ICF Economic Drivers of PV Study
Stakeholder Comments and ISO/ICF Responses

Comment #	Comment Topic	Comments	ISO & ICF Response
1.	Summary	The ISO truly appreciates the many thoughtful comments provided by the DGFWG and has posted this matrix as a summary of all 12/15/14 DGFWG discussions and subsequent written comments received. The ISO carefully reviewed every comment and compiled this summary for discussion purposes. ISO has made a good-faith effort to accurately summarize some major comments and recognizes that this summary may not comprehensively capture all comments submitted.	ICF was contracted by ISO-NE to deconstruct PV economics into individual drivers to help inform ISO-NE's 2015 PV forecast process in response to stakeholder feedback that PV economics need to be considered as part of the forecast process. The study helps illustrate the complex interplay of public and private investment and business models commonly involved in PV commercialization. It characterizes the relative importance of economic drivers under standardized assumptions across states & customer types. The study does NOT analyze the cost-effectiveness of Federal, state, or utility PV policies nor make value judgments about the need for, or appropriateness of, such policies. The study assesses how economic drivers may change over time due to changes in assumptions for technology cost and performance, electricity rates, Federal & state incentives, etc.
2.	Study Timeline and Process	The comment timeframe is unreasonably short and unduly limits feedback and suggestions that could improve the effort.	ISO was fortunate to be able to take advantage of available funds and contract with ICF to perform an economic analysis of PV drivers. The analysis is being performed in response to stakeholder requests, and ISO was able to find money in its limited budget for this study. Unfortunately, the study needed to be on a fast track due to year-end budgetary constraints. The ISO appealed to stakeholders to provide timely comments and truly appreciates their responsiveness.
3.	Study Timeline and Process	The study should be provided at least one week prior to this meeting (February 20th) in order for stakeholders to have sufficient time to review and to facilitate substantive discussion at the February 27th meeting.	The final study materials will be posted by mid-February, well in advance of the Feb. 27 meeting date.
4.	Study Timeline and Process	It would be useful for ICF to meet with stakeholders (via conference call) to discuss how their comments were addressed. If comments were not addressed, ICF could explain why. This would be useful to mitigate any stakeholder concerns with results stemming from assumptions with which they may not agree, and could save resources on and around the February 27th meeting.	While the ISO certainly appreciates and understands the concern underlying this question, the ISO's scope of work with ICF does not include provision for this additional round of stakeholder input before the next working group meeting. In addition, the ISO believes that it will be more useful for stakeholders to provide input before or during the Feb. 27 meeting so that they can both review the whole study results and hear from other stakeholders before further commenting on input assumptions.
5.	Study Timeline and Process	Stakeholders requested that the spreadsheet used by ICF to conduct this analysis be made available to the DGFWG. As described by ICF at the December 15th meeting, the cash flow model contains only "simple calculations" using publicly available information. It is not clear what, if any, portions of the spreadsheet are proprietary. If ICF continues to claim that the spreadsheet is proprietary, stakeholders request a detailed identification of which areas are proprietary and why they are so. One of the "Analysis Guideposts" articulated by ICF was transparency. It is difficult to maintain this transparency if calculations are hidden to stakeholders. Lacking provision of the model, the Department requests that an option for DGFWG stakeholders to enter into non-disclosure agreements should be offered in order to gain access to the "simple" spreadsheet model. Again, if this request is denied, ICF and/or ISO-NE clearly articulate what purpose is served by maintaining confidentiality. As a reminder, this study is funded by public ratepayer funds.	The ISO's contract with ICF specifically identifies that the financial model spreadsheet will not be provided. Further, providing the model to the ISO and/or stakeholders would require substantial additional effort, time, and cost for organizing and testing the spreadsheet for external use. Non-disclosure agreements would not reduce the amount of cost involved in making the model available nor would they change the fact that doing so would violate a specific contract provision and fundamentally alter the nature of the scope of work. ICF conveyed at the December 15 meeting that each of the discounted cash flow calculations themselves are conceptually and mechanically "simple." They reflect applying a discount rate to 25 years of revenues or costs for each driver or summary measure. The operation of the entire financial model is not simple. It incorporates all of the drivers (inputs and formulae) and produces simultaneous results for them across 54 use cases (6 states x 3 customer types x 3 project start years). The inputs and methods of the financial model are described in some detail in the narrative report to provide context to stakeholders. The amount of content on methods and assumptions in the report is consistent with the observation that the model is not simple.

