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February 21, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Filing Center
P.O. Box 1088
201 High Street S.E., Suite 100
Salem, OR 97308-1088

Re: Docket No. PCN 5 – In the Matter of Idaho Power Company's Petition for Certificate of Public Convenience and Necessity.

Attention Filing Center:

Attached for filing in the above-referenced docket is Idaho Power Company's Reply Testimony and Exhibits of Jared L. Ellsworth (Idaho Power/500-507). Confidential copies are being sent via encrypted zip file to the Filing Center and parties who have signed Protective Order No. 22-309.

Please contact this office with any questions.

Thank you,

Alisha Till
Paralegal

Attachments

DOCKET PCN 5 - CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the confidential pages of Idaho Power Company's Reply Testimony of Jared L. Ellsworth on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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I also hereby certify that on February 21, 2023 Idaho Power Company's Reply Testimony of Jared L. Ellsworth was served by USPS First Class Mail and Copy Center to said person(s) at his or her last-known address(es) as indicated below:

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DATED: February 21, 2023

/s/ Alisha Till
Alisha Till
Paralegal

Idaho Power/500
Witness: Jared Ellsworth

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. PCN 5

In the Matter of	)
	)
IDAHO POWER COMPANY'S	)
	)
PETITION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY.	)
	)
	)
	)

IDAHO POWER COMPANY

REPLY TESTIMONY

OF

JARED L. ELLSWORTH

February 21, 2023

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Exhibit List

- Idaho Power/501 **(Confidential)** - Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H
- Idaho Power/502 - Updated BPA Letter to the Region Regarding B2H and Southeast Idaho Load Service (Jan. 9, 2023)
- Idaho Power/503 - BPA B2H Workshop Presentation (Jan. 23, 2023)
- Idaho Power/504 - Maps Identifying BPA Customers and Utility Service Territories
- Idaho Power/505 - Comments from BPA Customers and Stakeholders
- Idaho Power/506 - Resource Adequacy in the Pacific Northwest (Mar. 2019)
- Idaho Power/507 - Princeton Univ., Net Zero America Potential Pathways, Infrastructure, and Impacts (Dec. 15, 2020)

Q. Please state your name and business address.

A. My name is Jared L. Ellsworth and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. Are you the same Jared L. Ellsworth that previously filed direct testimony in this matter?

A. Yes.

Q. What is the scope and purpose of your Reply Testimony?

A. My Reply Testimony will provide an update on the status of negotiations between Idaho Power Company ("Idaho Power" or "Company"), PacifiCorp, and Bonneville Power Administration ("BPA") (collectively, the "Parties"), following execution of the Term Sheet[1] on January 18, 2022, that addressed the Boardman to Hemingway Transmission Line Project ("B2H" or the "Project") project ownership, transmission service considerations, and asset exchanges, including the regional and system wide benefits B2H will provide those areas served by the Parties. I will discuss how the updated cost estimate of the Project continues to support selection of a B2H portfolio as least-cost, least-risk. In addition, I describe how the Project is necessary for the reliability of Idaho Power's transmission supply and concerns about resource adequacy and the Mid-Columbia ("Mid-C") market prices. Finally, I will clarify several items for which Commission Staff or intervenors expressed concerns.

I. B2H PROJECT PARTICIPANTS

Q. You indicated Idaho Power had an update on the status of negotiations between the B2H project participants following execution of the Term Sheet. Please summarize the provisions envisioned under the Term Sheet.

A. The Parties entered into the Term Sheet after over two years of discussions related to next steps associated with the Project. A decade has passed since the Parties signed the

[1] See Term Sheet included as an attachment to Idaho Power's Response to Standard Data Request No. 2. Idaho Power/203, Barretto/447.

Permit Funding Agreement to jointly support permitting and pre-construction activities to develop B2H. Since then, the Parties' capacity needs, strategies, and goals associated with B2H have evolved and thus the Parties negotiated the Term Sheet as the framework for future agreements required between and among the Parties as B2H moved towards pre-construction. Under the Term Sheet, BPA will transition out of its role as a joint permit funding coparticipant and will instead rely on B2H by taking transmission service from Idaho Power to serve its customers.[2] To accommodate this change, Idaho Power will increase its B2H ownership share from 21.21 percent to 45.45 percent by acquiring BPA's B2H capacity.[3]

Q. Have the agreements envisioned in the Term Sheet with respect to the Company's acquisition of BPA's 24.24 percent ownership share of the Project come to fruition?

A. Yes. In January 2023, the Parties reached a major project milestone, concluding negotiations on final agreements that memorialize and effectuate the change in ownership. There are five different agreements specific to Idaho Power and necessary to reflect adjustments to the funding and ownership percentages envisioned in the Term Sheet, all of which are nearly finalized and will be ready for execution. They consist of the: (1) Second Amended and Restated B2H Transmission Project Joint Permit Funding Agreement,[4] (2) Network Integration Transmission Service Agreement ("NITSA") for Goshen Load,[5] (3) NITSA for Idaho Falls Load,[6] (4) Purchase, Sale, and Security Agreement,[7] and (5) point-to-point ("PTP") transmission service agreements.[8] These are

[2] Idaho Power/203, Barretto/469-470 (Term Sheet).
[3] Idaho Power/203, Barretto/470 (Term Sheet).
[4] *See* Idaho Power/501, Ellsworth/1 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H) (summarizing Second Amended and Restated B2H Transmission Project Joint Permit Funding Agreement).
[5] Idaho Power/501, Ellsworth/7 (Draft NITSA Serving Fall River Electric Coop., City of Soda Springs, Lost River Electric Coop., Lower Valley Energy and Salmon River Electric Coop.).
[6] Idaho Power/501, Ellsworth/24 (Draft NITSA Serving City of Idaho Falls).
[7] Idaho Power/501, Ellsworth/37 (Draft Purchase, Sale, and Security Agreement).
[8] Idaho Power/501, Ellsworth/6 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

summarized in Idaho Power/501 and identified therein as Agreements 1, 2, 3, 4, and 11.

Q. When will the agreements be executed?

A. The parties will execute the agreements following BPA's public process,[9] including additional negotiated adjustments, if any, which is a standard administrative decision-making process applicable to all federal agencies and typically concludes within three months of BPA's notice to the region.

Q. Has BPA begun the public process for their proposed new role in the B2H project?

A. Yes. On January 5, 2023, BPA provided public notice via their Tech Forum platform to customers and stakeholders announcing their completion of B2H project negotiations and releasing the customer engagement schedule, identifying dates for the comment period, customer workshop, and an expected final decision in March 2023.[10] BPA released its Letter to the Region formally opening the comment period on January 9, 2023, providing their customers and stakeholders information about the agreements and notifying them of a BPA-hosted workshop on January 23, 2023, to answer questions about the agreements. In addition, BPA explained that customers and stakeholders had the opportunity to comment through February 9, 2023, prior to BPA proceeding with execution of the binding contracts for the Project. BPA's public process is expected to conclude in March 2023 with the issuance of another letter to the region describing its reasoning behind its decision and responding to comments. A copy of BPA's Letter to the Region opening the comment period is included as Idaho Power/502.

Q. What is required of Idaho Power contractually once BPA's ownership share is assumed?

A. BPA's transition out of its role as a joint permit funding coparticipant will require the Second Amended and Restated B2H Joint Permit Funding Agreement, identified as Agreement 1

[9] Idaho Power/501, Ellsworth/1-6 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

[10] Idaho Power/502, Ellsworth/3 (Updated BPA Letter to the Region re: B2H and Southeast Idaho Load Service) (Jan. 9, 2023).

on Idaho Power/501. As contemplated in the Term Sheet, funding and ownership percentages will be adjusted such that the Company will acquire BPA's permitting interest and funding of 45.45 percent of the B2H costs while providing transmission service across southern Idaho to BPA's customers through NITSA's under Idaho Power's Open Access Transmission Tariff ("OATT"), identified as Agreements 2 and 3 in Idaho Power/501.[11] In addition, the Company will reimburse BPA over time for the value of the permitting costs paid by BPA based on achieved milestones.[12]

Q. Will payments received from BPA under the NITSAs reimburse the Company for its increased share of the B2H project?

A. Yes. The yearly load estimates provided by BPA and the resulting forecasted transmission service payments to Idaho Power under the full term of the NITSAs are projected to offset the Company's costs associated with its increased share of B2H to support BPA's usage, and, therefore, Idaho Power's customers will not be harmed by the changes to the arrangement. In addition, as an added protection for customers, BPA has agreed to a security and risk backstop payment in conjunction with the purchase and sale provisions associated with the Company's acquisition of BPA's ownership share of B2H ("Purchase, Sale, and Security Agreement").[13] The Purchase, Sale, and Security Agreement is included as Agreement 4 to Idaho Power/501.[14]

Under the Purchase, Sale, and Security Agreement, Idaho Power will hold, as a security payment, an amount equivalent to BPA's investment in B2H prior to the transfer of its permitting interest to Idaho Power, or the approximately $28 million BPA has paid towards permitting costs to date ("Transferred Permitting Interest").[15] BPA will also pay Idaho Power an additional $10 million ("Seller's Security"), for a total security deposit of

[11] Idaho Power/501, Ellsworth/1 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[12] Idaho Power/203, Barretto/462 (Term Sheet).
[13] Idaho Power/203, Barretto/466 (Term Sheet).
[14] Idaho Power/501, Ellsworth/37 (Purchase, Sale, and Security Agreement).
[15] Idaho Power/501, Ellsworth/47 (Purchase, Sale, and Security Agreement).

$38 million.[16] The Seller's Security will provide assurances that Idaho Power's retail customers are insulated from risk associated with the Company purchasing BPA's share of the Transferred Permitting Interest.

Upon energization of B2H, interest will accrue on both the Transferred Permitting Interest and the Seller's Security at a rate of 3.25 percent.[17] Because the revenue associated with BPA's usage of B2H in the early years of the agreement will be less than the associated annual revenue requirement, Idaho Power will not begin reimbursements of the Transferred Permitting Interest until specific cost recovery milestones are achieved which should mitigate any potential default risk until BPA has fully paid for its share of B2H costs over time.[18]

Q. Please explain why BPA's payments under the NITSAs will not immediately offset the Company's costs associated with BPA's usage of the B2H project.

