceeded in Iowa, where over 27% of the 2013 electric load was met by wind energy (U.S. EIA, 2014). The constraint is even more egregious in states/regions like Wyoming and North Dakota that have substantial wind resources that could be used to generate wind power for export to nearby regions with larger populations and loads; clearly, this 20% limit would preclude much of this potential export capability. The peer review panel recommends that this 20% constraint on wind generation be removed from IPM.

Were EPA/ICF only to remove the IPM 20% limit on wind and reduce the cost multipliers in accordance with actual data, in some scenarios, wind penetration might increase beyond reasonable levels. Thus, it is imperative that these IPM modifications be made in concert with the implementation of the integration factors described above (e.g., curtailments, additional reserve requirements and declining capacity values).

To capture the variability of wind and solar generation, IPM uses the 2011 hourly loads in each region and the regional wind and solar generation profiles illustrated in ***Tables 4-20 and 4-28***, respectively, to identify which load duration curve section the wind and solar generation contributes to. The illustrative PV summer profile has some (very small) PV generation even in the middle of the night. If this is generation from moonlight, then the winter profile should have the same, but it does not. This is a minor point, but the panel suggests using a different PV summer profile for illustrative purposes.

VRRETs also differ from most conventional generators in that the bulk of the cost of their power is the capital cost of the wind and solar plants themselves since they have no fuel costs. Thus, it is more critical for VRRETs that financing of capital costs be accurately modeled. Currently, IPM does not distinguish between regulated and deregulated regions; IPM uses a cost of capital that is a weighted average between regulated and market financing. As discussed in the Financial Assumptions section of this report, the use of an average cost of capital can disadvantage high capital cost technologies like renewables and nuclear because the low cost of capital of a pure regulated utility is not included.

Finally, wind and solar thermal power also differ from conventional generators in that their resources are often best in regions where there is little population and consequently little load (people do not generally want to live in exceptionally windy areas or desert areas with high direct insolation). These areas of limited population/load generally also do not have significant transmission links to other regions. Therefore, to access some of the best wind and solar thermal resources will require the construction of new transmission lines. This process is currently underway in Texas to move power from the strong winds of west Texas to population centers like Dallas and San Antonio. IPM Base Case v5.13 does not allow for the building of new transmission lines. As discussed under Interregional Transmission of this peer review report, modeling the addition of new transmission lines is a difficult undertaking due to the highly nonlinear nature of AC power flow and the nonproportional cost of power lines. However, the review panel recommends that transmission expansion using DC power flow approximations be considered for IPM.

Load Duration Curves and Seasons

The 8,760 hours that comprise a single year are grouped by IPM into 2 seasons (May 1–September 30 and October 1–April 30). Within each season, IPM uses a six-step piecewise linear representation of LDC. The 2 seasons and 6 time segments per season account for the entire year in 12 total segments. The motivation for the LDC approach to dealing with time is computational constraints. Without such constraints, a more detailed modeling approach would be to drop LDCs all together and model the year as 8,760 chronologic hours with day-ahead unit commitment and real-time economic dispatch by known RTO or vertically integrated utility region. This would open the door for even more detailed modeling of system dispatch (e.g., unit commitment and ramping) that would better represent how the system actually operates and would likely influence the capacity factors at which various different types of units operate. However, the computational constraint that the model must solve in 7 hours is real, and the application of seasons and LDCs is a popular approach to the computational problem.

The choice of two seasons and six segments per season is an important one that the panel feels has not been investigated sufficiently by EPA. EPA points out the virtue of seasonal LDCs instead of a single annual LDC in Section 2.3.5 of the IPM documentation. EPA does not state it this way, but the LDC approach captures issues related to daily dispatch and does not capture issues related to weekly or seasonal dispatch; therefore, the application of LDCs to seasons is better than an annual LDC. However, LDCs really only apply to single days, maybe a week, and so a more robust application of the seasons/LDC approach would be 365 seasons (i.e., a single LDC for each day of the year where unit commitment and economic dispatch could be brought to the forefront to better account for how systems are actually operated).

Recognizing the computational infeasibility of such an approach, the panel recommends at least serious consideration of the addition of one more season—the shoulder season—to differentiate spring and fall. A three-season approach would still treat the summer as 5 months (allowing for a representation of the summer ozone season for Clean Air Interstate Rule compliance), but would treat winter as only 3 months with the other 4 months grouped together in a spring/fall season. This would allow IPM to better capture the operation of intermediate load coal and oil steam plants that, in reality, are often totally shut down in the shoulder seasons. Recognizing computational constraints, a reduction in the number of segments in the LDCs from 6 to 4 would amount to an identical number of 12 annual segments (3 x 4 instead of 2 x 6). Another approach that would preserve the 12 time segments would be 4 seasons and 3 time segments per season. There are clearly tradeoffs between more seasons and more time segments. It is the understanding of the panel that these tradeoffs are not well understood by EPA. If the two-season, six-segment approach is retained, it should be justified in documentation.

In constructing the LDCs for the two seasons modeled by IPM, a single year of data (2011) was employed. The data are hourly load data in each IPM model region. A more robust approach would take an average over multiple years of data, thereby generating a more realistic projection than that from a single year of data. The panel understands that the justification for using a single year instead of an average over multiple years is to synchronize with the treatment of time in the atmospheric transport models that EPA sometimes uses in conjunction with IPM. The panel recommends that the multiyear approach be adopted across the board.

NEMS for Business-as-Usual

There are many benefits to and issues in using NEMS to calibrate the IPM Base Case. The biggest benefits are that it is fairly detailed, openly available and well known. However, we recommend that EPA give consideration to some of the issues with this approach. One issue is that it is fairly constrained around the current state of the energy system because it is strongly calibrated to the current state of the energy system; factors adjusted to match those base year conditions are not unique, such that projections probably become less reliable as time moves on past a decade or two, and the model may be less responsive to large policy changes by the end of that time frame than would be realistic. In addition, nonlinear regulatory rate setting rules, market power and other departures from competitive market assumptions are difficult or impossible to implement within this model structure. Finally, both NEMS and IPM appear to be fairly conservative regarding the amount of technological and institutional change that might be expected by the end of the modeled time horizon. What are the justification for and implications of these assumptions?

Interregional Transmission

While the IPM model is a pipes-and-bubbles model between the 64 regions, there are transmission constraints within each of the 64 model regions, and generator deactivations may create the need to build a great deal of transmission to allow units to retire in a reliable manner. One suggestion is for EPA to examine the use of internal regional transmission constraints to get a better sense of the constraints on dispatch. The second suggestion to account for transmission costs (and/or reliability-must-run [RMR) generator costs) associated with generator retirements, is to estimate the “average” cost of new transmission and RMR associated with retirements to account for these costs in the baseline and in policy cases.

The construction of the IPM baseline scenario precludes the building of new electric transmission capacity which seems overly restrictive, especially for certain types of scenarios (e.g. technological breakthroughs in renewables electricity generation that work best in areas that are remote, etc.). In addition, the treatment of transmission capacity from region to region in IPM is a pipe and bubble formulation which aggregates both loads and generating units.

Computational and data limitations probably necessitate some aggregation although parallel processing methods may help make the computational limits less restrictive in the near future.

Because of the way the grid works, some non-linearities can be represented in this way and some transmission studies have informed the pipe and bubbles constraints, but the model is still limited because of its underlying formulation being pipe and bubbles which precludes consideration of point to point transmission that would better represent the actual operation of the current and future electricity grid. Additional resolution in transmission capacity should be considered.

Financial Assumptions

The current financial modeling assumptions seem to apply across the country and may not be relevant in some organized ISO/RTO wholesale power markets and should be differentiated by area. For example, in PJM, much of the new entry taking place across the footprint is merchant only, while in some zones (e.g., Dominion) it is a vertically integrated entry for the most part. Additionally, the financing assumptions based on 2008–2012 require major reworking as this includes the effect of the worst financial crisis since the Great Depression, and current financial markets world-wide are showing much lower returns on debt and equity. To say the current levels are “unsustainable” or “artificial” is irresponsible and does not reflect experience in Japan, where they are two decades into a similar crisis and still have lower capital costs as a result. One example of an assumption that does not make sense is a weighted average cost of capital (WACC) for merchants that is higher for a gas combustion turbine (CT) than a coal or nuclear base load resource or for environmental retrofits on coal units. Reality would indicate that coal and nuclear are far riskier than a CT, and biasing the cost of capital in favor of retrofits over some new resources may explain why the MATS analysis found so few coal units retiring and opting to retrofit as opposed to seeing retirements that have actually taken place and the prevalence of new build gas units.