ICF Economic Drivers of PV Study
Stakeholder Comments and ISO/ICF Responses

Comment #	Comment Topic	Comments	ISO & ICF Response
6.	Study Timeline and Process	Stakeholders suggested a reasonable deadline of January 5 for stakeholders to provide (further) feedback.	Please see the responses to comments 2-4.
7.	Study Methodology	Stakeholders asked if it would be difficult for ICF to benchmark this analysis against data about PV deployment from the last 5 or 10 years.	This is outside of the scope of the project and would also entail a large amount of extra effort and cost.
8.	Study Methodology	Stakeholders suggested that system sizes should be set to assume 100% of annual on-site electricity consumption for both the residential and commercial size. Stakeholders also suggested that the commercial size be set at 500kW (preferably AC) to provide information that will be most useful to the analysis – differentiating inputs from the residential size category more clearly.	The study will adopt this recommendation for systems to offset 100% of annual on-site electricity (consistent with the limits of a number of state net metering policies) and has adjusted the study accordingly. The study is maintaining the 100 kW_{DC} commercial size for the reasons described in section 3.3.A.in the report. The study design and budget requires that only one commercial system size be evaluated.
9.	Study Methodology	It would be useful for ICF to provide more information with regard to some of the input decisions that have already been made. For example, a fixed system was chosen to be modeled rather than a tracking system, and that a southern exposure was modeled. ICF noted that this choice did not drive the economics of systems in any way. ICF should provide more information with regard to how that decision was made – whether it was an analysis of elasticity's of the price needed using these different assumptions or some other method.	Most PV systems in New England are fixed-tilt systems and, therefore, that mount type was used. The study design and budget allowed for only one mount type per customer type. Tracking systems yield more energy, but are also more costly to install and operate. Anything other than south-facing systems would generally yield less favorable economics, as a significant portion of state policy incentives are energy production-based for physical power output and/or RECs generated.
10.	Study Methodology	Stakeholders asked if PV panels should be installed facing west rather than south which is the current industry practice. Other stakeholders indicated that the southern exposure is better for total PV generation.	Since the existing primary state policy drivers (e.g., SRECs, standard offer rates, and net metering) are often based on energy production, south-facing installations in general should exhibit the most favorable economics for the study. The narrative report has added a note about southwesterly or westerly facing PV systems in response to this stakeholder feedback.
11.	Study Methodology	It is not clear the correlation between PV System Size (Input #1) and the amount of on-site consumption offset by PV output, if any. ICF assumes the level of residential and commercial year 1 PV production equals 66% of annual on-site electricity consumption. At least in Vermont (and we suspect elsewhere), leasing and group net metering options have led to systems being sized at the level of 100% annual on-site electricity consumption (which would lead to a bigger system size). We suggest that this change be made to the assumptions, with the associated implications with regard to the PV systems' peak output, and input #1 (PV System Size).	Please see response #8 on percentage of on-site load offset by PV and system size assumptions.
12.	Study Methodology	Stakeholder suggested the use of a cost of $10,000 per MW DC escalating at CPI for salvage value for utility systems. Most communities require surety or form of decommissioning funds.	The study has now mentioned surety bonds as another potential cost affecting salvage value. The study's assumption about net salvage value was not changed.