A. The rate for which BPA will be charged under the NITSAs is based on the network transmission service rates under Attachment H of Idaho Power's OATT.[19] Rates for transmission service are updated in October of each year, based on the previous calendar year's actual financial data. Because of the regulatory lag that exists between when transmission costs are incurred and when transmission rates are updated, under-recovery of revenue requirement amounts associated with the network transmission service provided to BPA will occur in the first few years the NITSAs are in effect. Once all agreements with BPA have been executed, and prior to energization of the Project, the Company will request authorization from the Commission for accounting treatment that will ensure the Company's retail customers are not harmed by the arrangement until such

[16] Idaho Power/501, Ellsworth/47 (Purchase, Sale, and Security Agreement).
[17] Idaho Power/501, Ellsworth/2 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[18] Idaho Power/501, Ellsworth/2 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[19] Idaho Power/501, Ellsworth/2 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

time as cumulative network transmission service revenues received from BPA exceed BPA's cumulative share of the B2H revenue requirement.

Q. Will the Company be responsible for repaying the Transferred Permitting Interest and Seller's Security to BPA?

A. Yes. Repayment of the Seller's Security and all accrued interest related to the Seller's Security will occur within 60 days following energization of B2H.[20] The repayment of the Transferred Permitting Interest plus all related accrued interest will occur starting year eleven following energization of B2H if BPA's total load under the Goshen and Idaho Falls NITSA's for any rolling twelve-month basis averages 400 megawatts ("MW") or more prior to the tenth anniversary of energization ("Repayment Event").[21] Or, in the alternative, if the total load for any rolling twelve-month basis averages 400 MW or more after the tenth anniversary of B2H energization, then the Repayment Event will commence on the next anniversary date of B2H energization.[22]

Q. Are there any additional terms agreed to between Idaho Power and BPA?

A. Yes. The Term Sheet identified other related transactions between the Company and BPA, two associated with necessary transmission service agreements and one related to substation funding. With respect to the transmission service agreements, first, Idaho Power will secure 500 MW of PTP transmission service from BPA from the Mid-C hub to the proposed Longhorn substation, which will provide the Company a direct connection to the Mid-C market with flexible long-term BPA wheeling rights.[23] Second, as identified in the Term Sheet and as a component of Agreement 11 in Idaho Power/501, BPA will redirect its two 100 MW PTP transmission service agreements that it takes from the

[20] Idaho Power/501, Ellsworth/2 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[21] Idaho Power/501, Ellsworth/2 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[22] Idaho Power/501, Ellsworth/2 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[23] Idaho Power/501, Ellsworth/6 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

Company, assigning them to PacifiCorp, a necessary redirect following termination of BPA's existing NITSA with PacifiCorp.[24]

Q. Please describe the agreement required for substation funding.

A. The Parties have also agreed to terms specific to funding of the Longhorn substation, which BPA will own and operate, and where the Project interconnects.[25] The Longhorn Substation Funding Agreement, identified as Agreement 8 in Idaho Power/501, was not required in advance of BPA's public process and has not yet been finalized.[26] However, provisions of the agreement were identified in the Joint Purchase and Sale Agreement ("JPSA") which I will discuss later in my testimony. As a condition precedent to closing of the JPSA, Idaho Power and PacifiCorp must have finalized the agreement between the Parties for funding a portion of the assets at, and directly adjacent to, the Longhorn substation where B2H will connect.[27] The Longhorn Substation Funding Agreement will also describe the use of a facilities charge, or other similar charge, pursuant to BPA's OATT, that will be paid by the Company and PacifiCorp allowing for each party to transact across the Longhorn bus in the future.[28] It will detail the ownership, operation and maintenance of the B2H equipment by Idaho Power and PacifiCorp, including (1) a B2H-related series capacitor at the substation, (2) the B2H shunt line reactors, and (3) any ancillary equipment required to support the B2H series capacitor and shunt line reactors.[29]

Q. Are there any other agreements you have not yet discussed necessary for facilitating Idaho Power's increased ownership arrangement with BPA?

A. No.

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[24] Idaho Power/501, Ellsworth/6 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

[25] Idaho Power/203, Barretto/457-458 (Term Sheet).

[26] Idaho Power/501, Ellsworth/5 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

[27] Idaho Power/501, Ellsworth/112 (Draft Joint Purchase and Sale Agreement).

[28] Idaho Power/501, Ellsworth/5 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

[29] Idaho Power/501, Ellsworth/5 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

Q. As partners in B2H, what agreements are necessary between Idaho Power and PacifiCorp?

A. In addition to the transactions directly related to construction and operation of B2H, under the Term Sheet the Company and PacifiCorp agreed to the exchange of undivided ownership interests in certain transmission assets to provide transmission capacity that better aligns with the current configuration of the parties' respective future needs following the addition of B2H.[30] The JPSA, included as Agreement 5 on Idaho Power/501, facilitates these asset exchanges.[31]

Q. How will the asset exchanges between Idaho Power and PacifiCorp facilitate the objectives of the parties as envisioned in the Term Sheet?

A. The Company agreed to exchange with PacifiCorp assets necessary to allow for (1) the transfer to PacifiCorp by Idaho Power of transmission assets between Midpoint and Borah to facilitate 300 MW of west-to-east capacity,[32] (2) the transfer to PacifiCorp by Idaho Power of transmission assets between Borah and Hemingway to enable an additional 600 MW of east-to-west capacity, increasing from the current 1,090 MW to 1,690 MW,[33] (3) the transfer to Idaho Power by PacifiCorp of transmission assets between Populus, Mona, and Four Corners to allow for 200 MW of bi-directional capacity,[34] and (4) the transfer by PacifiCorp to Idaho Power of an ownership interest in identified Goshen area assets.[35]

Four Corners/Populus Assets. The Company's ownership interest in the Four Corners/Populus assets will include 345-kV transmission lines between the Four Corners, Pinto, Huntington, Camp Williams, Mona, Terminal, 90th South, Ben Lomond, and Populus substations.[36] Consistent with federal processes, the Company and PacifiCorp

[30] Idaho Power/203, Barretto/459-460 (Term Sheet).
[31] Idaho Power/501, Ellsworth/97-98 (Draft Joint Purchase and Sale Agreement).
[32] Idaho Power/203, Barretto/459 (Term Sheet).
[33] Idaho Power/501, Ellsworth/3 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[34] Idaho Power/203, Barretto/459 (Term Sheet).
[35] Idaho Power/203, Barretto/460 (Term Sheet).
[36] Idaho Power/203, Barretto/459 (Term Sheet).

will complete required studies to determine whether recent system upgrades result in a possible increase in existing transmission capacity between Borah and Populus to facilitate Idaho Power's incremental transfer needs associated with this exchange.[37] If determined necessary, the parties will identify revisions to existing agreements, upgrades, modifications, or other options to meet each party's commercial needs between Borah and Populus.[38]

Goshen Area Assets. Under the Term Sheet, the Parties agreed to make best efforts to plan for service to BPA's six preference customers in Southeast Idaho that requires only one leg of network transmission from the BPA transmission system.[39] Idaho Power's ownership interest in the Goshen area assets will enable BPA to serve its loads currently in PacifiCorp's East transmission system with one leg of firm network transmission service from the Company.[40]

Borah/Midpoint West Assets. The transfer by Idaho Power to PacifiCorp of Borah/Midpoint West assets will provide ownership to PacifiCorp on the Company's existing transmission system from Borah/Kinport to Hemingway (east-to-west) and from Midpoint 500 to Borah/Kinport (west-to-east), including 500-kV and 345-kV transmission lines creating a path between the Borah, Kinport, Adelaide, Midpoint and Hemingway substations.[41] In addition, upgrades will be required across the Borah West and Midpoint West paths to facilitate this portion of the proposed asset exchange.[42]

Q. Is Idaho Power requesting approval of these asset exchanges as part of the request in this case?

A. No. The asset exchanges will not be effective until energization of the B2H project which is expected to occur no earlier than 2026. Exhibit A to the JPSA does however identify the

[37] Idaho Power/203, Barretto/459 (Term Sheet).
[38] Idaho Power/203, Barretto/459 (Term Sheet).
[39] Idaho Power/203, Barretto/461 (Term Sheet).
[40] Idaho Power/203, Barretto/461 (Term Sheet).
[41] Idaho Power/203, Barretto/459 (Term Sheet).
[42] Idaho Power/203, Barretto/459-460 (Term Sheet).

assets necessary for facilitating the capacity rights agreed upon and acquired by Idaho Power or conveyed to PacifiCorp.[43] Both the Company and PacifiCorp will request approval of the agreement pursuant to ORS 757.480 and 757.485, detailing the benefits associated with the assets being exchanged and demonstrating the transaction is consistent with the public interest, in a future proceeding.

Q. Have Idaho Power and PacifiCorp contemplated who will be responsible for operations and maintenance of the exchanged assets?