IPM Base Case v5.13 includes a number of costs associated with the continued operation, maintenance and refurbishment of power plants. These include FOM costs, environmental retrofit costs and life extension costs. The peer review panel finds the environmental retrofit costs of IPM to be representative of real-world costs and a useful data set for all modelers. The FOM costs and the increase in those costs for coal and oil/gas plants with the age of the plant as shown in ***Table 4-9*** of the Base Case v5.13 documentation also appear reasonable. Although not stated in the IPM documentation, the increase in FOM cost is apparently applied only once to those plants that exist at the start of the model run (i.e., 2016). The peer review panel recommends that these increases in FOM costs be also applied to new plants when they reach the ages shown in ***Table 4-9*** and to plants that existed in 2016 as they continue to age into their next decade. The peer review panel further recommends that increasing FOM costs with age be considered for combustion turbines, combined cycle, integrated gasification combined cycle (IGCC), renewables, storage, hydro and fuel cell plants. Nuclear should also be added to ***Table 4-9***, and increasing FOM costs should be considered for nuclear as well.

Table 4-10 of the Base Case v5.13 documentation presents the costs to double the lifetime of generation plants in IPM. The panel understands that the life extension cost is based on FERC Form 1 data and is in addition to environmental retrofit and FOM costs. After extensive discussion with ICF and EPA experts, it became clear to the panel that these life extension costs are relatively low because they cover only the replacement of a limited number of essential plant components that may fail despite regular maintenance efforts. The panel also understands that these costs have been reviewed extensively by ICF and EPA. Thus, the panel recommends that the Base Case v5.13 documentation be revised to convey these facts about the life extension costs. In particular, the documentation should be expanded to state that these life extension costs

- are in addition to FOM costs,
- cover only the replacement of a limited number of essential plant components that may fail in spite of regular maintenance efforts, and

- are applied once for each power plant in only the year during which that plant would have reached its original life term.

Heat Rate Improvements

The IPM Base Case v5.13 includes no provision for endogenous investment in heat rate improvements (HRIs) at coal boilers. However, the version of IPM used in the analysis that supports the Clean Power Plan does allow for coal boilers to invest in a 6% HRI at a cost. This inconsistent treatment of HRI between the base case and the Clean Power Plan scenarios is clearly not appropriate. The panel understands that this resulted from the recent development of the HRI capability that was not available when the base case was run. Future base cases should include the endogenous HRI option.

One important aspect of the potential for CO_2 emissions reductions from investments in HRI are changes in utilization at boilers that do and do not make improvements. The modeling framework employed by IPM does capture these effects and is a strength of the approach. A problem with the IPM approach is that HRI is treated as binary rather than continuous. It is modeled as an all-or-nothing proposition when in fact it could be modeled incrementally per the EPA commissioned work by Sargent & Lundy in 2011 that examined the costs and different opportunities for HRI. Finally, in wholesale competitive markets, there are academic papers showing HRIs of the fossil fleet over time, and perhaps these improvements have already been exhausted.

SECTION 5

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APPENDIX A

CONFLICT OF INTEREST ANALYSIS AND BIAS QUESTIONNAIRE

Instructions:

This disclosure form has been developed in accordance with EPA's Peer Review Handbook, 3rd Edition (2006). The questions help identify any conflicts of interest and other concerns regarding each candidate reviewer's ability to independently evaluate Integrated Planning Model's (IPM®) Base Case v5.13. The Peer Review of the Base Case (as used in IPM for EPA's power sector analyses) will provide EPA an independent evaluation of whether IPM meets EPA's goals for analytical transparency, and recommendations on ways to improve the Base Case and related documentation. Analytical transparency is a critical component to make it possible for stakeholders and expert reviewers to examine specific estimated impacts of potential new policies, to evaluate the technical credibility of EPA's projections and to comment on the consequences of modeled policies.

Please answer Yes, No or Unsure in response to each question to the best of your knowledge and belief. If you answer Yes or Unsure to any of the questions, please provide a detailed explanation on a separate sheet of paper.

Answering Yes or Unsure to any of the questions will not result in disqualification for serving as a peer reviewer. The responses to the questionnaire will only be used to help RTI International ensure a balanced, unbiased group of peer reviewers. Responses will not be publicly released without consent of the candidate. However, if you are selected to serve on the peer review panel, RTI International will include the signature page as part of the published peer review record.

It is expected that the candidate make a reasonable effort to obtain the answers to each question. For example, if you are unsure whether you or a relevant associated party (e.g., spouse, dependent, significant other) has a relevant connection to the peer review subject, a reasonable effort such as calling or emailing to obtain the necessary information should be made.

Conflict of Interest Questions

1. Have you had previous involvement with the development of IPM or Base Case 5.13, which is under review? Yes/No/Unsure

2. Is there any connection between IPM and any of your and/or your spouse's (or other relevant associated party's):

    a. Compensated or non-compensated employment, including government service, during the past 24 months? Yes/No/Unsure
    b. Sources of research support and project funding, including from any government, during the past 24 months? Yes/No/Unsure
    c. Consulting activities during the past 24 months? Yes/No/Unsure
    d. Expert witness activity during the past 24 months? Yes/No/Unsure
    e. Other Financial Connections to IPM holding to be reworked as we discussed Yes/No/Unsure

3. To the best of your knowledge and belief, is there any direct or significant financial benefit that might be gained by you or your spouse (or other relevant associated party) as a result of the outcome of peer review of IPM 5.13? Yes/No/Unsure

4. Have you made any public statements (written or oral) or taken positions that would indicate to an observer that you have taken a position on IPM or a closely related topic under review? Yes/No/Unsure

5. Have you served on previous advisory panels, committees or subcommittees that have addressed IPM under review or addressed a closely related topic? Yes/No/Unsure

6. Do you know of any reason that you might be unable to provide impartial advice on the matter under review or any reason that your impartiality in the matter might be questioned? Yes/No/Unsure

7. To the best of your knowledge and belief, is there any other information that might reasonably raise a question about whether you have an actual or potential personal conflict of interest or bias regarding the matter under review? Yes/No/Unsure

Conflict of Interest Analysis and Bias Disclosure Form Signature Page

Please sign below to certify that:

1. You have fully and to the best of your ability completed this disclosure form,
2. You will update your disclosure form promptly by contacting the RTI International peer review facilitator if relevant circumstances change,
3. You are not currently negotiating new professional relationships with, or obtaining new financial holdings in, an entity (related to the peer review subject) which you have not reported, and
4. This signature page, based on information you have provided, and your CV may be made public for review and comment.

Signature ______________________________________

Date____

(Print name)____________________________________

APPENDIX B
PEER REVIEWER RESUMES

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Professional Preparation

Carnegie Mellon University	Civil and Environmental Engineering Engineering and Public Policy	B.S., 1997
University of Wisconsin, Madison	Economics	M.S., 2006
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Appointments

Center Fellow, Resources for the Future	2007 – present
Independent Contractor	2006 – 2007
Project Assistant, University of Wisconsin, Madison	2005 – 2006
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Research Assistant, Resources for the Future	1997 – 2000
Environmental Engineer, Corning, Inc.	1996

Selected Recent Publications

“The Costs and Consequences of Clean Air Act Regulation of CO2 from Power Plants” 2014. *Annual Economic Review: Papers and Proceedings*. 104(5), 557-562. with D. Burtraw, J. Linn, K. Palmer.

“Designing by Degrees: Flexibility and Cost-Effectiveness in Climate Policy” 2014, February. RFF Discussion Paper 14-05.

“Reliability in the Electricity Industry under New Environmental Regulations” 2013, *Energy Policy*, w. D. Burtraw, K. Palmer, B. Beaseley, M. Woerman.

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“A New Look at Residential Electricity Demand Using Household Expenditure Data,” 2010, November. RFF Discussion Paper 10-57. with H. Fell, S. Li.

Awards and Fellowships

Outstanding Civil Engineering Student, Carnegie Mellon University, 1997
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EDUCATION

S.M., Technology and Policy, 2008. Massachusetts Institute of Technology.

- Focus area in Environmental Policy and Economics
- Thesis title: "The Effects of Interactions between Federal and State Climate Policies: Implications for Federal Climate Policy Design"
- Completed coursework at Harvard Law School (Environmental Law), and Kennedy School of Government (Analytic Frameworks for Policy)

B.A., *summa cum laude,* Economics and Environmental Studies, 2000. Middlebury College.

PROFESSIONAL EXPERIENCE

Associate Director for Energy and Environment
Bipartisan Policy Center Energy Project (formerly National Commission on Energy Policy)
Washington, DC. October 2009 – present.

- Led BPC's Electric Grid Initiatives, including engagement and negotiations with task force members, preparation of recommendations and final reports, and outreach to stakeholders and policymakers
- Led modeling of power sector/energy system impacts of a variety of energy and climate policies, including EPA regulations, clean energy standards, cap-and-trade programs, and carbon taxes
- Provided legislative and analytical support to Senate Energy and Natural Resources Committee staff and individual congressional offices
- Conducted outreach to DOE, FERC, EPA congressional offices, and industry associations in support of BPC policy recommendations

Consultant, Environment Group
NERA Economic Consulting. Boston, MA. September 2008 – September 2009.

- Advised private and public sector clients on climate policy design and the economics of environmental regulations

Researcher
MIT Center for Energy and Environmental Policy Research. Cambridge, MA. June 2007 – August 2008.