ICF Economic Drivers of PV Study
Stakeholder Comments and ISO/ICF Responses

Comment #	Comment Topic	Comments	ISO & ICF Response
13.	Study Methodology	A forecasted inflation rate is likely to be a better indicator of inflation going forward than an average of the last 10 years, which includes unusual values due to the recession. Stakeholders regularly use the risk adjusted Cleveland Fed Estimates of Inflation Expectations (see http://www.clevelandfed.org/research/data/inflation_expectations/ for recent expectations and methodology). We suggest using this rate as a proxy of what “the public currently expects the inflation rate to be.” Please clearly document your final choice and why that is the appropriate inflation rate, addressing why historical data is more reasonable than future projections.	The study will adopt this recommendation. While both historical and expected inflation are reasonable benchmarks, the Federal Reserve Bank of Cleveland expected inflation metric is applied (to assumed PV installed and O&M costs) because it aligns more closely with the U.S. Department of Energy's *Annual Energy Outlook* inflation assumptions for the wholesale and retail electricity prices that are applied in the study. The November 2014 10-year inflation expectations rate from the Federal Reserve Bank of Cleveland of 1.83% is used for reasons described in greater detail in the study. The inflation expectations rate published by the Federal Reserve Bank of Cleveland can change monthly, and has varied from 1.89% to 1.66% between September 2014 and January 2015. Those levels are low, but not unprecedented, by long-run U.S. historic standards. Inflation for Northeast Urban consumers over the past 10 years averaged about 2.5%, and national price inflation since 1913 has exceeded that level on average.
14.	Study Methodology	It is not clear that the inflation rate should be used to re-inflate PV costs at all. Inflation cannot be measured at the single commodity level. It is fundamentally an average of many different prices. If the best information we have is that solar costs are projected to decrease amid an overall inflation rate of 1.83% (the current Cleveland Fed forecast referenced above), then all this means is that all of the other prices for commodities other than PV hardware are expected to increase enough to make the average positive. PV prices still decline in that generally inflationary price environment (just as electronics, or even PV panels themselves, have for the past decade). Conceptually, it isn’t logical to inflate the cost of a single good or service with an escalator that is by its nature a composite of a wide variety of costs. For assumptions such as labor and O&M, this makes more sense because a wide variety of costs are embedded in labor and overhead). Thus, we suggest not re-inflating declining PV hard costs, as proposed by ICF.	Both installed system costs and O&M costs are comprised of a variety of goods and services, including both capital and labor. For example, installed costs include silicon (for solar cells); glass and metal used in modules; inverters; racking; conduit; ballast in some cases; freight; professional services labor from engineers, attorneys, financiers, and managers; installation labor; and permits). The range of costs involved is a reason for using an overall inflation measure. The study has added a note in this regard.
15.	Study Methodology	What about the use of other cost projections from other studies?	The study focused on recent US installed cost data coupled with DOE *Annual Energy Outlook* projections for future cost reductions, increased for inflation. Alternative long-term forecasts of PV installed costs are briefly reviewed in an Appendix to the report.
16.	Study Methodology	Utility-scale installed costs seem unrealistically low – recent prices for utility-scale projects in VT were approximately $2,350/kW.	ISO appreciates receiving this recent data. The study has increased its utility scale installed cost assumption based upon feedback from this stakeholder, as well as those from other states. The study will be using a 2014 installed cost equivalent of \$2,150/kW_{DC} as described in the report.
17.	Study Methodology	Cost for utility-scale projects is too low, with development fee, soft costs, etc. cost is closer to $2.75/watt DC, if not more. As an example, look at SunEdison’s SEC filings.	See comment above. Utility scale costs were increased, but not to this level, based upon the range of feedback received on this question.
18.	Study Methodology	Will this analysis include a section on changes in technology costs and performance over time; and if there would be a look out to a time when potentially state incentives were not needed, i.e. grid parity.	The study assumes incremental technology performance improvement over time, and contains a brief Appendix describing long-run technology cost forecasts. The results also reflect generally decreasing state incentive levels over time (for REC and "other" state incentives) and declining overall Federal policy support. Alternative scenario results are provided with differing assumptions on future levels of certain state incentive programs. Taken together, readers can interpret the baseline and alternative scenario results to help determine the strength of PV economics against a backdrop of generally decreasing government policy support.