A. Yes. PacifiCorp and the Company will expand the existing Joint Ownership and Operating Agreement ("JOOA"), as amended and restated August 22, 2019, to include operation and maintenance provisions associated with the assets acquired by both parties under the JPSA.[44] In addition, the Second Amended and Restated JOOA, identified as Agreement 6 on Idaho Power/501, will include the ownership, operation, and maintenance provisions associated with B2H.[45]

Q. Are there any additional agreements between the Company and PacifiCorp as envisioned under the Term Sheet?

A. Yes. As described in the Term Sheet, the Company and PacifiCorp will execute the B2H Project Joint Construction Funding Agreement ("Construction Funding Agreement"), which will cover all work necessary to construct B2H.[46] The Construction Funding Agreement, identified as Agreement 7 on Idaho Power/501, will provide definitive terms and conditions by which the parties will jointly support and contribute funds for the procurement, construction, and commissioning of B2H, allowing for energization of the Project by the earliest in-service date needed by the parties.[47] In addition, it appoints

[43] Idaho Power/501, Ellsworth/133-155 (Joint Purchase and Sale Agreement, Exhibit A).
[44] Idaho Power/203, Barretto/460 (Term Sheet).
[45] Idaho Power/501, Ellsworth/4 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[46] Idaho Power/203, Barretto/460 (Term Sheet).
[47] Idaho Power/501, Ellsworth/4 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

Idaho Power as the construction project manager, providing for full power and authority to do all things necessary or proper to develop and construct the Project.[48] Finally, the Construction Funding Agreement will incorporate work associated with the installation of the Midline Series Capacitor substation,[49] which was originally envisioned as a separate funding agreement in the Term Sheet.[50] The Midline Series Capacitor substation is necessary to reduce simultaneous interactions between the Northwest Alternating Current ("AC") Intertie, central and southern Oregon load service, and Path 14 (Idaho to Northwest).[51] The Company expects to execute the Construction Funding Agreement with PacifiCorp in July 2023.[52]

Q. Are there any other construction agreements required for the Project?

A. Yes. Idaho Power and PacifiCorp will, in conjunction with the JPSA, execute two additional construction agreements, the Midpoint 500/345-kV Transformer Project Construction Agreement ("Midpoint Transformer Construction Agreement") and the Kinport – Midpoint 345-kV Series Capacitor Bank Project Construction Agreement ("Kinport Capacitor Bank Construction Agreement").[53] Under the Midpoint Transformer Construction Agreement, the Company will make capital upgrades to the Midpoint 500-kV and 345-kV transmission substations, including a second 500/345-kV transformer bank and 345-kV tie line.[54] Idaho Power will make capital upgrades to the Borah West transmission path under the Kinport Capacitor Bank Construction Agreement, including

[48] Idaho Power/501, Ellsworth/4 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[49] Idaho Power/501, Ellsworth/4 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[50] Idaho Power/203, Barretto/463 (Term Sheet).
[51] Idaho Power/501, Ellsworth/4 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[52] Idaho Power/501, Ellsworth/4 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[53] Idaho Power/501, Ellsworth/5 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).
[54] Idaho Power/501, Ellsworth/5 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

installation of a Kinport - Midpoint 345-kV series capacitor bank.[55] The two construction agreements, identified as Agreements 9 and 10 on Idaho Power/501, are expected to be executed in March 2023.[56]

Q. Are any changes to transmission service agreements between the Company and PacifiCorp necessary to facilitate the proposed ownership structure of the B2H project?

A. No. While initially contemplated in the Term Sheet,[57] PacifiCorp has determined it will not terminate its existing 510 MW of east-to-west transmission service across southern Idaho as initially anticipated. Rather, as shown on Idaho Power/501 as Agreement 11, PacifiCorp is expected to continue this existing 510 MW of PTP transmission service from Idaho Power.[58] PacifiCorp's PTP transmission service is term-specific, and has roll over rights, so PacifiCorp will continue to reserve its rights to either terminate the service or roll it over. PacifiCorp will make this decision every five years. Idaho Power will continue to plan its system assuming PacifiCorp retains its transmission service.

Q. Are there any additional agreements between the Parties necessary to facilitate the proposed ownership structure of the B2H project you have not discussed?

A. No. Idaho Power does not anticipate any additional agreements will be necessary to facilitate the proposed ownership structure of B2H.

II. B2H PARTNER BENEFITS

Q. Commission Staff indicates regional and system wide benefits associated with B2H for those areas served by Idaho Power, PacifiCorp and BPA.[59] What benefits does the ownership structure of B2H bring to BPA?

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[55] Idaho Power/501, Ellsworth/5 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

[56] Idaho Power/501, Ellsworth/5 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

[57] Idaho Power/203, Barretto/462 (Term Sheet).

[58] Idaho Power/501, Ellsworth/6 (Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for B2H).

[59] Staff's Opening Testimony and Exhibits of Sudeshna Pal (Staff/100, Pal/37-39) (Jan. 17, 2023).

A. In their Letter to the Region, included as Idaho Power/502, issued on January 9, 2023, BPA detailed their thoughts and decision-making process associated with the B2H project. In addition, on January 23, 2023, BPA hosted a workshop to discuss further with customers and stakeholders the "B2H with transfer service" proposal to execute contracts.[60] The presentation materials are included as Idaho Power/503. Both BPA's Letter to the Region and the workshop presentation materials have described BPA's business case, comparing costs under maintaining the existing plan of service with those under the proposed B2H with transfer service, estimating gross savings of $720 million over a 30-year period.[61] These cost savings will be passed on to BPA's customers, who are presented graphically in Idaho Power/504 Ellsworth/1, which identifies all BPA-owned transmission lines and substations, and Idaho Power/504 Ellsworth/2, which identifies the area BPA serves.

Q. Has BPA received any feedback from their customers and stakeholders regarding their proposed B2H with transfer service?

A. Yes. BPA received nine sets of public comments from customers and stakeholders regarding the proposed B2H with transfer service, eight of which were supportive. Included as Idaho Power/505 are the public comments in support of their B2H with transfer service proposal.

Q. What benefits does B2H bring to PacifiCorp?

A. As described in Idaho Power/100, Ellsworth/5, B2H will provide strategic value to PacifiCorp, who serves numerous jurisdictions in Oregon. In addition to connecting PacifiCorp's two balancing areas and providing bidirectional capacity to increase reliability and enable more efficient use of resources, the Project provides to PacifiCorp increased

[60] Idaho Power/503, Ellsworth/10 (BPA B2H Workshop).

[61] Idaho Power/502, Ellsworth/13 (Updated BPA Letter to the Region re: B2H and Southeast Idaho Load Service); Idaho Power/503, Ellsworth/10 (BPA B2H Workshop Presentation).

capability to serve customer growth in Central Oregon.[62] Similar to Idaho Power and BPA, PacifiCorp anticipates significant benefits associated with B2H—approximately $1.713 billion through 2042 as evidenced in PacifiCorp's First Supplemental Response to Staff's Data Request 13, filed on February 13, 2023. The cost/benefit analysis, provided as Confidential Attachment 13-1 to PacifiCorp's supplemental response, presents the risk-adjusted net benefits associated with B2H and the estimated decrease to customer costs.

Q. What is the sum of the partner benefits associated with the B2H project?

A. Using the most recent quantification of Idaho Power-specific customer benefits, which I will discuss later in my testimony, total benefits for the project partners are expected to be $2.66 billion:

Table 1. B2H Total Partner Benefits

B2H Project Partner	Total Benefits
Idaho Power	$228 million
BPA	$720 million
PacifiCorp	$1,713 million
Total	**$2,661 million**

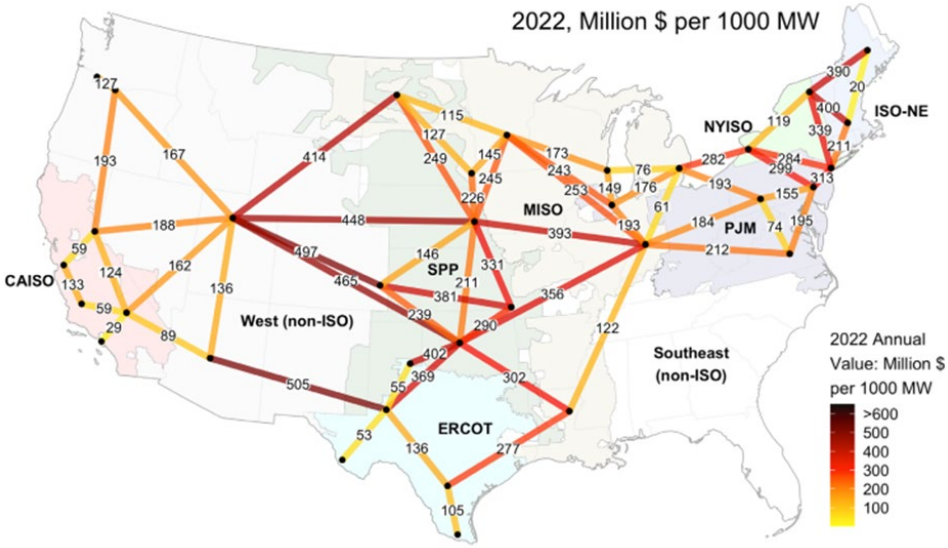
It is worth noting that the Company and PacifiCorp have presented benefits over a 20-year period while BPA's benefits are computed over a 30-year period. Should Idaho Power and PacifiCorp extend their analysis an additional 10 years, it is likely the customer benefits would be even greater. Idaho Power/504 Ellsworth/2 presents a graphical depiction of the location of the Company, BPA, and PacifiCorp's customers served in Oregon, highlighting how Oregonians will benefit from B2H and the vast area these customer benefits will cover.

Q. Are there any additional regional benefits you would like to discuss?

[62] PacifiCorp's Opening Testimony of Rick Link (PacifiCorp/100, Link/4) (Jan. 17, 2023).

A. Yes. In my Direct Testimony, I referenced a Lawrence Berkley National Laboratory ("Lawrence") study titled "Empirical Estimates of Transmission Value using Locational Marginal Prices" that quantified approximately $125 million per year in potential energy arbitrage-related value between the EIM_BPA Hub node and the EIM_UT node (the EIM Utah node is a close surrogate for Idaho Power).[63] On February 7, 2023, Lawrence provided an update that included 2022 data, highlighting the increased value in energy price differentials as $167 million, further emphasizing the benefits associated with transmission in the region.[64] The following map depicts the 2022 value of a hypothetical 1,000 MW line connecting the two locations across the United States as quantified by Lawrence, identifying the $167 million energy price differential.

Figure 1. Map Depicting Energy Price Differential Between EIM_BPA Hub Node and the EIM_UT Node



In addition, the Company has observed high amounts of power flow into the Pacific Northwest region during winter peaking events. For example, operationally, during Winter

[63] Idaho Power Company's Testimony and Exhibits of Jared Ellsworth (Idaho Power/100 Ellsworth/36-37) (Sept. 30, 2022).