- Estimated CO_2 abatement in the EU Emissions Trading Scheme (with Denny Ellerman) for book evaluating the impact of the first phase of the program
- Analyzed UK and Spain power sector response to the EU ETS
- Analyzed the economic and environmental implications of interactions between U.S. state and federal climate policies

Policy Analyst
United States Environmental Protection Agency. Clean Air Markets Division, Program Development Branch. Washington, DC. December 2003 – August 2006.

- Advised EPA officials and management on issues related to design and analysis of cap-and-trade programs
- Conducted economic analysis and developed provisions for major regulatory and legislative cap-and-trade programs, including the Clean Air Interstate Rule, Clean Air Mercury Rule, and proposed multipollutant legislation
- Conducted regulatory outreach to industry stakeholders and state environmental agencies

- Drafted guidance on developing new regional and national strategies for air emissions reductions for Clean Air Act Advisory Committee workgroup

Research Assistant and Senior Research Assistant
Resources for the Future, Washington, DC. September 2000 – November 2003.

- Led economic analysis of health benefits from cap-and-trade programs for the power sector
- Analyzed industrial sector response to carbon tax scenarios
- Constructed model and led economic benefits analysis for report for Maryland Department of Natural Resources on the costs and benefits of fish consumption advisories for mercury
- Drafted portions of RFF report on the use of cost-benefit and cost-effectiveness analysis for valuing health outcomes in policy analysis

Research Assistant
Middlebury College Department of Economics, Middlebury, VT. Spring 2000.

- Led econometric analysis for research (with Jon Isham) on the co-production of community-based water projects

Tutor and Grader
Middlebury College Department of Economics, Middlebury, VT. 1999-2000.

- Ran weekly drop-in help sessions for introductory macroeconomics students
- Graded weekly homework assignments for introductory microeconomics students

HONORS AND AWARDS

Gold Medal for Exceptional Service, U.S. EPA, 2006.

Bronze Medal for Commendable Service, U.S. EPA, 2005.

Scott A. Margolin ‘99 Environmental Studies Award for best demonstrating integrated study of the physical and human environments, Middlebury College, 2000.

Department of Economics Thesis Prize, Middlebury College, 2000.

Phi Beta Kappa, Middlebury College, 2000.

New England Small College Athletic Conference All-Academic, 1999, 2000.

RESEARCH AND PUBLICATIONS

“Power Sector Transition: GHG Policy and Other Key Drivers.” With Jennifer Macedonia, Blair Beasley and Stuart Iler. Bipartisan Policy Center. May, 2014.

“A New Organization for Cybersecurity Across the Electric Grid.” *Bulletin of the Atomic Scientists.* April 13, 2014.

“The Administration’s Clean Energy Standard Proposal: An Initial Analysis.” Bipartisan Policy Center Staff Paper. April, 2011.

“Environmental Regulation and Electric System Reliability.” With Jennifer Macedonia, Joe Kruger, and Lourdes Long. Bipartisan Policy Center Staff Report. April 2010.

"After Summit, We Need the Senate to Act." *The Environmental Forum* 27 (2). March/April 2010.

"Overlapping State and Federal Climate Programs: Economic and Policy Considerations." *Climate Policy Economic Insights,* Issue 2. NERA Economic Consulting. April 2009.

"CO_2 Abatement in the UK Power Sector: Evidence from the EU ETS Trial Period." With Denny Ellerman. MIT CEEPR Working Paper WP-2008-010. September.

"The Effects of Interactions between Federal and State Climate Policies." With Denny Ellerman. *In Cap-and Trade: Contributions to the Design of a U.S. Greenhouse Gas Program.* MIT CEEPR. Also released as MIT CEEPR Working Paper WP-2008-004. May.

"Technical Memorandum on Analysis of the EU ETS Using the Community Independent Transaction Log." With Raphael Trotignon. MIT CEEPR Working Paper WP-2007-013. December.

"Overview: Importance of Sources, Chemistry, Technology and Environmental Factors in Setting U.S. Mercury Control Policies." With Sam Napolitano. Paper prepared for China Conference on Mercury, Beijing, China. October, 2005.

"Uncertainty and the Net Benefits of NOx Emissions Reductions from Electricity Generation." 2003. With Dallas Burtraw and Ranjit Bharvirkar. *Land Economics* 79 (3). August.

"The Benefits and Costs of Fish Consumption Advisories for Mercury." 2002. With Paul Jakus and Alan Krupnick. Washington, DC. Resources for the Future Discussion Paper 02-55. October. Also condensed into white paper for National Oceanic and Atmospheric Administration.

CONSULTING REPORTS

Accounting for Differences in the Timing of Emissions in Calculating Carbon Intensity for the California Low Carbon Fuels Standard (with D. Harrison and N. Nichols), prepared for the Renewable Fuels Association, April 2009.

Economic Comments on Nuclear Regulatory Commission DSEIS for Indian Point Energy Center (with D. Harrison and others), prepared for Entergy Corporation, March 2009.

An Economic Evaluation of Borrowing as a Method to Contain Costs in a Greenhouse Gas Emissions Cap-and-Trade Program (with D. Harrison and others), prepared for the Electric Power Research Institute. November 2008.

PRESENTATIONS

"Cybersecurity and the North American Electric Grid: New Policy Approaches to Address an Evolving Threat." Presentation to Washington State Cybersecurity Summit 2. Tacoma, WA. April 2014.

"Capitalizing on an Evolving Power Sector: Policies for a Modern and Reliable U.S. Grid." Presentation to the NASEO Energy Policy Outlook Conference. Washington, DC. February 2014.

"The Regional Impacts of a Clean Energy Standard." Presentation to the RFF/EPA workshop A Federal Clean Energy Standard: Understanding the Important Policy Elements. Washington, DC. July 2011.

"Emissions Trading: Background, Prior Programs, and Implications for a U.S. Carbon Cap-and-Trade Program." Presentation to the ALI-ABA course Clean Air Law, Policy, and Practice, Washington, DC. December 2008.

“Implications of the DC Circuit’s Decision Vacating the Clean Air Interstate Rule.” Presentation to MIT Joint Program on the Science and Policy of Global Change. Cambridge, MA. August, 2008.

“The Clean Air Interstate, Mercury, and Visibility Rules: Implications for Emissions Markets.” Presentation to the Environmental Markets Association 9th Annual Fall Meeting. San Francisco, CA. November, 2005.

“Summary of Economic Analyses of the Clean Air Mercury Rule.” Presentation to the Center for Clean Air Policy, Climate and Air Quality Dialogue, Warrenton, VA. February, 2005.

“The Benefits and Costs of Fish Consumption Advisories for Mercury.” Paper presented at *Camp Resources X*, Wilmington, NC, August, 2002.

Walter D. Short

walterdshort@gmail.com

Professional Experience

2012 – 2014 Retired; consulting on a limited basis on energy modeling issues.

1980 – 2011 National Renewable Energy Laboratory (NREL), Golden, CO, Group Manager, Principal Researcher.
Leadership and management of R&D groups and projects. Technical analysis and modeling of energy technologies, markets and policies. Broad knowledge of energy markets, renewable and energy efficiency technologies and climate change issues. Engineering experience with solar thermal and buildings technologies.

Sample of Accomplishments at NREL:

- Initiated, built up, and led the NREL Energy Forecasting and Modeling Group (EF&M). The group of 20 professionals contributes to analysis for the wind, solar, biomass, geothermal, hydrogen, and vehicles programs as well as cross-cutting analysis for the U.S. Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy.

- Initiator and principal developer of the Regional Energy Deployment System model (ReEDS) of long-term capacity expansion in the U.S. electric sector. ReEDS was the tool used to develop the forecast and costs for the 2008 DOE/AWEA study *20% Wind Energy by 2030*, the 2012 DOE *Sunshot Vision* study, the 2012 DOE *Renewable Electricity Futures* study, the revised NREL *Western Wind and Solar Integration Study* and the *DOE Wind Vision 2014* study.

- Conceptualized and led the development of the Renewable Energy Load Matcher model at NREL to estimate the upper bound on the contribution that wind and photovoltaics can make to U.S. power generation.

- Conceptualized and contributed to the implementation of the Stochastic Energy Deployment System model for the market assessment of energy technologies in all economic sectors under uncertainty. Led team of 6 laboratories and 3 contractors in the model development.

- Identified need, garnered support, hired critical analyst and brought in-house a commercially-available, electricity production cost model, PROSYM, for analysis of the integration of renewables and Plug-in Hybrid Electric Vehicles within specific electric utility systems. This led to the eventual use within the EF&M group of the commercially-available GridView and PLEXOS models.

- Co-chair and co-author of the *Scenarios for a Clean Energy Future*. “This 2000 report for the Interlaboratory Working Group was the subject of two Senate hearings, has been cited in proposed federal legislation, was the subject of an entire issue of *Energy Policy*, and has played a significant role in international climate change debates” (2003 quote from co-chair Marilyn Brown of ORNL).

- Initiated the Renewable Energy Modeling Forum for comparison of the treatment of renewable energy in various market models. This forum morphed into REMAP (Renewable Energy Modeling and Analysis Partnership) which compared model results for various scenarios. Participants included: EIA, RFF, ICF, EPA, NREL, BNL, OnLocation, etc.