ICF Economic Drivers of PV Study
Stakeholder Comments and ISO/ICF Responses

Comment #	Comment Topic	Comments	ISO & ICF Response
19.	Study Methodology	In the course of updating our standard offer ceiling prices recently, we received copy of a contract for O&M services for a 2.93MWDC PV project for $10.63/kW. Developers in Vermont have agreed that this is a reasonable estimate of costs. The Department suggests this O&M cost be used for this study for utility scale costs (the contract may be able to be provided as support for this assumption, however given the short timeframe for these comments permission to provide the contract with these comments was not obtained. Please contact the Department if this is necessary). Given that the O&M cost assumptions for utility scale projects appears to be overstated, we suggest making similar adjustments to residential and commercial scale size categories. We may have more information on smaller systems available; however it was not accessible given the short comment window.	This practical and contemporary project input is appreciated. However, for consistency across states and because the data are drawn from a wider pool of projects, the study's assumptions on O&M costs have not been changed. The study does now refer to Sustainable Energy Advantage's O&M cost modeling (with its multiple sub-categories of O&M) for all PV size classes in Rhode Island if readers wish to have another formal perspective on this issue. In general, O&M costs, even at the study's levels which are higher than those suggested by the stakeholder, are not a large driver of PV economics. Individual O&M contracts often differ in the amount of coverage and may not cover all O&M elements, such as insurance.
20.	Study Methodology	It is not clear from where the assumption is derived that inverters are 6% to 10% of a PV project's original cost. The Department has seen projects with inverter costs within that range. We suggest that using 8% is appropriate – the mid-point of the range rather than the top end of the range. Full documentation of the derivation of the assumption and justification for using the high point of a range, if that assumption remains, should be provided.	The study assumption has been adjusted to be the midpoint (8%) of the range.
21.	Study Methodology	ITC too aggressive for IPP projects. A healthy tax credit investment would be 1.3 times ITC with preferred payout over the first 5+ years.	The study does not break out tax equity from sponsor equity investors. However, in practice, such investors do have different investment return needs and horizons, and their project risk profiles differ. The study reviews projects on a holistic (combined) rate of return basis.
22.	Study Methodology	Our experience shows that the project debt/equity structure makes a large difference in the payback and cash flows necessary to encourage PV development. While the 50/50 debt/equity ratio is reasonable for modeling purposes, stakeholders suggest that ICF describe the impact of changing the debt/equity structure for projects.	ICF ran alternative debt calculations and has described their results in a footnote in the report in response to this comment. Those alternative scenarios are 20% debt with a 15-year loan, 80% debt with a 15-year loan, and 50% debt with a 10-year loan.
23.	Study Methodology	Debt is closer to 10 years on weighted average. Banks in MA as an example do 10 years. I agree one can back leverage after 10 years and note that the revenues for years 11 and on are much less especially if Class 1 REC's tank due to hydro by wire.	See response above. The study added a 10-year loan scenario result in a footnote in response to this question.
24.	Study Methodology	I don't think 5% discount is practical, debt is higher this 5% discount provides lower leveraged IRR. In addition, no investment takes place at 5%. Capital providers will invest in other sectors.	The general analysis assumption is a 10% discount rate. The following explanation of the 5% discount rate is offered in the report and with the intention of being consistent with the stakeholder's comment: An alternative 5% discount rate is also applied in this analysis. This lower discount rate can be seen as representing the investment perspective of entities with less aggressive rate of return goals for PV projects (e.g., that ascribe large environmental or societal values to PV projects and/or do not have high-return investment alternatives). This 5% discount rate is much lower than typically required by independent power producers investing equity in utility scale projects or solar developers/financiers investing equity in portfolios of distributed PV projects.
25.	Study Methodology	Have you excluded system interconnection costs?	The installed cost data used are meant to capture all typical costs of system construction, installation, and commissioning, including interconnection costs. Additional land lease payments and transmission or distribution line extensions or upgrades are not assumed to be included.