[64] The article is available here: Dev Millstein, et al., LAWRENCE BERKELEY NAT'L LABORATORY, *The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade* (Feb. 2023) (available at https://emp.lbl.gov/publications/latest-market-data-show-potential) (last visited Feb. 19, 2023).

Storm Elliott in December 2022, the Pacific Direct Current Intertie ("PDCI") flowed nearly 1,000 MW into the Pacific Northwest. The Idaho to Northwest path flowed over 2,000 MW into the Pacific Northwest from Idaho. Flows on both paths were near existing ratings, and indicate that if additional capacity had been available, it likely would have been utilized. Considering projected winter growth rates in the Pacific Northwest due to electrification and limitations to the addition of fossil fuel-based dispatchable resources in Oregon and Washington, demand to import power into the Pacific Northwest during the winter will continue to increase over time. B2H will help meet that demand, benefiting the region by providing energy to Oregon from Idaho, Wyoming (including incremental Wyoming wind), and power from diverse southern markets, in the event of energy shortages. BPA publishes historical power flows for many paths, including PDCI and Idaho to Northwest, and has made them available.[65]

III. DETAILED B2H COST ESTIMATE

Q. Please identify Commission Staff's statement that you will be addressing in this section.

A. In their Opening Testimony, Staff raises a question regarding the Company's analysis in the 2021 Integrated Resource Plan ("IRP") showing that the Preferred Portfolio,—which included B2H, was $270 million more cost-effective than the highest scoring portfolio that did not include B2H. On that point, Commission Staff states that they are "not convinced that the avoided generation benefits have been accurately captured in the $270 million amount, because it does not reflect the most updated cost of the B2H project. Although Staff agrees that access to Pacific Northwest markets could result in potential customer savings by avoiding expensive generation resource buildouts to serve load needs, Staff has concerns around the net present value of benefits of $270 million ($266 million to be

[65] See DC Intertie and Idaho-Pacific NW studies at BPA - OPI Interties and Flowgates.

exact) that is reflected in the 2021 IRP and that Idaho Power has presented as supporting evidence."[66] Given Commission Staff's comments, I will walk through the quantification of the $270 million using the most recent B2H cost estimate, presented in the Ms. Barretto's Reply Testimony, to best address Commission Staff's concern.

Q. The B2H cost estimates provided in this docket have increased compared to the 2021 IRP. Does this cost increase suggest that B2H should not be selected as a least cost/least risk resource?

A. No. Future resource portfolio costs associated with the B2H estimate, created over 2020 and 2021, have increased since the Company developed and published the 2021 IRP. However, costs for ***all*** major electrical power infrastructure have increased, which means that consideration of B2H's increased costs must be compared with the increase in cost related to alternative resources.

The Company's demand is growing, and incremental new resources are required to meet this growth. The purpose of the IRP is to develop different resource portfolios to compare, and to ultimately select the least-cost, least-risk plan for meeting customer demand. The key consideration is the *comparing* of the portfolios. While the costs associated with B2H have increased, the costs in the competing portfolios have also increased. However, rather than focusing on all resource cost increases, I will explore cost increases associated with only the major transmission infrastructure as a conservative starting point. In doing this, I will explain how we can better understand the impact to 2021 IRP portfolio costs assuming higher costs related to B2H.

Q. As a first step in a detailed explanation about the B2H cost estimate, please list all the components of B2H, projects supporting B2H, and projects and costs associated with the asset exchange with PacifiCorp, that were included in the 2021

[66] Staff/100, Pal/32 (Jan. 17, 2023).

IRP.

A. The 2021 IRP included costs associated with all components of the B2H transaction, including local interconnection into the Treasure Valley transmission system, and costs related to the asset exchange with PacifiCorp.[67] The following is a list of the various components:

- Boardman to Hemingway Project
  - B2H transmission and substation costs
  - B2H midline series capacitor
  - BPA permitting buyout payment
- Local interconnection projects (230-kV line from Hemingway to Bowmont to Hubbard substations, including supporting equipment)
- Midpoint 500/345-kV second transformer addition
- Midpoint-Kinport 345-kV series capacitor
- PacifiCorp asset exchange costs

Q. Please describe the projects and costs directly related to B2H.

A. The direct B2H transmission and substation components include costs for permitting, preconstruction, right-of-way options, the transmission line itself, substation costs, overheads, contingency (which was excluded in the 2021 IRP modeling), and Idaho Power's Allowance for Funds Used During Construction ("AFUDC") and property tax. For modeling in the 2021 IRP, Idaho Power's share of the total direct B2H costs was approximately $425 million.[68] The local interconnection costs include an additional 230-kV transmission line from Hemingway into the Company's Treasure Valley transmission

[67] *In re Idaho Power Company, 2021 IRP*, Docket LC 78, IRP Appendix D at 6-9, 28-29 (Feb. 2022) (available at https://edocs.puc.state.or.us/efdocs/HAQ/lc78haq15183.pdf) (last visited Feb. 20, 2023)[hereinafter "2021 IRP, Appendix D"].

[68] 2021 IRP, Appendix D at 59.

network.[69] This line extends from Hemingway substation to Bowmont substation to Hubbard substation, includes substation related costs, and has a cost, excluding contingency, of about $35 million for 2021 IRP modeling.[70]

The B2H midline series capacitor is a substation located near the middle of the line that the Company is currently in the process of siting. The Company estimated its share of this project at about $10 million when modeling for the 2021 IRP.[71] Lastly, BPA has funded permitting of the B2H project for over a decade. In the 2021 IRP, the Company estimated that BPA's permitting interest was about $25 million. The Company assumed it would repay this permitting interest, with accumulated interest, 15 years after the B2H project is placed into service. The net present value ("NPV") of this permitting interest, as of the 2021 IRP, was approximately $14 million, and was utilized for total B2H cost purposes in the financial model. The resulting sum of all the components listed above is approximately $485 million ($425 B2H + $35 interconnection + $10 Midline + $14 permitting payback) and was the B2H cost estimate utilized for the purposes of the 2021 IRP.[72]

Q. How did the Midpoint 500/345-kV second transformer addition and the Midpoint-Kinport 345-kV series capacitor play a role in the B2H cost estimate utilized for 2021 IRP modeling?

A. First, I want to clarify that the Midpoint substation is located north of Twin Falls, Idaho,[73] and is separate and distinct from the B2H *midline* series capacitor, which the Company expects to be sited somewhere between La Grande and Durkee, Oregon.[74] The names are similar and can cause confusion.

[69] 2021 IRP, Appendix D at 28-29.
[70] 2021 IRP, Appendix D at 28.
[71] 2021 IRP, Appendix D at 59.
[72] 2021 IRP, Appendix D at 145.
[73] *See* 2021 IRP, Appendix D at 8.
[74] 2021 IRP, Appendix D at 9.

Idaho Power anticipates investing in the Midpoint 500/345-kV second transformer addition ("Midpoint Transformer") and the Midpoint-Kinport 345-kV Series Capacitor ("Kinport Series Capacitor") independent of the B2H project, however, the Company treated the cost and capacity of these two projects differently in portfolios inclusive of B2H, compared to portfolios exclusive of B2H. In B2H-inclusive portfolios, Idaho Power plans to include these assets as part of a larger asset exchange arrangement with PacifiCorp.[75] In portfolios exclusive of B2H, the Company would not transact on an asset exchange with PacifiCorp, and therefore assumed that Idaho Power and PacifiCorp would both participate in the upgrades, per the parties' JOOA, at their respective ownership shares. For B2H-inclusive portfolios, the Company conservatively assumed that it would be funding 100 percent of the cost of the Midpoint Transformer and Kinport Series Capacitor projects. Idaho Power estimated these two projects would cost about $47 million.[76]

Q. You mentioned a Midpoint Transformer Construction Agreement and a Kinport Capacitor Bank Construction Agreement earlier. How do these Agreements relate to the Midpoint Transformer and Kinport Series Capacitor just mentioned?

A. They are the same projects.

Q. How did the Company account for the asset exchange with PacifiCorp in the 2021 IRP?

A. As the Company developed its 2021 IRP, it did not have sufficient information regarding the PacifiCorp asset exchange to model a detailed cost associated with the transaction. Idaho Power determined, however, that there was sufficient information to make a conservative estimate. As I mentioned, the Company conservatively assumed that it would be funding 100 percent of the cost of the Midpoint Transformer and Kinport Series

[75] 2021 IRP, Appendix D at 8.
[76] 2021 IRP, Appendix D at 9.

Capacitor projects.[77] Idaho Power expects the cost of the two projects, plus the net book value ("NBV") of its existing transmission assets that will be transferred to PacifiCorp will exceed the NBV of the assets it is acquiring from PacifiCorp in the exchange, and therefore the Company modeled an estimate of these costs in the 2021 IRP.[78] For additional clarity, Idaho Power does not anticipate funding 100 percent of the cost of the Midpoint Transformer and Kinport Series Capacitor projects. Rather, this approach was intended as a conservative IRP estimate.

Q. How are the transmission costs incorporated into the total cost of each of the 2021 IRP resource portfolios that were evaluated?

A. The cost for every resource and transmission line in the Company's IRP is put into the Company's financial model to determine a levelized cost—i.e. an annual revenue requirement associated with the Project. By developing a levelized cost for all resources and transmission lines, the Company can achieve an apples-to-apples cost comparison between alternatives within the 20-year planning window. As described in Idaho Power/100 Ellsworth 25, as part of the 2021 IRP, the Company developed a branching scenario analysis strategy to ensure that the resulting portfolios reasonably identified an optimal solution. This included various combinations of the B2H project, the Gateway West project, and a "do nothing" scenario, which allowed no major 500-kV transmission projects.[79] The appropriate transmission costs, therefore, can be simply added onto the portfolio associated with a specific transmission topology assumption, also referred to as bolt-on costs.

Q. How does the Company determine the portfolio NPV impact of each transmission component previously discussed?

[77] 2021 IRP, Appendix D at 9.