1974 – 1980 Senior energy analyst Stanford Research Institute, Menlo Park, CA.

1971 – 1973 U.S. Army, Lieutenant.

Education and Training

M.S., Operations Research, Stanford University, (1974)
B.S., Mathematics, University of Georgia, (1971)

PAUL MICHAEL SOTKIEWICZ

Current Position and Contact Information

Chief Economist, Market Services Division
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, Pennsylvania 19403
E-mail: sotkip@pjm.com
Phone: (610) 666-4351
Mobile: (610) 955-2411

Areas of Expertise

Electricity Market Design, Energy Economics, Environmental Economics, Power System Economics, Regulatory Economics, and Industrial Organization

Education

PhD, Economics, University of Minnesota, 2003
Dissertation: “The Impact of State-Level Public Utility Commission Regulation on the Market for Sulfur Dioxide Allowances, Compliance Costs, and the Distribution of Emissions”
M.A., Economics, University of Minnesota, 1995
B.A. (High Honors), History/Economics, University of Florida, 1991

Academic and Professional Experience

***Chief Economist*, 2010 – present, and *Senior Economist*, 2008-2010, Market Services Division, PJM Interconnection, LLC**

- Lead and support market design initiatives related to Demand Response Compensation in the Energy Market, Shortage Pricing, the RPM Capacity Market, Price Responsive Demand, and any other market design related issues as they arise
- Lead the PJM whitepaper research initiatives related to the impact of environmental regulations on PJM’s markets including potential climate change policy and EPA rulemakings, transmission cost allocation, and other timely relevant topics
- Report to the PJM Board Competitive Markets Committee on market performance and special topics that highlight recent events or future impacts reading PJM’s Energy, Capacity, and Ancillary Services Market
- Support State Government Policy, Federal Policy, and Member Services outreach on topical issues facing PJM, PJM members, state and federal regulators, and state legislatures and Congress.
- Lead and support strategic analysis of relevant commodity market, macroeconomic, and environmental policy trends that affect PJM’s Energy and Capacity Markets

***Director*, 2010 – present, Board of PJM EnviroTrade, LLC**

- Developed the analytical auction model to perform a single auction for solar renewable energy certificates (SRECs) with differing state eligibility requirements across multiple jurisdictions
- Guided strategic direction of PJM EnviroTrade

***Independent Consultant*, 2006 - 2007**

- Provided energy, environmental, and regulatory and government agencies in the United States and globally.
- Supported the Florida Department of Environmental Protection implementation of the EPA Clean Air Interstate Rule in 2006, as well as litigation defense of the rule implementation through emissions compliance cost modeling and direct testimony as an expert witness during litigation.

- Independent expert reviewer for the Belize Electricity Commission in its 2007 initial decision on the Annual Review Proceeding for Belize Electricity Limited examining the logic and robustness of the existing tariff methodology ranging from rate accounts to rate design, cost allocation, and prudence decision regarding purchased power contracts.
- Wholesale electricity market design training and advice for the Electricity Regulatory Authority of Vietnam in 2007 covering energy, ancillary service, and capacity market design fundamentals as well as market design experience from the United States, Europe, and Latin America.

Director of Energy Studies, **Public Utility Research Center, University of Florida, 2000-2008**

- Responsible for conducting regulatory training seminars in electricity for the PURC/World Bank Training course conducted twice yearly.
- Develop and deliver training and advising for energy regulators in Latin America and the Caribbean, Africa, and Southeast Asia as well as in the United States.
- Community and Industry outreach activities throughout Florida on Energy related issues.
- Research, analysis, and monitoring of energy markets and energy industry regulation and restructuring.
- Teaching undergraduate courses in the Government Regulation of Business and Managerial Economics.
- Advising doctoral students on their Ph.D. dissertations at the University of Florida and at other universities

Economist**, Office of Economic Policy, 1998-1999 and Office of Markets, Tariffs, and Rates, 1999-2000**
Federal Energy Regulatory Commission.

- Performed market design analysis for filings from Independent System Operators (ISOs), with an emphasis on the New York Independent System Operator (NYISO) and California Independent System Operator (CAISO) markets
- Briefed Commission staff on aspects of ISO market designs, implementation, and current issues.
- Wrote technical inserts for Commission orders.
- Monitored electricity markets including centralized ISO markets and bilateral markets.
- Conducted applied research on electricity market design for energy and ancillary service markets.
- Performed Merger analysis

Instructor**, Department of Economics, University of Minnesota, 1992-1998**

- Taught large lectures of Principles of Microeconomics and Principles of Macroeconomics. In addition to preparing lectures, exams, and assignments, managed a staff of teaching assistants and graders.
- Taught small classes of Principles of Microeconomics, Intermediate Microeconomics, Environmental Economics and Public Economics. Advised undergraduate students' Senior Projects.
- Member of the department committee that helped redesign the Principles of Economics courses to satisfy the University's Council on Liberal Education International Perspectives requirement.
- In 1998 authored Principles of Microeconomics Study Guide for Independent and Distance Learning Program, University of Minnesota.
- Teaching Assistant Coordinator (1995-96) responsible for creating and implementing training seminars for new teaching assistants and graduate student instructors. This included conducting site visits for observation of teaching and coordinating the videotaping of teaching in the classroom.

Instructor**, Department of Economics, Augsburg College, Minneapolis, Minnesota, 1995-1997**

- Taught classes in Money and Banking, Labor Economics and Principles of Microeconomics.

Teaching Assistant, **Department of Economics, University of Minnesota, 1991-1992**

- Led recitation sections for Principles of Microeconomics.

Publications and Book Chapters

Smith, J.C.; Beuning, S.; Durrwachter, H.; Ela, E.; Hawkins, B.; Kirby, B.; Lasher, W.; Lowell, J.; Porter, K.; Schuyler, K.; **Sotkiewicz, P**.; "The Wind at Our Backs", *IEEE Power and Energy Magazine,* Volume 8, Issue 5, September-October 2010.

Holt, Lynne; **Sotkiewicz, Paul M**.; and Berg, Sanford V.; "Nuclear Power Expansion: Thinking About Uncertainty", *Electricity Journal,* Volume 23, Issue 5, July 2010.

Helman, Udi; Singh, Harry, and **Sotkiewicz, Paul**; "RTOs, Regional Electricity Markets, and Climate Policy", in *Generating Electricity in a Carbon Constrained World,* Fereidoon P. Sioshansi, Editor, Academic Press, September 2009.

Holt, Lynne; **Sotkiewicz, Paul**; and Berg, Sanford; "(When) to Build or Not to Build?: The Role of Uncertainty in Nuclear Power Expansion", *Texas Journal of Oil, Gas, and Energy Law,* (3)2, 2008.

Sotkiewicz, Paul M. and Vignolo, J. Mario, "Towards a Cost Causation Based Tariff for Distribution Networks with DG." *IEEE Transaction on Power Systems,* Vol. 22, No. 3, August 2007, pp. 1051-1060.

Sotkiewicz, Paul and Vignolo, Jesus Mario. "Distributed Generation." *The Encyclopedia of Energy Engineering and Technology*, Vol. 1, pp 296-302. Ed. Barney Capehart. New York: CRC Press, Taylor and Francis Group, 2007.

Sotkiewicz, Paul. "Emissions Trading." *The Encyclopedia of Energy Engineering and Technology*, Vol. 1, pp. 430-437. Ed. Barney Capehart. New York: CRC Press, Taylor and Francis Group, 2007.

Vignolo, Jesus Mario and **Sotkiewicz, Paul M**., "Towards Efficient Tariffs for Distribution Networks with Distributed Generation", *Cogeneration and On-site Power Production*, November-December 2006, pp. 67-75.

Jamison, Mark A. and **Sotkiewicz, Paul M**., "Defining the New Policy Conflicts," *Public Utilities Fortnightly*, July 2006, pp. 36-40, 50.

Sotkiewicz, Paul M. and Vignolo, Jesus Mario "Nodal Pricing for Distribution Networks: Efficient Pricing for Efficiency Enhancing DG." *IEEE Transaction on Power Systems*, Vol. 21, No. 2, May 2006, pp. 639-652.

Sotkiewicz, Paul M. and Vignolo, Jesus Mario "Allocation of Fixed Costs in Distribution Networks with Distributed Generation," *IEEE Transaction on Power Systems*, Vol. 21, No. 2, May 2006, pp. 1013-1014.

Sotkiewicz, Paul M., and Lynne Holt, "Public Utility Commission Regulation and Cost Effectiveness of Title IV: Lessons for CAIR." *Electricity Journal* 18(8): 68-80, October 2005.

O'Neill, Richard P., **Sotkiewicz, Paul M**., Hobbs, Benjamin F., Rothkopf, Michael H., and Stewart, William R. Jr., "Efficient Market Clearing Prices in Markets with Non-Convexities." *European Journal of Operational Research*, Volume 164, Issue 1, 1 July 2005, Pages 269-285.