ICF Economic Drivers of PV Study
Stakeholder Comments and ISO/ICF Responses

Comment #	Comment Topic	Comments	ISO & ICF Response
26.	Study Methodology	Have you included the capacity value of solar or the value associated with deferred investment in transmission?	Capacity payments are not assumed for PV systems due to the fact that they are not obtained currently by the majority of PV systems in New England that correspond to the system sizes analyzed (2 MW_{DC} and under). Capacity market participation by PV owners may continue to increase in the future, but the timing of that participation and the net capacity revenues received are too uncertain to be included at this time. As to deferred investment in transmission, this analysis did not include it because the analysis concentrates on revenue and cost streams that can be realized currently.
27.	Study Methodology	Why are you assuming a 15-year inverter life instead of a 7-year inverter life (that the commenter sees as possibly more customary)?	While the expected life of the current fleet of inverter technologies is uncertain because it has not been in operation long enough to obtain extensive data, inverter manufacturers frequently offer combined basic and extended warranties of 10 to 20 years in total duration. For example, many of Solectria's combined basic/extended warranty packages are for 20 years. 15 years is a reasonable assumption and implies that the inverter will be replaced once during the overall PV system life of 25 years.
28.	Study Methodology	In CT, the appropriate level for the six-year performance-based solar investment program incentive for residential customers for 2015 PV project starts for third-party owned systems can be estimated at the mean of step 6 and step 7 levels because step 5 should expire this month.	The analysis has updated its rates for this incentive based on this stakeholder input.
29.	Study Methodology	Data from the third quarter of 2014 from Vermont for 240 installations that went through our Small Scale Renewable Incentive Program shows $4.29/$watt_{DC}$. We suggest that this lower price be used as the starting point for residential PV installed costs. The average size for these projects was 6.45kW (which more closely aligns with offsetting 100% of annual consumption).	ISO appreciates receiving this recent data and will adopt it as the 2014 value for residential PV systems. That initial value is adjusted for real cost declines and price inflation to arrive at estimates of 2015, 2019, and 2024 installed costs. This suggestion also benefits from being within the range presented in a recent U.S. Department of Energy SunShot report for Connecticut ($4.03/$watt_{DC}$) and Massachusetts ($4.45/$watt_{DC}$) systems of residential size.
30.	State Policy	With respect to project-level state net metering caps, I have been led to believe that at least in MA the state breaks up projects that exceed the cap so that the full project can get net metering treatment. You may want to talk to some folks at the MA EDCs to confirm whether this is an exception to the rule or common place. You may also want to check with EDCs in other states to see if they do anything like this, too.	As the stakeholder mentions, it is common practice to optimize PV projects against the state's project-level net metering caps. That practice is reflected in the study's analysis for that reason. Because this practice of virtual net metering (also called group net metering) is available across New England, the same concept as described above for Massachusetts is applied to the other states for consistency and because, to the extent that virtual net metering is practically achievable (within the specifics of each state's net metering rules and the availability of hosts with suitable loads to offset with PV production), net metering a utility scale project is frequently financially beneficial to its owner.
31.	State Policy	In Vermont, all net metering production is provided the solar credit in addition to the retail rate (with the credit equal to the difference between $0.20 or $0.19 and the utility retail rate for the first 10 years), then the blended retail rate after 10 years. Thus, net metered volumes, as defined here, are 100%. This nuance should be noted, however results from the analysis as structured should remain useful.	The study describes how it applies the Vermont solar net metering credit in the report. Consistent with this recommendation, volumes for customers participating in the solar net metering credit program are bucketed as "net metered volumes."

ICF Economic Drivers of PV Study
Stakeholder Comments and ISO/ICF Responses

Comment #	Comment Topic	Comments	ISO & ICF Response
32.	State Policy	For MA: SREC at auction floor too aggressive, I would use 0.75 to 0.85. Most IPP's hedge and thus SREC is discounted. For RI: It is unclear to me if offtaker, NGrid, is participating in REC. The project itself only receives a fixed PPA rate from NGrid.	For utility scale projects in Massachusetts, achieved SREC prices have been reduced to 80% of the net SREC auction floor based upon this feedback and discussion with other industry participants. Based upon a review of Rhode Island Renewable Energy Growth Program (RE Growth) legislation and discussions with industry experts, the study assumes that RECs are conveyed (sold by the PV project owner) within RE Growth.
33.	State Policy	MA utility projects pay personal property tax and 50% of commercial. I would use $13,500/MW DC escalating at CPI.	The simplified property tax assumption that is applied across the entire study (0.5% of original installed cost per year) remains unchanged. The Massachusetts property tax assumptions have been modified as described in the study based on this feedback, but also discussions with others participating in the Massachusetts market. They reflect ownership of all systems by third-party owners (e.g., solar PPA developers for distributed systems and independent power producers for utility scale systems).
34.	State Policy	For VT: With the passage of Act 127 of the 2012 Vermont Legislative session, a new taxation system was established for PV plants. In short, PV greater than 10 kW in size is subject to a state solar capacity tax of $4/kW as well as state and municipal property taxes (the former based upon the value of the underlying land and the latter based on the Sandia National Laboratories solar valuation model). Systems smaller than 250kW are exempt from sales taxes. ICF should visit http://tax.vermont.gov/pvrsolar.shtml for more specific information on these taxes.	The study has included the state capacity tax for commercial and utility scale systems based upon this information. It has also applied sales taxes to the equipment portion of utility scale systems (which are larger than 250 kW in the study) in the state based on this information.
35.	State Policy	For VT: Net Metering. Although there is generally a cap on net metering of 500kWAC for non-military projects, there are exceptions as noted in the presentation provided by the Department on December 15. These exceptions should not affect the outcome of the study. Renewable Energy Credits: The assumption is correct. The editorial comments on the "seriousness" of the debate and opinions on how that debate will be resolved should be removed from presentations and reports.	The study has removed observations related to debate on the export of Vermont RECs from solar owners participating in state programs to other New England markets.