[78] *See* 2021 IRP, Appendix D at 9 (explaining the Company's conservative assumption and inclusion of costs for these projects).

[79] Idaho Power/102, Ellsworth/1 (Branching Evaluation).

A. Once Idaho Power has a levelized cost of each project, the Company must determine an in-service date year for each of the transmission components. Idaho Power will then assign the levelized cost starting in the in-service date year, and every year thereafter, until the end of the planning window (in the case of the 2021 IRP, the planning window ends in 2040). The Company will then calculate the NPV of this cost stream, which will then be incorporated into the total portfolio NPV cost. An example, if a project has a levelized cost of $10 million/year, and an in-service date of 2028, the Company will calculate the NPV in 2021 dollars of a $10 million/year annual cost stream starting in 2028 and ending in 2040.

Q. What are the levelized costs and portfolio NPV costs of each of the major transmission components analyzed in the 2021 IRP?

A. The total Idaho Power cost, and levelized cost, are listed in the table below:

Table 2. Levelized and Portfolio NPV Costs of Transmission Components in 2021 IRP

Project Description	Total Cost	Levelized Cost	In-Service Year	Portfolio NPV Cost
B2H (with local interconnection)	$485M	$23.2M	2026 (Preferred Portfolio)	$159.5M
Midpoint Transformer & Kinport Series Capacitor	$47M	$3.8M	2026 (Preferred Portfolio)	$25.8M
GWW (with local interconnection)	$211M	$16.4M	2027 (Non-B2H Portfolio)	$100.9M
GWW (w/o local interconnection)	$176M	$13.2M	2033 (Non-B2H Portfolio)	$36.8M
Midpoint Transformer & Kinport Series Capacitor (No PacifiCorp exchange)	$16.2M	$1.3M	2027 (Non-B2H Portfolio)	$8.2M

The table includes costs associated with the Gateway West project, as assumed in the 2021 IRP.[80] I will use these costs for comparative purposes later in my testimony.

Q. Idaho Power has increased the B2H cost estimate compared to B2H costs included in the 2021 IRP. Please detail how the cost estimates have changed.

[80] Idaho Power's Petition for CPCN, Attachment 14 (Idaho Power's 2021 Integrated Resource Plan) at 119 [hereinafter "2021 IRP"].

A. Yes, as discussed in Idaho Power/300 Barretto/1, the Company revised and updated its B2H cost estimate at both the 30 percent detailed design stage and 60 percent detailed design stage in 2022. In addition, in Ms. Barretto's Reply Testimony, the Company provides a revised cost estimate that incorporates the correction of two errors which in total decreased Idaho Power's share of B2H costs by $1.2 million.[81] I will use the B2H project costs identified in Confidential Idaho Power/401 and break down the cost estimates comparatively to the cost estimate from the 2021 IRP.

The direct B2H transmission and substation components for the Company have increased from $425 million,[82] not including a contingency, in the 2021 IRP to $603 million, including a contingency. The $603 million is an all-inclusive cost estimate, which includes costs for permitting, preconstruction, right-of-way options, the transmission line itself, substation costs (now including the midline series capacitor station), overheads, contingency, and Idaho Power's AFUDC and property tax.

Q. How do the Total B2H Project Estimated Costs between the 2021 IRP and Idaho Power/401 compare?

A. The total cost of the project is approximately $1,149 million, plus $110 million for Idaho Power AFUDC and property tax, plus an estimated $132 million associated with PacifiCorp's AFUDC and property tax. This results in a total B2H component cost estimate of $1,391 million. Please note, the Company has a firm understanding of the direct cost of the project, and Idaho Power's AFUDC and property tax costs, but has estimated PacifiCorp's AFUDC and property tax costs, because Commission Staff and intervenors have requested a total project cost estimate.

The local interconnection costs have increased from $35 million (excluding

[81] Idaho Power/400, Barretto/2.
[82] 2021 IRP, Appendix D at 59.

contingency)[83] in the 2021 IRP to about $47 million (including contingency). The B2H midline series capacitor was a separate $10 million line-item in the 2021 IRP, but these costs are now incorporated into the direct B2H transmission and substation costs identified earlier. The payback of BPA permitting remains a separate line item. Idaho Power estimates this amount has increased from $25 million in the 2021 IRP to about $28 million based on the Purchase, Sale, and Security Agreement I discussed earlier in my testimony. Under the Purchase, Sale, and Security Agreement, the Company must determine an NPV associated with this repayment. The NPV value of the permitting interest repayment increased from $14 million in the 2021 IRP to about $17 million. The sum of all the components is approximately $668 million ($603 B2H + $47 interconnection + $17 permitting payback) as compared to approximately $485 million the 2021 IRP.

Finally, the Company continues to expect the Midpoint Transformer and Kinport Series Capacitor will cost $47 million and will continue to assume the Company is funding 100 percent of these costs as a conservative estimate. Therefore, this component remains unchanged.

Q. What are the updated levelized costs and portfolio NPV costs of each of the major transmission components after the B2H cost updates?

A. The updated total Idaho Power cost, and levelized cost, are listed in the table below. For comparison purposes, the 2021 IRP Portfolio NPV Cost column was added as well.

Table 3. Updated Levelized and Portfolio NPV Costs of Major Transmission Components

Project Description	Total Cost	Levelized Cost	In-Service Year	Updated Portfolio NPV Cost	2021 IRP Portfolio NPV Cost
B2H (with local interconnection)	$668M	$35.6M	2026 (Preferred Portfolio)	$244.2M	$159.9M
Midpoint Transformer & Kinport Series	$47M	$3.8M	2026 (Preferred Portfolio)	$25.8M	$25.8M

[83] 2021 IRP, Appendix D at 28.

Capacitor					
GWW (with local interconnection)	$284.9M	$22.0M	2027 (Non-B2H Portfolio)	$135.4M	$100.9M
GWW (w/o local interconnection)	$238M	$17.7M	2033 (Non-B2H Portfolio)	$49.4M	$36.8M
Midpoint Transformer & Kinport Series Capacitor (No PacifiCorp exchange)	$16.2M	$1.3M	2027 (Non-B2H Portfolio)	$8.2M	$8.2M

Q. Please describe the effect of the increased cost estimate on the Preferred Portfolio in the 2021 IRP.

A. As I described earlier, transmission costs are a bolt-on portfolio cost, therefore factoring in the cost increases is as straightforward as removing the prior transmission cost estimates and layering in the new estimates. After doing this, the total cost of the Preferred Portfolio increases from $7,942 million in the 2021 IRP to $8,027 million with the latest estimate. This represents an $85 million NPV portfolio cost increase.

Q. Focusing on just B2H, how can the cost of B2H increase from $485 million to $668 million, a $183 million increase, and the Preferred Portfolio cost increase by only $85 million?

A. The difference between $485 million and $668 million is a direct capital cost increase, however, portfolio costs are NPV costs. Therefore, these costs are not directly comparable. The new B2H total cost must be levelized into an annual cost and once levelized, the Company can calculate an NPV associated with project being placed in-service in 2026. The levelized cost will be applied each year annually as a portfolio cost in years 2026 through the end of the planning window in 2040 to determine the portfolio NPV associated with the project.

Q. What is the cost estimate of the least-cost IRP portfolio that does not include B2H?

A. In the 2021 IRP, the least-cost non-B2H portfolio is the "Base without B2H PAC Bridger

Alignment" portfolio.[84] In the 2021 IRP, the total cost of that portfolio was $8,208 million.[85] The least-cost non-B2H portfolio included the need for Gateway West, another 500-kV transmission project, that the Company is jointly developing with PacifiCorp.[86] Idaho Power developed the Gateway West cost estimate that was utilized in the 2021 IRP as a derivative of the Company's B2H cost estimate. As an approximation, the Company assumed the Gateway West cost per mile would be equivalent to the B2H cost per mile. Therefore, since portfolios are meant to be compared, it would be appropriate to update the Gateway West estimate consistent with the update to the B2H estimate. The Company made those updates in the table I presented with updated B2H project costs. The Company completed this exercise, and the result was that the Base without B2H PAC Bridger Alignment portfolio cost increases from $8,208 million in the 2021 IRP to $8,255 million using the latest B2H estimate.

Ultimately, the result of increased B2H transmission costs is that the difference between the least-cost B2H portfolio and the least-cost non-B2H portfolio is $8,027 million compared to $8,255 million—representing a $228 million difference. For reference, the 2021 IRP was $7,942 million compared to $8,208 million—a $266 million difference.[87] The conclusion: when considering only updated transmission costs, the gap between the least-cost B2H portfolio and the least-cost non-B2H portfolio reduced from $266 million in the 2021 IRP, to $228 million with the most recent estimate. The least-cost B2H portfolio remains, hands-down, the optimal portfolio.

Q. You have focused on revised transmission cost estimates. Have costs changed for other resources in the 2021 IRP?

A. I focused my discussion on transmission costs because transmission costs are all bolt-on

[84] 2021 IRP, Appendix D at 145.
[85] 2021 IRP, Appendix D at 145.
[86] 2021 IRP, Appendix D at 56.
[87] 2021 IRP, Appendix D at 8.

costs, and therefore any cost estimate changes would not have resulted in changes to the resource portfolio selected by the AURORA long-term-capacity-expansion model. Additionally, solely focusing on the increase in transmission costs provides the most conservative estimate for evaluating B2H, as the cost of other resources has increased in-line with the increased costs the Company is seeing associated with transmission. For example, as Idaho Power has begun development of its 2023 IRP, the base cost for 4-hour duration lithium-ion storage has increased from $1,150 per kW (2021 basis) in the 2021 IRP,[88] to $1,600 per kW (2024 basis) in the 2023 IRP. The least-cost non-B2H portfolio included 2,165 MW of battery storage,[89] and the Preferred Portfolio (with B2H) included only 1,685 MW of battery storage.[90] This 480 MW difference in battery energy storage, when considering the $450 per-kW increase in the cost of battery storage, shows that the gap between the Preferred Portfolio and the least-cost non-B2H portfolio, in fact, may not have narrowed at all, and rather expanded beyond the original $266 million.