Vignolo, J. Mario and **Sotkiewicz, Paul M**., "Distribution Network Loss Allocations with Distributed Generation Using Nodal Prices." (*Proceedings of the Seventh IASTED International Conference on Power and Energy Systems*, December 1, 2004 Clearwater Beach, FL).

O'Neill, Richard P., Helman, Udi, **Sotkiewicz, Paul M**., Rothkopf, Michael H., and Stewart, William R. Jr., "Regulatory Evolution, Market Design, and the Unit Commitment Problem" *The Next Generation of Unit Commitment Models,* B. Hobbs, M. Rothkopf, R. O'Neill, and H.P. Chao editors. 2001.

Sotkiewicz, Paul M. "Opening the Lines", *Forum for Applied Research and Public Policy, Special Issue on the Role of Public Power in Utility Restructuring,* Summer 2000, pp. 61-64.

Selected Working Papers and Unpublished Manuscripts

O'Neill, Richard P., **Sotkiewicz, Paul** and Rothkopf, Michael. "Equilibrium Prices in Exchanges with Non-convex Bids." PURC Working Paper, January 2006, updated September 2007.

Sotkiewicz, Paul M. and Vignolo, Jesus Mario "The Value of Intermittent Wind DG under Nodal Prices and Amp-mile Tariffs, PURC Working Paper, December 2006.

Sotkiewicz, Paul M. "Cross-Subsidies That Minimize Electricity Consumption Distortions," Working Paper, Public Utility Research Center, University of Florida, September 2003, revised February 2005.

"Price Tests for Entry into Markets in the Presence of Non-Convexities", with R.P. O'Neill, B. Hobbs, W. Stewart, and M. Rothkopf., mimeo December 2003.

Sotkiewicz, Paul M. “Considerations for the Design of Restructured Electricity Markets and Institutions,” Working Paper, Public Utility Research Center, University of Florida, November 2002, revised September 2003.

Helman, Udi and **Sotkiewicz, Paul M**. “Market Design in the Northeastern U.S. Wholesale Electricity Markets: Events and Issues, 1999-Mid 2000”. Mimeo, Office of Markets, Tariffs, and Rates, Federal Energy Regulatory Commission, June 2000.

“Design Issues for Short-Term Electricity and Ancillary Service Markets” Joint with R.P. O’Neill, U. Helman, J. Cardell, B. Hobbs, W. Stewart, and M. Rothkopf. Mimeo, Office of Economic Policy, Federal Energy Regulatory Commission, January 2000.

Grant Awards

2007	Fulbright Senior Specialist Grant in Economics with a specific request for expertise in electricity markets, electricity regulation, and distribution tariff design, Universidad de la República, Montevideo, Uruguay. Grant award $2,800 plus travel expenses.
2007	Principal Investigator, PPIAF/World Bank Grant to conduct two on-site training courses on the regulation of the electric power sector and on independent power producers and power purchase agreements for the Electricity Authority of Cambodia. Grant award $59,900.

Honors and Awards

2006	“Efficient Market Clearing Prices in Markets with Non-Convexities” published in *European Journal of Operational Research* received New Jersey Policy Research Organization Bright Idea Research Award in Decision Sciences.
2003	Transportation and Public Utilities Group, Ph.D. Utilities Dissertation Award for “The Impact of State-Level Public Utility Commission Regulation on the Market for Sulfur Dioxide Allowances, Compliance Costs, and the Distribution of Emissions”
1992-97	Distinguished Instructor, Department of Economics, University of Minnesota
1995-96 1994-95 1993-94 1992-93	Walter Heller Award for Outstanding Teaching of Economic Principles, Department of Economics, University of Minnesota
1991-92	Distinguished Teaching Assistant, Department of Economics, University of Minnesota
1991	Phi Beta Kappa, University of Florida

Ph.D. Dissertations Supervised and Dissertation Committees

2008	Committee Member (unofficial). Joshua David Kneifel, “Essays in Renewable Energy and Emissions Trading”, Department of Economics, University of Florida.
2007	Thesis Director. Jesús Mario Vignolo, “Cost-causality Based Tariffs for Distribution Networks with Distributed Generation,” Universidad de la República Instituto de Ingeniería Eléctrica.
2005	External Examiner. Juan Daniel Oviedo, “Regulation of Regional Monopolies in Natural Gas Markets”, Midi Pyrénées School of Economics, Université de Toulouse I.

Referee and Review Experience

IEEE Transactions on Power Systems

Ecological Economics

Environmental Science and Technology

Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure, prepared for The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II, September 28, 2006 Washington, DC

National Research Council of the National Academy of Sciences report entitled "Changes in New Source Review Programs for Stationary Sources of Air Pollutants", February 2006

California Energy Commission (CEC) Energy Innovations Small Grant (EISG) Program

Energy Journal

Journal of Environmental Economics and Management

IEEE PES Letters

IASTED International Journal of Power and Energy Systems

The Next Generation of Unit Commitment Models B. Hobbs, M. Rothkopf, R. O'Neill, and H.P. Chao editors 2001.

Professional Affiliations

American Economic Association
International Association for Energy Economics
Association of Environmental and Resource Economists

CURRICULUM VITAE

(as of January 1 , 2014)

John P. Weyant

BACKGROUND

ADDRESSES

Room 260 Huang Engineering Center
Stanford University
Stanford, CA 94305-4121
(650) 723-3506

861 Allardice Way
Stanford, CA 94305
(650) 494-3570

PROFESSIONAL INTERESTS

Application of quantitative methods to policy development and strategic planning.

ACADEMIC APPOINTMENTS

STANFORD UNIVERSITY

- Professor – Dept. of Management Science and Engineering (1/2000 – present)
- Professor- Engineering-Economic Systems and Operations Research (9/96-12/99)
- Professor - Department of Engineering-Economic Systems (9/89-8/96)
- Associate Professor - Department of Engineering-Economic Systems (9/84-8/89)
- Senior Research Associate - Department of Operations Research (9/80-8/84)
- Research Associate - Department of Operations Research (6/77-8/80)

EDUCATION

HARVARD UNIVERSITY:

- Postdoctoral Fellow - John F. Kennedy School of Government (1976-7)
- Research Topic: Quantitative Models in Energy Policy

UNIVERSITY OF CALIFORNIA, BERKELEY:

- Doctor of Philosophy - Management Science (1976)
- Minor Fields: Economics, Operations Research, Organization Theory

RENSSELAER POLYTECHNIC INSTITUTE:

- Master of Science in Operations Research and Statistics (1971)
- Master of Science in Management (1970)
- B.S./M.S. in Aeronautical Engineering and Astronautics (1969/70)

RESEARCH EXPERIENCE

STANFORD UNIVERSITY

PROGRAM ON INTEGRATED ASSESSMENT MODELING DEVELOPMENT DIAGNOSTICS AND INTERCOMPARISONS: Cutting edge research on uncertainty, technology dynamics, and fine scale climate impacts, model diagnostics development, and scenario ensemble construction for IAM community- Lead PI (20 PIs at four institutions) 8/10-

ENERGY MODELING FORUM: The EMF conducts systematic comparative studies of energy-economic models applied to policy problems of current interest.
Director (9/84-present)
Executive Director (J.L. Sweeney, Director): 1/83 - 8/84
Deputy Director (J.L. Sweeney, Director): 12/79 – 12/82
Associate Director (J.L. Sweeney, Director): 8/78 – 11/79
Research Staff (W.W. Hogan, Director): 6/77 – 11/79

SNOWMASS SUMMER WORKSHOPS ON INTEGRATED ASSESSMENT OF CLIMATE CHANGE: Inter-disciplinary workshops on critical issues for integrated assessment - 6/95-

PRECOURT INSTITUTE FOR ENERGY EFFICIENCY:
Deputy Director (J.L. Sweeney, Director): 9/07-present

GLOBAL CLIMATE AJND ENERGY PROJECT
Staff (Lynn Orr, Director): 9/02-9/06

GENERAL MOTORS COLLABORATIVE LABORATORY ON WORK SYSTEMS
Co-Director (With Arthur Veinott): 9/00-9/03

INTERNATIONAL ENERGY PROGRAM: The IEP conducted studies on international energy policy issues of current interest.
Research Staff (A.S. Manne, Director). 7/81 – 8/85
Research Staff (H.S. Rowen, Director): 9/77 - 6/81

COMBINING ENERGY MODELS PROJECT: The CEM project attempted to develop a set of rules for the combination of energy models of different types.
Research Staff (W.W. Hogan & L.J. Lau, Principal Investigators): 8/77 - 4/81

HARVARD UNIVERSITY

ENERGY AND ENVIRONMENTAL POLICY CENTER: 4/76 - 6/77

.