ICF Economic Drivers of PV Study
Stakeholder Comments and ISO/ICF Responses

Comment #	Comment Topic	Comments	ISO & ICF Response
36.	State Policy	For VT: The investment tax credit for commercial and utility scale projects is available. However, in practice, there are few entities that have availed themselves of this incentive. The "standard offer" program (which is a tranche of the Sustainably Priced Energy Enterprise Development (SPEED) program) provides ceiling prices for solar PV. The most recent filing for avoided costs ceiling prices, which incorporates many assumptions for 2.2MW_{AC} projects that are applicable for utility scale projects that ICF is considering, reflects a price of $0.15543/kWh (including the transfer of Renewable Energy Credits). It should be noted that many projects have offered their resources at prices well below that price. The net metering solar credit was explained at the December 15 meeting, and is contained in 30 V.S.A. §219a. Please contact the Department with any questions with regard to its calculation or implementation.	Thank you for the perspective on the state investment tax credit, which continues to be reflected in the analysis. SPEED standard offer rates for utility scale customers and net metering solar credits have been adjusted, as described in the report, based on information in Vermont's presentation at the December DGFWG meeting and its helpful feedback during the state-by-state review of incentives during that meeting.
37.	State Policy	For RI: On Slide # 39, Other Major State Incentives, Rhode Island is omitted entirely. However, the state's Renewable Energy Fund (deriving funds from both SBC and ACPs) has been giving substantial grants to subsidize new renewable energy projects, especially solar projects. This is an incentive that probably ought to be included. Renewable Energy Growth Program In order to inform your analysis for Rhode Island, referring to your Slide # 45, last bullet point, actual values being contemplated for the DG Growth Program: see Slide # 2 of the Sustainable Energy Advantage's presentation found here: http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2014/38787.pdf . This is approximately what the actual dollar values will be for 2014 for 12 different categories of renewable DG projects: 6 separate categories of solar (by size and ownership); 2 categories for wind; 2 categories for anaerobic digestion; and 2 for hydro. These prices have been steadily dropping in RI over recent years, but these figures are a reasonable guide for what is about to be presented to the PUC.	Based upon this input and a review of the very helpful Sustainable Energy Advantage presentation on the Rhode Island Renewable Energy Growth Program (RE Growth), the study has incorporated RE Growth into its analysis for the duration of that program. The Renewable Energy Fund is not included, as described in the report, because it is mutually exclusive with RE Growth. Eligible Rhode Island solar owners may continue to access the Renewable Energy Fund after the new RE Growth rates become effective later this year (if they choose not to participate in RE Growth) but, given that the study had to select one program or the other to model given its design and the exclusivity of these incentive programs, RE Growth was selected because its capacity goals are larger than may be accomplished under the Renewable Energy Fund.
38.	Rates	Stakeholders asked if ICF had the ability to adjust the retail and wholesale energy rates. Stakeholders cited recent increases in Standard Offer retail rates in Massachusetts, while others responded that it remains uncertain how lasting these increased rates will become.	The study design and budget allows for one set of wholesale and retail rates. Realized rates by customer class by state were preferred because (i) they capture actual consumer behavior (e.g., response to electricity prices in general and specifically in regulated and deregulated energy markets), and (ii) can be uniformly applied on an annual basis to all states.