Q. Should Commission Staff be concerned of the possibility that updated B2H costs could have resulted in B2H not being part of the Company's 2021 IRP Preferred Portfolio?

A. No. As evidenced by the analysis performed using updated B2H project costs, it is evident the least-cost B2H portfolio remains the optimal portfolio, and holistic updated costs may have actually resulted in further widening the gap between the Preferred Portfolio with B2H and the best performing non-B2H portfolio.

IV. RELIABILITY AND THE B2H PROJECT

Q. Is the B2H project necessary for the reliability of Idaho Power's transmission supply?

[88] 2021 IRP, Appendix C at 43 (available at https://edocs.puc.state.or.us/efdocs/HAA/lc78haa103337.pdf) (last visited Feb. 20, 2023).
[89] 2021 IRP, Appendix C at 71.
[90] 2021 Integrated Resource Plan at 152.

A. Yes.

Q. **On what basis does Commission Staff conclude that the B2H is not necessary for reliability purposes?**

A. Staff bases its statement on Idaho Power's Response to Staff's Data Request No. 25 ("Response to Data Request No. 25") asking the Company to "provide an account of foregone resources, outages, and any other reliability and resilient impacts that could have been avoided if B2H was in place."[91] In its response, the Company explained that it has not modeled the hypothetical scenario, but acknowledged that in the past, the Company's reliability and resilience were unlikely to have changed.[92] It appears that Staff relied on that statement to reach the conclusion that Idaho Power does not contend that B2H is required to provide reliable service. This conclusion, however, is not an appropriate one. Reliability, looking into the past, can be measured with various metrics, but reliability looking forward is a function of exposure and risk. For example, if a single transmission line serves a community, it may have perfect reliability looking backward if the line never experiences an outage. However, one cannot use the past to definitively conclude a second line may not be required for reliability purposes. The Company acknowledges the Project's reliability considerations are not as simple as this single line serving a community example, but provides the context to challenge Commission Staff's conclusion.

Q. Were there any additional items associated with Commission Staff's assessment of the Project's reliability benefits Idaho Power would like to address?

A. Yes. Staff challenges the Company for stating that B2H enhances reliability, and that "enhancement of reliability, however desirable, is different from maintenance of reliability, which is what Staff reads as a requirement under OAR 860-025-0035(1)(a)."[93] OAR 860-

[91] Staff's Opening Testimony and Exhibits of Yassir Rashid (Staff/200, Rashid/10) (Jan. 17, 2023).

[92] Staff/200, Rashid/10 (Jan. 17, 2023).

[93] Staff/200, Rashid/11 (Jan. 17, 2023).

025-0035(1)(a) requires the Petition indicate *whether the transmission line will meet a demonstrated need for transmission of additional capacity or improved system reliability that enables the petitioner to provide or continue to provide adequate and reliable electricity service*. Idaho Power's interpretation of the intent of OAR 860-025-0035(1)(a) with respect to reliability is that the Company should evaluate the system with and without B2H and then consider reliability in terms of exposure and risk. Or, using my previous example, considering future risk and exposure for reliability purposes, does the community require two redundant lines, or is one line sufficient. In the case of B2H, considering future risk and exposure, as well as cost, does Idaho Power require B2H, or can Idaho Power manage reliability without B2H?

Q. Understanding the Company's interpretation of OAR 860-025-0035(1)(a) and considering future risk and exposure, as well as cost, does Idaho Power require B2H or can Idaho Power manage reliability without B2H?

A. Idaho Power requires B2H for reliability purposes. First, through the IRP process, a resource portfolio that balances cost, risk, and environmental concerns is selected. For reliability purposes, in the 2021 IRP the Company planned its resource portfolio to meet Loss of Load expectation ("LOLE") of 0.05 days per year or better, or less than one resource adequacy related outage event in 20 years.[94] As I discussed previously, the economic gap between the 2021 IRP Preferred Portfolio, which utilizes B2H to help achieve the required LOLE, and the least-cost non-B2H portfolio is $228 million, indicating B2H is the most cost-effective resource addition for serving load and maintaining system reliability.

If Idaho Power were to remove B2H from the 2021 IRP Preferred Portfolio, an adequate LOLE would not be achieved, and other resources would be required to maintain

[94] 2021 IRP at 116-17.

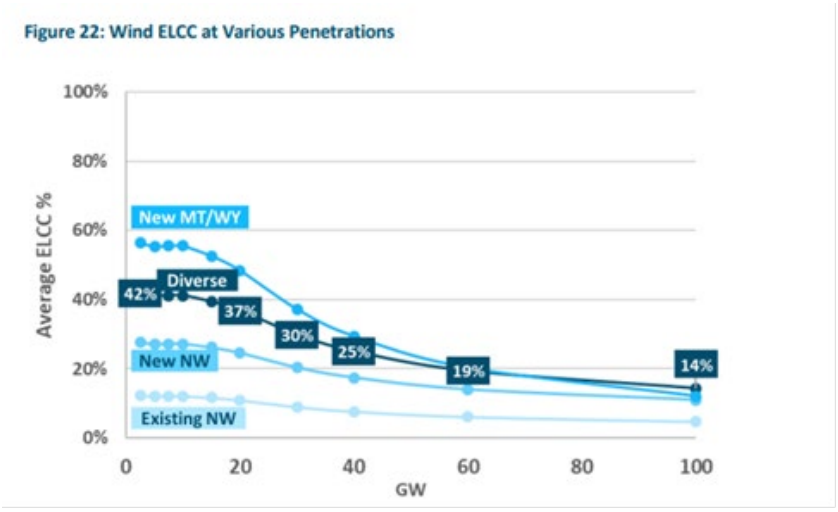
adequate reliability. While this fact alone indicates that B2H is necessary for reliability purposes, also consider the reliability of the 2021 IRP Preferred Portfolio as compared to reliability of the least-cost non-B2H portfolio. The 2021 IRP Preferred Portfolio required 41 MW of additional fixed-capacity generation, spread over the last four years of the planning window (7 MW, 3 MW, 15 MW, and 16 MW starting in 2037), to meet reliability targets. It is likely the Company could have achieved that 41 MW with a combination of solar, wind, and storage, although those resources were beginning to become less effective toward the end of the IRP planning window. The least-cost non-B2H portfolio required 305 MW of additional fixed-capacity generation, starting with 200 MW in 2035. A reasonable combination of wind, solar, and storage could not meet the 305 MW reliability gap.

Q. What prevents a combination of wind, solar, and storage from meeting a reliability gap, in 2035, as large as 305 MW?

A. The Company is finding, when performing informational Loss of Load studies for internal analyses, that at a certain point, continued addition of wind, solar, and storage inside the Idaho Power footprint has significant diminishing returns on capacity contribution. These diminishing returns are due to homogeneous weather patterns spread across the Idaho Power footprint causing simultaneous system-wide low wind, or low solar, or a combination of the two. The findings are also supported by the Resource Adequacy in the Pacific Northwest report published by Energy+Environmental Economics.[95] The figures below present the report findings with respect to decaying Effective Load Carrying Capability as penetration increases for wind, solar and storage.

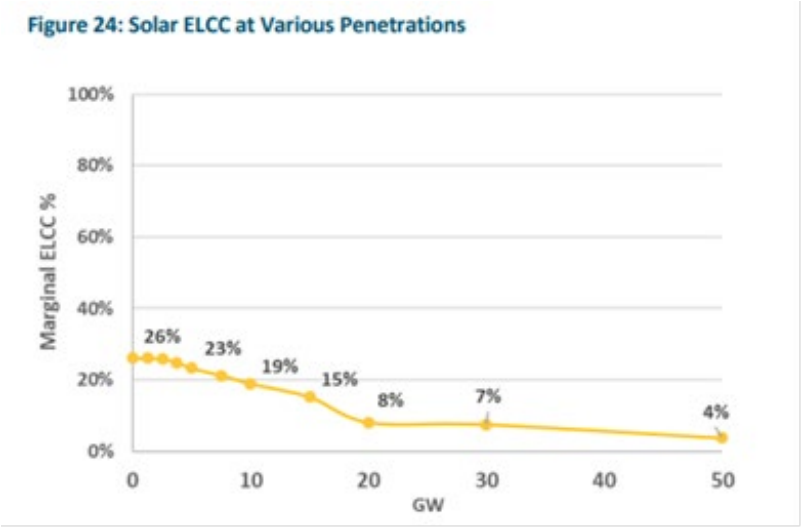
[95] Idaho Power/506 (ENERGY and Envt'l Econs., *Resource Adequacy in the Pacific Northwest* at 56 (Mar. 2019)).

Figure 2. Wind ELCC at Various Penetrations



[96]

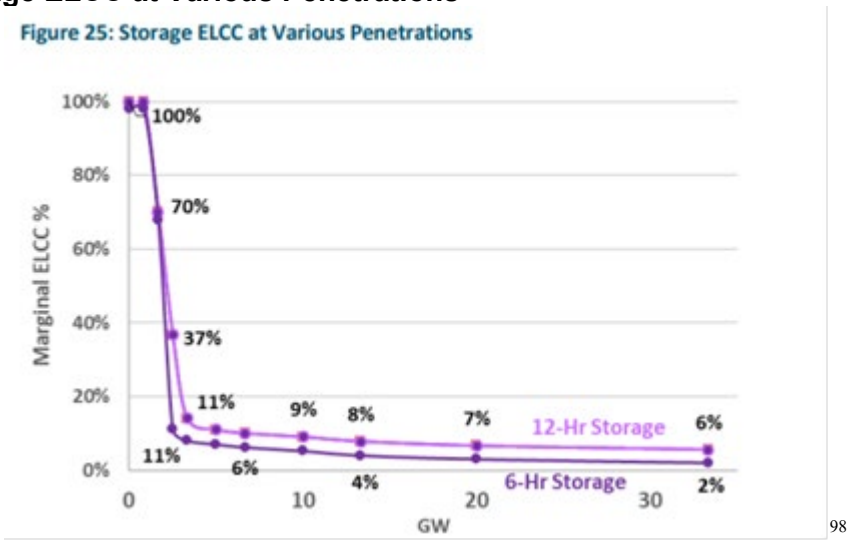
Figure 3. Solar ELCC at Various Penetrations



[97]

[96] Idaho Power/506, Ellsworth/67 (*Resource Adequacy in the Pacific Northwest*).
[97] Idaho Power/506, Ellsworth/69 (*Resource Adequacy in the Pacific Northwest*).