RAND CORPORATION

Air Force Energy Problems (for J.R. Gebman): 6/75 - 3/76
Air Force R&D Planning (for G.K. Smith): 6/74 - 9/74
Air Quality Modeling (for J.R. Gebman): 6/72 - 9/72
Aerodynamics Computer Module (for G.K. Smith): 6/70 - 9/70

U.C., BERKELEY

ENERGY & RESOURCES PROGRAM:
Post Graduate Researcher (J.P. Holdren, Director): 9/74-6/75

OPERATIONS RESEARCH CENTER:
Postgraduate Researcher (R.C. Grinold, Director): 10/72-12/73

RENSSELAER POLYTECHNIC INSTITUTE
URBAN & ENVIRONMENTAL STUDIES PROGRAM:
Graduate Assistant (W.A. Wallace, Director): 1/71 - 9/71

TEACHING EXPERIENCE

STANFORD UNIVERSITY
COURSES TAUGHT:
Energy Policy and Strategy Modeling (EES 283 & EES&OR 483 & MS&E 473) 1979 – 2001
International Environmental Policy (MS&E 92Q): 2001-present
Policy and Strategy Analysis (MS&E 190): 2006-
Public Policy Analysis (MS&E 290): 2000-2006 (with William Perry)
Climate Policy Analysis (MS&E 294): 2004-present
Energy Policy Analysis (MS&E 295): 2005-present

Department of Management Science & Engineering

Seminar on Business & Technology
Department of Engineering-Economic Systems 1987 - 1993
Models and Applications of Operations Research in Society (O.R. 50/150)
Department of Operations Research 1979-1980

Contingency Planning - The World Oil Market
(O.R. 348 A, B, and C, with A. S. Manne)
Department of Operations Research 1981 - 1982

Seminar in Energy/Economic Modeling
(Econ 360ABC, with L.J. Lau and H.G. Huntington)
Fall 1983, Winter & Spring 1984

Financial Decisions, IE 235
Department of Industrial Engineering
Winter 1990, Fall 1990, Winters 1993, 1994 &5

DISSERTATION COMMITTEES (Total - 168; Principal Adviser - 39):
Principal Advisees (Completed Only)
Gregory Hamm (Engineering-Economic Systems - 1986)
Xia Shi (Engineering-Economic Systems - 1989)
Douglas Robinson (Engineering-Economic Systems - 1990)
Peter Lilienthal (Engineering-Economic Systems- 1991)

Hean-Lee Poh (Engineering-Economic Systems -1991)
Sylvia Kwan (Engineering-Economic Systems - 1994)
Eric Johnson (Engineering-Economic Systems - 1994)
Ming-Fai Sit (Engineering-Economic Systems - 1994)
Elisabeth Browne (Engineering-Economic Systems - 1995)
Thomas Hoff (Engineering-Economic Systems and Operations Research - 1996)
Robert Earle (Engineering-Economic Systems and Operations Research - 1996)
Chi-Peng Chu (Engineering-Economic Systems and Operations Research - 1996)
Shu-Cheng Liu (Engineering-Economic Systems and Operations Research - 1997)
Enrique Garza-Escalante (Eng.-Economic Systems and Operations Research- 1998)
Quingxuan Meng (Engineering-Economic Systems and Operations Research - 1998)
Michael Hsu (Engineering-Economic Systems and Operations Research - 1999)
Akira Maeda (Engineering-Economic Systems and Operations Research - 1999)
Karen (Cushing) Sepucha (Eng.-Economic Systems and Operations Research - 1999)
Karl Knapp (Eng.-Economic Systems and Operations Research – 1999)
Kevin Zhu (Eng.-Economic Systems and Operations Research - 1999)
Antje Kann (Eng.-Economic Systems and Operations Research – 2000)
Wenlong Weng (Eng.-Economic Systems and Operations Research – 2001)
Michelle Freed (Eng.-Economic Systems and Operations Research – 2001)
John McConnell (Eng.-Economic Systems and Operations Research – 2001)
Erin Baker (Eng.-Economic Systems and Operations Research – 2002)
Jochen Kleinknecht (Eng.-Economic Systems and Operations Research - 2002)
Fehmi Ashaboglu (Eng.-Economic Systems and Operations Research – 2002)
Kazuhiro Ninomiya (Management Science and Engineering – 2003)
Tao Yao (Management Science and Engineering – 2005)
Albert Whangbo (Management Science and Engineering – 2005)
Geoff Blanford (Management Science and Engineering – 2006)
Oytun Eskiyenenturk ((Management Science and Engineering – 2006)
Leslie Holmes Hummel (Interdisciplinary Program on Environment and Resources-2006)
Katherine Calvin (Management Science and Engineering-2007)
Dhruv Sharma (Management Science and Engineering -2010)
Nikit Abhyankar (Interdisciplinary Program on Environment and Resources -2013)
Danny Cullenward (E-IPER & JD Stanford Law School- 2013)
John Bistline (Management Science and Engineering - 2013)
Jordan Wilkerson (Management Science and Engineering – 2014)

ENGINEER'S THESIS ADVISEES (3):

Teodoro Myslabodski (Operations Research)
Anousheh Alamzad (Engineering-Economic Systems)
Vincent Lui (Engineering-Economic Systems and Operations Research)

OTHER ACTIVITIES

PROFESSIONAL SOCIETY MEMBERSHIPS (Year Joined)

The Operations Research Society of America (1974)
The Institute of Management Sciences (1976)
The American Economic Association (1976)
The International Association of Energy Economists (1978)
The Association for Public Policy Analysis and Management (1979)
The Econometric Society (1981)
The Academy of Political Science (1981)
The Mathematical Programming Society (1982)
The American Statistical Society (1983)
The Association of Energy Engineers (1984)

JOURNALS REFEREED

Energy Economics (Editor in Chief 2002-)
Interfaces (Area Editor: Public Policy 1988 - 1991)
Petroleum Management (Editorial Advisory Board 1984 - 1991)
Operations Research (Associate Editor 1983-1987)
The Energy Journal (Editorial Board 1985 - present)
Environmental Modeling and Assessment (Editorial Board 1995-present)
Management Science
Resources and Energy
International Studies Quarterly
Resources and Energy
Economic Inquiry
The Journal of Economic Dynamics and Control
The European Journal of Operational Research
The Journal of Policy Modeling
Energy Policy
Policy Studies

CONFERENCE ORGANIZATION

Program Chairman: International Association of Energy Economists,
  Sixth Annual North American Meeting, San Francisco, November 1984 (36 Sessions & 5 Plenary Addresses)
Co-General Chairman: International Association for Energy Economics,
  Eleventh Annual North American Meeting, Los Angeles, October 1989
Program Advisory Committee: International Association of Energy Economists
  Seventh Annual North American Meeting, Philadelphia, December 1985
  Eighth Annual North American Meeting, Cambridge, MA, November 1986
  Ninth Annual International Meeting, Luxembourg, July 1988
  Tenth Annual International Meeting, Caracas, June 1989
Individual Sessions Organized at Professional Society Meetings:

Institute for Operations Research and Management Science-17
American Economics Association - 3
International Association for Energy Economics - 8

MAJOR ADVISORY BOARDS AND COMMITTEE MEMBERSHIPS

-N.R.C. Committee on Nuclear and Alternative Energy Systems (1975-77)
-The Institute for the Future - Advisory Board on NSF Interactive Modeling (1978-82)
-Scientists' Institute for Public Information - Oil Emergency Task Force (1980)
-Energy Research Commission of Sweden-Research Program Evaluation Comm. (1982-84)
-Office of Technology Assessment - Advisory Board on U.S. Gas Supply (1983-84)
-Chairman: E.P.A. Peer Review Panel on Acid Deposition Research (1983-87)
-Advisory Board - Electric Power Research Institute Visibility Valuation Project (1983-87)
-National Academy of Sciences: Committee on The Gas Research Institute (1985-87)
-California Public Utilities Comm.-Advisory Board on Utility Model Reviews (1986-88)
-Advisory Board on Utility Model Reviews, California Public Utilities Commission (1986-89)
-Peer Reviewer Final Assessment Report-National Acid Precipitation Assessment Prog. (1990)
-Secretary of Energy Advisory Board (1992-1993)
-Nat. Renewable Energy Lab., Analytic Studies Division Advisory Board (1993-1996)
-Convening Lead Author: Intergovernmental Panel on Climate Change Second Assessment Report – Working Group III on Economic and Social Dimensions (1993-1995)
-Lead Author: The Contribution of the Social Sciences to Global Climate Change Policy: A State of the Art Report (1993-1996)
-Collaborating Faculty Member: International Institute for Applied Systems Analysis (1994-)
-Review Panel, Program on Climate Change, Division of Energy Research, U.S. Department of Energy (1994-)
-Director: Snowmass Workshops on Climate Change Impacts and Integrated Assessment (1995-)
-Advisory Board, Consortium on International Earth Sciences Information Network (1995-2002)
-Participant, Forum on Global Change, Joint Program on the Science and Economics of Global Change, Massachusetts Institute of Technology (1995-).
-Lead Author, Intergovernmental Panel on Climate Change, Special Report on Emissions Scenarios (1996-1998).
-Advisory Board: Yale/National Bureau of Economic Research Program on Economics and Policy Issues in Global Warming National Science Foundation Center (1996-)
-Adviser: National Institute for Environmental Studies, Japan (1997-)
-Chairman: External Review Panel- Electric Power Research Institute: Environment Division
-Coordinating Lead Author, Intergovernmental Panel on Climate Change, Third Assessment Report, Working Group II on Climate Impacts and Working Group III on Climate Change Mitigation (1998-2001).
-Independent Expert Review Panel, Energy Information Administration Report on <u>Likely Costs and Energy Sector Impacts of the Kyoto Protocol on Climate Change Policy</u>, Report Prepared for the U.S. House of Representatives Committee on Science (1998).
-Chairman, Lawrence Berkeley Laboratory, Director's Review Panel, Environmental Energy Technologies Division (1998).
-Co-founder, The Boathouse Group of Climate Negotiators fro the twelve largest carbon emitting