Comment #	Comment Topic	Comments	ISO & ICF Response
39.	Rates	With respect to forecast retail rates, it is not clear from the data if you are taking into account the distribution companies efforts to decouple distribution charges from consumption and moving them to a fixed charge that can only be avoided by disconnecting from the grid. I raise this observation because their success will push the avoided retail price closer to the wholesale price which will materially impact the economics. In this same area, do the C&I retail prices shown reflect fixed costs spread over consumption or do the C&I prices shown only reflect consumption based pricing? My understanding is that for C&I in CT and MA the vast majority of distribution costs are recovered in the demand charge so it would seem to me that the distribution savings would be captured in the peak demand reduction and not in "self-generation" and thus perhaps C&I prices should be treated and shown as two values, demand and consumption. Lastly, assuming [the above] concern is wrong and all distribution costs continue to be recovered through a price tied to consumption, is PV growing enough to materially push up the distribution price to other customers such that the resulting pricing reinforces the economics to install PV or do EE? And, if so, do your distribution prices reflect this interaction?	The study describes how peak demand charges, which are common among several utilities in New England for commercial (and industrial) customers, may not be fully offset by on-site PV production. The study also discusses how a precise view of PV economics would incorporate an analysis of how fixed charges are not offset by PV production, power factor charges are often not affected, and peak demand charges are usually only partially offset in practice. The study assigns a proxy value (reduction in PV economics) to non-offset peak demand charges in its analysis of commercial customers. It is outside of the study scope to conduct a more detailed review of this issue and to separate peak demand charges, energy charges (round-the-clock, seasonal, or time-of-use), fixed monthly customer charges, and power factor and other charge types from each other. The study, however, has separated "self-generation volumes" from "net metered volumes" (and defined "net metered volumes" as those physically flowing back to the utility on an hourly basis) to illustrate the volumes of PV production that might be financially affected if net metering billing was aggregated on a different basis than it is currently.
40.	Rates	According to the materials provided, Vermont's retail rates are expected to rise in parallel with other states. However, given that Vermont has remained vertically integrated while the remainder of the region is restructured, Vermont remains significantly hedged from the volatility caused by high winter prices. Because of this current advantage, Vermont expects its retail rates to grow (if they grow) at a lesser rate than the remainder of New England, at least in the near term (we are not expecting the significant near term increases in rates that are currently occurring in other states). Indeed, our largest utility recently implemented a rate decrease. The Department recommends ICF make an adjustment to Vermont retail rates that accounts for the structural differences between Vermont and the rest of the region and the likely resulting effects on retail rates.	The study will maintain its current methodology for consistency across states.
41.	Other Studies	How is this analysis different from those done using the National Renewable Energy Lab's (NREL) Cost of Renewable Energy Spreadsheet Tool (CREST)?	This study, and its financial model, is intended to create statewide and customer class wide values under simplifying and standardized assumptions for individual economic drivers of PV in a standard $/kWh output format to inform a specific PV forecasting process, while CREST offers more project-specific and granular analysis and creates outputs in a different manner. Both models consider similar factors and calculate long-term economics of PV investments.
42.	Other Studies	Note that levelized cost of energy (LCOE) is defined differently in other studies and caution against comparing study results to those of other technologies.	A note making this point has been added to the report.

Comment #	Comment Topic	Comments	ISO & ICF Response
43.	Use of Study	How is the ISO planning on using the results of the ICF study in next year's PV forecast?	Stakeholders had previously raised the importance of considering PV economics as part of the forecast process. The use of ICF's results will be a topic of DGFWG discussion in February 2015. The analysis of PV economic drivers can be useful in illustrating the complexities inherent to PV development given the variety of Federal and state policies that are in play. Consequently, the study will serve to further the DGFWG's understanding of the key factors impacting future PV commercialization, and more specifically, assist the DGFWG and the ISO in developing a sense of how much of future PV development rests on particular incentives, thereby helping to inform important forecast elements, e.g., discount factors applicable to longer term forecast projections.
44.	Results	What are the largest (~5-6) individual drivers for PV?	The largest economic drivers of PV (in no particular order) tend to be: system installed cost (i.e., first cost), physical power revenue (wholesale, offsetting on-site electricity loads, net metering), REC revenue, Federal investment tax credit, and Federal depreciation. Several of these were informally mentioned in response to a stakeholder question at the December 15 meeting, and they are formally recorded in the Summary of Results section of the report that is now available. The relative size of the drivers varies for each state, customer type, project start year combination and is provided in table format within the report.
45.	Results	As previously discussed, key drivers are top line and first cost.	See the response to comment 44.Top line revenue (from physical power offset or sold and from RECs) and first cost (installed cost) are certainly among the key drivers.