Figure 4. Storage ELCC at Various Penetrations



[98]

The least-cost non-B2H portfolio, therefore, would require additional natural gas, or a yet-to-be-identified future capacity resource. As evidenced in the 2021 IRP Preferred Portfolio, transmission between regions is the solution, and necessary to meet reliability targets in a clean-energy future.

Q. Can you provide any additional support for Idaho Power's need for B2H for reliability purposes?

A. Yes. As a transmission provider, Idaho Power has an obligation to BPA to provide reliable transmission service between the BPA footprint and BPA customers within the Idaho Power transmission footprint. Currently, Idaho Power's transmission connections with BPA's system are fully utilized, and BPA's existing Eastern Oregon and Southern Idaho load continues to grow, as does BPA's Southeast Idaho load. As obligated under the Company's OATT, new transmission is required and the Project is, and continually has been, the identified solution for many years as evidenced in the Northern Tier Transmission Group and NorthernGrid biennial regional transmission plans consecutively

[98] Idaho Power/506, Ellsworth/70 (*Resource Adequacy in the Pacific Northwest*).

beginning 2007.[99] Absent B2H, the alternative is a different transmission line between the Pacific Northwest and Idaho. A transmission line is required for reliability purposes and B2H is that transmission line.

Further, B2H preserves BPA's ability to maintain similar reliability associated with its Northwest AC Intertie as load continues to grow in Central Oregon—a key element of PacifiCorp's B2H justification.[100] Absent B2H, either reliability to that region may diminish, customer growth may be limited, which could cause economic harm to Oregon, or a much more expensive solution would have to be put in place. Finally, OAR 860-025-0035(1)(a) needs to be applied reasonably. Taking this standard to an extreme—suggesting a project is not required to meet reliability requirements if there is an alternative that could also meet reliability requirements—is nonsensical. This logic would suggest that nothing could meet the standard because there is always an alternative. The alternative to B2H costs more, is less reliable, will take more time, and results in a comparatively inferior power system, and that only presents the impacts for Idaho Power. BPA and PacifiCorp's reasons for building B2H suggest that they would align with those issues, and perhaps have more of their own.

Q. Commission Staff suggests in their Opening Testimony that there are alternatives to B2H that will provide the Company with similar benefits.[101] Do you agree?

A. No. The Project provides a unique and robust set of values to the Company that cannot be met with a typical resource, traditional or new. Without providing any specificity or supporting data, Staff states that "there are other resources which could provide similar benefits without the B2H project. These include Public Utility Regulatory Policies Act projects, power purchase agreements ("PPA"), generation resources including hydro,

[99] *See generally* Idaho Power/203, Barretto/480-899 (Northern Tier Transmission Group and NorthernGrid Regional Transmission Plans 2007-2021).

[100] PacifiCorp/100, Link/4 (Jan. 17, 2023).

[101] Staff/100, Pal/38-39 (Jan. 17, 2023).

coal, gas, demand side resources like energy efficiency and demand response, and market purchases using existing transmission lines."[102] The Company does not believe these resources can provide anywhere near the same benefits provided by B2H for numerous reasons. Consider the following:

- The 2021 IRP Preferred Portfolio, including B2H, is $228 million more cost effective than the least-cost non-B2H portfolio. The same alternative resources mentioned by Commission Staff were evaluated in the IRP, therefore, those alternatives are unable to provide the $228 million in avoided costs.
- The Project singularly meets the needs of Idaho Power's transmission customer BPA.
- B2H provides a regional connection to shared load and resource diversity—only a transmission line can facilitate that opportunity.
- The Project enables an asset exchange allowing Idaho Power to acquire transmission capacity to the Four Corners market hub, which will be critical in the winter in future years; other resources identified by Commission Staff do not expand Idaho Power's market access.
- There is not existing transmission capacity available from Idaho Power to market hubs to bring market purchases to customer load during time of high demand.
- B2H will help facilitate the connectivity of future markets, such as the California Independent System Operator's extended day ahead market and the Southwest Power Pool's markets.

To address Staff's list specifically, new hydroelectric resources are not available in

[102] Staff/100, Pal/38-39 (Jan. 17, 2023).

the United States, and coal is not feasible as it is not cost-effective, contrary to clean energy goals, and likely impossible to permit. Incremental natural gas, which comes with some amount of unquantifiable risk, Public Utility Regulations Policies Act projects, and PPAs (equivalent to renewables), energy efficiency and demand response were all potential resources additions evaluated in the 2021 IRP and none of them were selected to replace B2H as least-cost, least-risk resource additions.[103] Finally, as explained in the 2021 IRP, market purchases using existing transmission are not possible, due to an already constrained transmission system.[104]

For these reasons, Staff's assertion that Idaho Power could acquire "similar benefits without the B2H project"[105] is false. The resources may help the Company meet load requirements in the near-term, but would not offer similar benefits to B2H. In the long term, again, transmission is needed to reliably serve customers during extreme weather conditions.

V. RESOURCE ADEQUACY AND THE MID-C MARKET

Q. The Stop B2H Coalition ("STOP B2H") raises concerns about energy prices at Mid-C, resource adequacy at Mid-C, and the result of breaching the Snake River dams.[106] Do you agree with their conclusions?

A. No. Many of STOP B2H's conclusion are inaccurate and fail to consider the larger story. First, STOP B2H indicates Mid-C prices will increase due to increased demand associated with B2H exporting power from Mid-C.[107] It is important to note that the AURORA modeling captures forecasted Mid-C pricing so any increases in Mid-C prices are a component of the 2021 IRP Preferred Portfolio costs. On this point, it is likely that prices

[103] 2021 IRP at 191-212.
[104] 2021 IRP at 208-209.
[105] Staff/100, Pal/38 (Jan. 17, 2023).
[106] STOP B2H's Opening Testimony and Exhibits of Jim Kreider (STOP B2H/100, Kreider/4) (Jan. 17, 2023).
[107] STOP B2H/100, Kreider/4 (Jan. 17, 2023).

will increase at times due to increased demand for supply in the region. However, it is also likely that the addition of B2H will result in decreased prices at Mid-C during times when supply is constrained, because the Pacific Northwest region will be able to import more power from Idaho and regions to the south. Increased competition for resources benefits the interconnected transmission system.

Resource adequacy is a major focus across all regions in the United States. The Pacific Northwest region's primary resource adequacy issues remain in the winter, as a cursory read of the Pacific Northwest Power Supply Adequacy Assessment for 2027, referenced in STOP B2H's testimony, would suggest.[108] Idaho Power's primary need remains in the late-June, early-July timeframe because of irrigation load. The Company and other experts expect the Pacific Northwest region to continue to build to meet its winter growth requirements, especially given electrification and retirement and/or limited coal and natural gas capacity factor requirements. This will provide further opportunity for the Company to purchase power from the market when needed in the late-June, early-July timeframe. Of note, all regions go through times of surplus and scarcity, as evidenced by the California energy crisis. B2H is a 100-plus-year investment and will provide consistent value interconnecting regions throughout the year. The Project will also allow the Pacific Northwest utilities to move clean energy around where it's needed, when it's needed.

Finally, STOP B2H suggests the Company did not consider the impacts of potentially breaching the Snake River dams in its analysis "with their loss of generation capacity."[109] This statement is partially inaccurate and misleading. First, there is no definitive policy decision indicating Snake River dams will be breached, and second, the more robust proposals associated with breaching the dams all recognize the lost energy impacts. These lost energy impact quantifications include placeholder costs for

[108] Stop B2H's Amended Testimony and Exhibits of Jim Kreider (STOP B2H/100, Kreider/4) (Feb. 1, 2023).

[109] STOP B2H/100, Kreider/4 (Jan. 17, 2023).

replacement resources, at least on an energy basis, that would need to be installed in the region.

Q. Prices at Mid-C have been elevated recently. Were these Mid-C price increases modeled in the Company's 2021 IRP?

A. Historical and near-term market prices are currently being impacted by a myriad of factors, but the primary issue is elevated natural gas prices compared to what was expected when the Company was developing its 2021 IRP. This recent increase in prices was caused by market dynamics impacted by the Ukraine conflict, geopolitics, and even alleged sabotage of natural gas pipelines. The uncertainty around natural gas, as well as continued drought conditions, power and transmission scarcity concerns in the late-summer, and near-term market policy uncertainty is causing increased energy prices. These uncertainties are unlikely to be sustained for a prolonged period. In fact, recent forward prices show a notable decline in prices compared to some of the recent highs.

Q. What do you mean by market policy uncertainty?

A. Right now, there is uncertainty at the Mid-C hub because of uncertainty around policy associated with the Washington Clean Energy Transformation Act and the Washington cap-and-invest program. Numerous utilities, marketers, power traders, etc., make transactions at the Mid-C hub. Often an entity from outside Washington will sell at Mid-C, and the purchasing counterparty will also be located outside Washington. Although the parties to the transaction are outside of the state, the transaction takes place in Washington. There is a question as to whether the carbon content of the energy associated with those transactions needs to be tracked and whether Washington's policies apply to the hub, or only to utilities serving customers in the state of Washington, or some alternative. Due to the current uncertainty, anticipated until lawsuits are resolved, many selling entities do not want to make long-term sale commitments because they do not know how the policy will unfold.

Q. Do you anticipate these Mid-C issues will be settled prior to energization of B2H?

A. Yes. Mid-C is an important energy hub in the west, so I anticipate resolution for a market solution will be in place prior to B2H being placed in-service in 2026.