countries (2003-).
-Review Editor, Intergovernmental Panel on Climate Change, Assessment Report Number Four, (2004-2007).
- American Statistical Association Advisory Board for the Energy Information Administration, U.S. Department of Energy (2006-)
-California Air Resources Board, (ARB) -Economic and Technology Advancement Advisory Committee (ETAAC) (2007-).
- World Bank – Advisory Board for Latin American and Carribean Region, (2007-)
- World Bank – Academic Advisory Board for World Development Report – 2010.
-National Academy of Sciences America's Climate Choices Study
- Review Editor, Inter-Governmental Panel on Climate Change.
- Chairman, Scientific Advisory Board, European Commission's AMPERE Project on Integrated Assessment Model Diagnostics.
-Steering Committee, Latin American Modeling Project
-Member: Economic and Technology Advancement Advisory Committee to the California Air Resources Board on Implementation of AB32 the Climate Solutions Act of 2006
- American Statistical Association Review Committee, the Energy Information Administration – U.S. Department of Energy (2006-2012).
-Review Panel, Program on Integrated Assessment of Climate Change, Division of Energy Research, U.S. Department of Energy.
-Co-Editor in Chief , <u>Energy Economics</u>
-Editorial Board, <u>The Energy Journal</u>
-Chairman: Steering Committee of the Integrated Assessment Modeling Consortium (IAMC)-55 International Member Institutions.
-Collaborating Faculty Member: International Institute for Applied Systems Analysis.
-Participant, Forums on Global Change, Joint Program on the Science and Economics of Global Change, Massachusetts Institute of Technology.
-Adviser: National Institute for Environmental Studies, Japan.
-Member, Steering Committee, The International Project on "Developing a Technology Strategy for Dealing With Climate Change," Lead by Pacific Northwest National Laboratory for An International Consortium of Government and Industry Sponsors.
-Chairman, Scientific Advisory Board, European Commission's ADVANCE Project on Cutting Edge Research for Integrated Assessment Modeling.
- Biological and Environmental Research Advisory Board, Office of Science, U.S. Department of Energy (2014-2016).

OTHER UNIVERSITY ACTIVITIES

Freeman Spogli Institute for International Studies
SENIOR FELLOW (1998-)

Woods Institute for the Environment
SENIOR FELLOW (2007-)

Precourt Institute for Energy
SENIOR FELLOW (2010-)

Northeast Asia - United States Forum on International Policy
FELLOW (1982 - 1985)

Engineering Library Committee
MEMBER 1986-1995
CHAIRMAN 1988-1991

University Committee on Libraries
MEMBER 1988-1991

OFFICES IN PROFESSIONAL SOCIETIES

President, Northern California Chapter-International Association of Energy Economists
Vice President, U.S. Institute of Energy Economics
Vice President, International Association for Energy Economics
Chairman, IAEE Nominating Committee for 1989
Selection Committee – Best Paper in the Energy Journal for 1997 - 1998

CONSULTING

Rand Corporation
Electric Power Research Institute
U. S. Department of Energy
Environmental Protection Agency
Pan Heuristics
Applied Decision Analysis
Science Applications, Inc.
Charles River Associates
U.S. Arms Control and Disarmament Agency
United States Synthetic Fuels Corporation
National Acid Precipitation Assessment Program
California Energy Commission
Federal Trade Commission

HONORS and AWARDS

STANFORD UNIVERSITY

Adelman Frankel Award for 2008, U.S. Association for Energy Economics, for Unique and Enduring Contributions to the Field (Ninth Individual Award in International Competition)

Nobel Peace Prize, 2007, Significant Contributions to the Intergovernmental Panel on Climate Change Award.

HARVARD UNIVERSITY:

POSTDOCTORAL FELLOW, National Science Foundation, Harvard University (1976-1977)

UNIVERSITY OF CALIFORNIA, BERKELEY:

REGENTS FELLOW (1972-1974)
DISTINCTION Plus, Ph.D. Qualifying Examination in Economic Theory (June 1973)
DISTINCTION Plus, Ph.D. Qualifying Examination in Management Science (Dec. 1973)

PUBLICATIONS

JOURNAL ARTICLES (last five years only)

Allen A. Fawcett, Katherine V. Calvin, Francisco C. de la Chesnaye, John M. Reilly, John P. Weyant, " Overview of EMF 22 U.S. Transition Scenarios," Energy Economics, Vol. 31, Supplement 1, Pages S198-S211, Available online 28 October 2009.

Leon Clarke, John Weyant, Energy Economics, Introduction to the EMF 22 Special Issue on Climate Change Control Scenarios, Vol. 31, Supplement 1, Page S63,Available online 26 October 2009.

Richard H. Moss, .., J.P. Weyant.., The Next Generation of Scenarios for Climate Chnage Research and Assesment, Nature, Vol. 463, No. 7282, 11 February, 2010, pp 747-756.

D. P. van Vuuren,, James A. Edmonds, Mikiko Kainuma, Keywan Riahi and John P. Weyant (2011) Special Issue: The Representative Concentration Pathways in Climatic Change, Climatic Change:109:1-2, 241 pp. Introduction and Overview paper plus editor of whole volume.

John P. Weyant, Accelerating the development and diffusion of new energy technologies: Beyond the "Valley of Death", Energy Economics, Volume 33, Issue 4,
July 2011, pp. 674-682.

P. A. Matson, T. Dietz…, J. P. Weyant, et al., America's Climate Choices; Advancing the Science of Climate Change, Board on Atmospheric Sciences and Climate, National Academy of Sciences, 2010.

Competing or Coordinating: IT R&D Investment Decision Making Subject to Information Time Lag (Tao Yao, John Weyant, Baichun Feng*), *Information Technology and Management*, Vol. 12 (3), 213-228, 2011

L.E. Clarke, L.E., V. Krey, J.P. Weyant, Regional energy system variation in global models: results from the Asian Modeling Exercise scenarios. Energy Econ. 34 Supplement 3, S293–S305, 2012.

Bistline, J. E. and J. P.Weyant (2013). Electric Sector Investments under Technological and Policy-Related Uncertainties: A Stochastic Programming Approach. *Climatic Change*.

J. Weyant, B. Knopf, E. De Cian, I. Keppo, and D. van Vuuren, Introduction to the Emf 28 Study On Scenarios For Transforming The European Energy System, Climate Change Economics, Vol. 4, Suppl. 1, 2013. (also, editors of whole special issue volume).

Kriegler E, J.P. Weyant, et al. (2013). The role of technology for achieving climate policy objectives: overview of the EMF 27 study on global technology and climate policy. *Special Issue of Climatic Change*, (forthcoming) (also editors of two volume special issue).

Sugiyama, M., O. Akashi, K. Wada, A. Kanudia, J. Li, and J. Weyant, 2013. Energy Efficiency Potentials in Global Climate Change Mitigation; A comparison of modeling approaches, in Special Issue of *Climatic Change*, forthcoming.

Rose, S., E. Kriegler, A. Popp, and J. Weyant, 2013. Bioenergy in energy transformation and climate management, Special Issue of *Climatic Change,* forthcoming.

Weyant, J.P., Fawcett, A.A., Clarke, L.C. eds. Forthcoming. Energy Modeling Forum 24. *Energy Journal* Special Issue.

Allen A. Fawcett, Leon C. Clarke[*], Sebastian Rausch, John P. Weyant, Overview of EMF 24 Policy Scenarios, *The Energy Journal*, in press.

Clarke, L.C., Fawcett, A.A., McFarland, J., Weyant, Overview of the EMF 24 Technology Scenarios, *Energy Journal, in press.*

APPENDIX C
PEER REVIEW PANEL CHARGE

Peer Review of Integrated Planning Model Formulation

Background

The U.S. Environmental Protection Agency uses the Integrated Planning Model (IPM®) developed by ICF International (ICF) to project the impact of potential emissions policies on the U.S. electric power sector in the 48 contiguous states and the District of Columbia over the 2016-2050 time horizon. IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. EPA uses IPM to evaluate the cost and emissions impacts of alternative policies to limit emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2), and air toxics including mercury (Hg) and hydrochloric acid (HCl) from the electric power sector's operations. IPM's deterministic, linear programming formulation not only supports a large scale model with the required level of detail, but it also allows model runs to be performed, quality assured, and delivered within turnaround times (2-3 days) required by EPA and the many decision makers who use IPM results for policy analysis.

The level of detail of IPM outputs at the state, regional and national adds levels transparency to EPA technical analyses by making it easy for stakeholders and expert reviewers to examine the specific estimated impacts of potential new policies, to evaluate the technical credibility of EPA's projections, and to comment on the consequences of modeled policies.

EPA's Needs for a Power Sector Model

To support periodic policy and regulatory analyses of the electric power sector, EPA needs to routinely access a model of the electric power sector capable of analyzing the projected impact of environmental policies in the 48 contiguous states and the District of Columbia. The model must be able to evaluate the costs and impacts of proposed environmental programs affecting the power sector, such as programs limiting emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon dioxide (CO_2), hydrogen chloride (HCl), and mercury (Hg). The model must be able to provide forecasts of the future impacts of a wide variety of potential environmental policies affecting generation capacity expansion and retirements, electricity dispatch, fuel use, and emission control strategies expected to be adopted in order to meet potential changes in energy demand and environmental, transmission, dispatch, and reliability constraints.

The model must incorporate sufficient engineering, financial and geographical detail, as well as the current status of the power sector, in order to provide EPA the ability to analyze emission control options encompassing a broad array of emission control technologies along with emission reductions through fuel switching, changes in capacity mix and electricity dispatch strategies. The model must be able to capture the complex interactions among the electric power, fuel, and environmental markets.

The power sector model that EPA uses must meet EPA's goals for transparency, scientific integrity, technical accuracy, peer review, and public participation in regulatory development proceedings. One critical component of achieving all these goals is periodic peer review of the power sector model used by EPA. The peer review of the model must follow the procedures and standards of EPA's current policies and guidance on peer review as well as the Office of Management and Budget's *Final Information Quality Bulletin for Peer Review* (2004).[5] Other necessary components of achieving EPA's transparency and public participation goals include the model documentation, input data used by the model, and sufficient model results information (i.e., output data) to support communication and review objectives.

Purpose of Peer Review

In November 2013 EPA released a new base case (designated EPA Base Case v.5.13). This new EPA base case incorporates important structural improvements and data updates with respect to EPA's previous base case version (v.4.10).[6]
Base cases serve as the starting point against which EPA compares potential policy scenarios. Base Case v.5.13 is a "business-as-usual" projection of electricity sector activity that takes into account only those Federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the EPA base case was finalized in August 2013.

This peer review will focus on the use of EPA Base Case v.5.13 in IPM with the intent of obtaining expert feedback on the adequacy of using the base case and IPM to meet EPA's needs for estimating the economic and operational behavior of the power sector under alternative emissions policies over a modeling time horizon of 2016-2050.

Among the goals of the peer review are:

(a) given the scope and intended purposes of EPA's base case v.5.13, evaluate whether the IPM analytical framework, assumptions and applications of data are appropriate for meeting EPA's needs for a policy base case and power sector model to be used to estimate the impacts of emissions policy alternatives;

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[5] EPA's current peer review guidance contained in the *EPA Peer Review Handbook, 3rd Edition* (2006), and the *Addendum to the EPA Peer Review Handbook, 3rd Edition* (2009). Both EPA documents, as well as the OMB Bulletin are available at http://www.epa.gov/peerreview/. EPA is currently completing a new version of the EPA Peer Review Handbook; the 4th edition PRH is scheduled for release in 2014.

[6] The version number (4 or 5) indicates a major update affecting fundamental projection inputs or outcomes (such as fuel resource assumptions or regions). The portion of the version name after the 'dot' (10 or 13) indicates the use of Energy Information Agency's (EIA) *Annual Energy Outlook* (AEO) information (most importantly the AEO demand projections), in this case AEO 2013.

(b) identifying specific strengths, weaknesses, limitations, and errors in the base case formulation;
(c) proposing specific options for correcting errors and fixing or mitigating weaknesses and limitations in the base case formulation;
(d) evaluate whether the parameters of the EPA base case v.5.13 and the IPM model have an appropriate basis (e.g., econometric estimation, published financial and power sector data) that is supported from existing literature.

Topics to be Addressed

1. Identify strengths and weaknesses in the structure of the base case and the model formulation with respect to the following:
   a. Objective function. Are all elements necessary to meet EPA's analytical needs included in IPM's least cost objective function? Are any extraneous or inappropriate elements included in the objective function? Are the different terms within the objective function consistent with each other? Does the objective function account correctly for time and geographical factors?
   b. Constraints. Are all the constraints necessary to meet EPA's analytical needs included? Are there any extraneous or confounding constraints? Are the constraints correctly formulated? Within individual constraints are the terms consistent with each other? Is the sense of the constraint (i.e., ≤,≥,=) correct? Could any constraints be simplified?
   c. Decision variables and their indexes. Are all the decision variables necessary to meet EPA's analytical needs included? Are there any extraneous or confounding decision variables? Are decision variables unambiguously defined? Could any be simplified? Do they correctly represent time and geographical factors?

2. Identify strengths, weaknesses, limitations, and errors in the base case and the IPM formulation representation of:
   a. Power sector operation. Are the base case and IPM's representations of model regions, electricity demand and growth, electricity peak demand, transmission, generation, dispatch, capacity additions, capacity factors, reserve margins adequate to meet EPA's analytical needs?
   b. Generating resources. Are the base case and IPM's representations of existing generating units and new (potential) capacity that the optimization model "builds," differentiations based on plant types (e.g., coal steam, combustion turbine, combined cycle, integrated gasification combined cycle, nuclear, biomass, wind, fuel cells, solar photovoltaic and thermal, geothermal, landfill gas, and repowerings), and capability of reflecting locational variations adequate to meet EPA's analytical needs?
   c. Emission factors and control alternatives. Are the base case and IPM's representations of emission factors, existing controls and available control alternatives available within the model adequate to meet EPA's analytical needs? Are the least-cost retrofit combinations, control differentiations based on pollutant (e.g., sulfur dioxide, nitrogen oxides, mercury, carbon dioxide and hydrochloric acid), and constraints from impacts retrofit sequencing incorporated in the model adequate to meet EPA's analytical needs?

d. Emission policies. Are the base case and IPM’s ability to represent emission policies that are differentiated geographically (e.g., nationally, by state, by region, by specific plants), by policy mechanism (e.g., straight caps, cap and trade with and without banking, seasonal limits, rate limits, tonnage limits), by allowance allocation and processing approach (e.g., with and without flow control, output vs. input allocation), and by pollutant adequate to meet EPA’s analytical needs?
e. Power system finance and economics. Are the base case and IPM‘s handling of general financial assumptions, including costs affecting dispatch, capacity additions and retirements, retrofits, repowerings, differentiations based on investment risk, and externalities adequate to meet EPA’s analytical needs?
f. Fuels. Are the base case and IPM’s representation of fuel supply, demand, and cost information for multiple fuel types and subtypes, different supply and demand regions, and different representations of supply dynamics (e.g., endogenous treatment vs. exogenous fixed price streams), competing fuel demand from non-electricity sectors, and fuel transportation or transmission adequate to meet EPA’s analytical needs?
g. Regional resolution. Is the new regional representation in the base case and IPM (64 US regions plus 11 Canadian regions) appropriate for both representing the power sector and meeting EPA’s needs for emission estimation?

<u>Topics Not to Be Addressed</u>

1. This peer review is not intended to obtain comments on the choice of a deterministic, least-cost linear programming approach for representing the power sector. Given EPA’s choice of this methodology, reviewers are asked to provide expert input on the strengths and weaknesses of the base case and IPM’s linear programming formulation. For example, reviewers are not being asked for comments on discrete, non-linear, stochastic, or other approaches that might have advantages to the chosen deterministic linear programming approach in representing certain aspects of power system behavior. On the other hand, reviewers are being asked for expert evaluation on elements in the base case and model formulation that can be improved within the framework imposed by a deterministic linear programming approach.

2. This is a peer review of the base case and model’s mathematical formulation and structure, not the specific data that is currently used to populate the base case and model. The quality and adequacy of that data will have a major bearing on many of the same questions that apply to the model formulation. However, for purposes of this peer review, panel members are asked to evaluate the formulation assuming that the model will be populated with the best and most comprehensive data available.

APPENDIX D

IPM BASECASE 5.13 PEER REVIEW PANEL MEETING

RTI International - 701 13th St NW Ste 750
September 9, 2014

9:00 am	Q&A with EPA/ICF - Modeling Framework	30 minutes
	• Load Duration Curves	
	• Demand Response Elasticity	
	• Renewables	
10:30 am	Q&A with EPA/ICF - Power System Operation	30 minutes
	• Transmission Constraints	
11:30 pm	Q&A with EPA/ICF – Generating Resources	60 minutes
	• Life Extension Capital Costs	
12:30 pm	Lunch	60 minutes
1:30 pm	Q&A with EPA/ICF –Financial Assumptions	45 minutes
	• Debt Equity Ratios	
2:00 pm	Q&A with EPA/ICF – Coal and Natural Gas	30 minutes
	• Shadow Pricing	
2:30 pm	Panel Discussion	60 minutes
3:30 pm	Consensus Report Development	60 minutes
	• Report Assignments	
4:30 pm	Wrap up	