Q. Does the Company believe that there will be power to buy from the Mid-C market?

A. Yes. Idaho Power has provided various materials about the depth of the market in its 2021 IRP Appendix D.[110] Additionally, since the late summer of 2020, the Company has seen a major increase in marketers attempting to acquire transmission service from Idaho Power to allow them to sell into the southern markets, as well as into Idaho. Marketers must have power to sell if they are trying to get through Idaho Power to sell it, supporting the Company's belief that there will be power to buy from Mid-C. Also of note, demand for transmission service provides an economic hedge for Idaho Power's retail customers. The Project will be highly utilized between market purchases for Idaho Power retail customers, its primary use, and transmission service for other western entities.

VI. CLARIFICATIONS TO THE OPENING TESTIMONY OF COMMISSION STAFF AND INTERVENORS

Q. Are there any additional items from the Opening Testimony you would like to address?

A. Yes. In their Opening Testimonies, Commission Staff, STOP B2H, and Mr. Greg Larkin identify several items for which they had concerns, are unable to draw a conclusion with the information provided, include inaccurate conclusions, or contain misinformation that I would like to clarify. I will begin with the concern expressed by Commission Staff regarding non-monetized benefits of renewable integration.

A. Commission Staff

Q. Does Staff agree there are non-monetary benefits from the B2H project?

A. Yes.[111] However, Commission Staff lists "renewable integration" as one of the items of

[110] 2021 IRP, Appendix D at 31-34.
[111] Staff/100, Pal 36 (Jan. 17, 2023).

uncertainty. The Company believes that this concern may indicate that Staff is unintentionally conflating the terms "renewable integration" and "renewable interconnection" when considering this benefit.

Q. What benefits does the Company believe B2H will provide with respect to renewable integration?

A. Integration is the ability of the Company to follow the intermittent nature of renewable resources in real-time operations and is a vital component to meeting clean energy goals. Transmission lines, and connections with other grids, help with renewable integration by providing connections to geographically diverse loads and resources (e.g., the Energy Imbalance Market). Integration benefits will begin the moment B2H is placed in-service as it will provide an immediate connection to geographically diverse loads and resources in the Pacific Northwest. A future Variable Energy Resource Integration Study will inform the benefits provided by B2H.

Q. Will B2H help Oregon achieve its clean energy goal?

A. Yes. In its Response to Standard Data Request No. 13, Idaho Power provided a narrative explaining how B2H enhances Oregon's ability to reach greenhouse gas reduction, environmental, and climate change goals, including reference to various studies that detail the value and necessity of transmission to meet clean energy targets – and indeed more material about the benefits of transmission is published regularly. For example, a Net Zero America report by Princeton, included as Idaho Power/507, concluded that the United States will need to expand its electricity transmission system by 60 percent by 2030 in order to achieve net-zero emissions by 2050.[112] Because Commission Staff has indicated Idaho Power's explanation was not clear, rather than providing more references to general studies, I will focus specifically on B2H's benefits.

[112] Idaho Power/507, Ellsworth/14 (PRINCETON UNIV., *Net Zero America Potential Pathways, Infrastructure, and Impacts* (Dec. 15, 2020)).

B2H will initially provide 1,000 MW of additional Oregon import capacity, and with the addition of Gateway West, which will increase southern market access and provide access to Wyoming wind, the Oregon import capacity will increase to 2,000 MW. Today, the most economic carbon-free resources are hydro, wind, and solar. Oregon is fortunate to have significant carbon-free hydro generation; however, additional resources will be required to meet Oregon's clean energy goal. Wind and solar produced in the state will help, but Oregon is small enough geographically that a singular weather pattern can impact the entire state and reduce the energy output of wind and solar resources for extended periods. These risks are pronounced in winter when renewable resources' ability to meet peak demand is reduced.

Idaho Power recently experienced one such weather event from January 16, 2022, through January 27, 2022, when the area experienced a prolonged period of low renewable generation. During this time, the Company's solar and wind resources generated power at capacity factors of only about 7 percent and 6 percent, respectively. Idaho Power overcame these renewable shortfalls by dispatching its natural gas and coal facilities and through market purchases across its transmission system. Technologies like hydrogen are not mature enough and have high uncertainty (as is the case with nuclear), or are not currently cost-effective (as is the case with geothermal or biomass technologies). Considering a future power system dominated by clean energy resources, and the need to plan for and overcome extreme weather patterns, transmission connections to diverse regions are a necessity. With the addition of Gateway West, B2H will increase the Oregon import capability by 2,000 MW. This represents approximately 15 percent of Oregon's total load; therefore, this capacity represents a very large and robust connection to another location on the grid that may not be experiencing similar extreme weather pattens. Extreme weather patterns, in a grid dominated by variable resources, is a major issue that the grid of the future must overcome. This lack of

connection to diverse resources is something that has caused issues in other areas, such as Texas. B2H will provide an immediate connection to geographically diverse loads. This lack of connection to diverse resources is something that has caused issues in other areas, such as Texas.

Q. What clarification would you like to make regarding the major transmission equipment associated with the B2H project?

A. In their Opening Testimony, Commission Staff states when describing the various B2H components:

> The purpose of the shunt capacitors and reactors is to provide improvements in the power transfer capability of the line, improve system stability, reduce system losses, and improve voltage quality. The transmission line design also includes a series capacitor substation somewhere in the middle of the transmission line. The purpose of this substation is to maintain voltage at the adequate operating levels for the transmission line, and this substation and the shunt reactors and capacitors at Longhorn are particularly important as the resource mix shifts toward renewable resources, where reactive power is less available.[113]

Idaho Power would like to clarify that B2H will include shunt capacitors and shunt reactors at both the Hemingway and Longhorn substations and also to explain the purpose of the equipment. The primary reason for shunt devices is voltage control (including voltage quality and voltage stability), line switching, and reliability. Shunt capacitors increase system voltage, and shunt reactors reduce system voltage. High-voltage lines, such as B2H, require shunt reactors for operational purposes to: (1) reduce voltage when the line is lightly-loaded with power flow because in these situations the line looks to the system like a large capacitor, (2) reduce the voltage on the line upon energization after it has been out of service, and (3) in the case of B2H, a shunt reactor with an attached neutral reactor will allow the Company to implement single-pole-reclosing. Single-pole-reclosing occurs if a single-line-to-ground fault is detected on the line, only one of three-

[113] Staff/200, Rashid/6 (Jan. 17, 2023).

phases will open, the fault (if temporary in nature—such as lightning) will extinguish, the open phase will reclose, and the line will continue normal operation. Single-pole-reclosing reduces the transmission line down-time caused by unexpected disturbances and enhances system stability during disturbances, thereby reducing risk, and improving reliability.

The Project will include series capacitors at Hemingway substation, Longhorn substation, and a midline substation. These devices also increase system stability by reducing the reactive impedance of the line, making the line appear electrically shorter (meaning stronger, or more robust). By reducing the reactive impedance of the line, the series capacitors can increase power flow across the line when inserted or reduce power flow when bypassed. Shunt capacitors, shunt reactors, and series capacitors are a necessary component of the B2H transmission equipment. This transmission line itself, and not just its components, is critical to the grid as the resource mix shifts towards renewables.

B. STOP B2H

Q. STOP B2H suggests Idaho Power acquire a lot of renewables in Idaho rather than construct B2H.[114] Is that an option?

A. No. STOP B2H states that "[l]ogic would suggest that if Idaho Power built more of their own renewable generation in Idaho, closer to load and enhancing its intrastate transmission/distribution system. It will reduce energy costs in both markets."[115] And STOP B2H further asserts, "If both regions build renewables to meet their resource inadequacies, a new large transmission system will not be needed."[116] This is simply not the case. Idaho Power's primary goal is not to avoid a large new transmission line but

[114] STOP B2H/100, Kreider/4 (Jan. 17, 2023).
[115] STOP B2H/100, Kreider/4 (Jan. 17, 2023).
[116] STOP B2H/100, Kreider/4 (Jan. 17, 2023).

rather to meet customers' electricity needs in the most economic manner and eventually with 100 percent clean energy. This means not only meeting new demand, including demand caused by electrification, but eventually replacing all *existing* carbon emitting resources as well. Idaho Power cannot do this in a silo; the wind is not always blowing and the sun is not always shining across Idaho Power's footprint. Geographical diversity of loads and resources is key in a renewable energy future, as even the best renewable resource in a single area is inferior to diverse renewable resources in a broad and geographically diverse area. Acquiring renewables in Idaho alone is not a feasible alternative to B2H.

This can be further exemplified under a 50 percent renewable portfolio standard ("RPS") target as an example. The Company's all-time peak load is 3,751 MW and its average load is approximately 1,900 average megawatts ("aMW"). Meeting a 50 percent RPS would require 950 aMW of renewable generation. In terms of solar, at a 28 percent capacity factor, the Company would have to install about 3,400 MW of solar simply to achieve the 50 percent RPS threshold. That is a solar resource nameplate just shy of the Company's all-time peak, and that is only to achieve an RPS of 50 percent. STOP B2H's suggestions fall short of meeting the goals of the State of Oregon. An all-of-the-above approach, including expanded regional transmission connections, is required to meet deep decarbonization scenarios. The need for significantly more transmission is supported by various studies across the United States.[117]

Q. Are there other alternatives to B2H that STOP B2H is recommending?

A. STOP B2H suggests the following alternatives that I will address individually: (1) upgrading, digitizing, and fire hardening the three existing 230-kV lines between the

[117] *See generally* Idaho Power/203, Barretto/480-899 (Northern Tier Transmission Group and NorthernGrid Regional Transmission Plans 2007-2021).

Pacific Northwest and Idaho,[118] (2) increased energy efficiency targets,[119] (3) more robust demand-side management programs,[120] (4) co-generation with commercial and industrial customers,[121] (5) aggressive roll-out of smart grid technologies while partnering with customers,[122] (6) securing or building more renewable generation close to load/demand and existing substations,[123] and (7) battery storage and ancillary services.[124]

Q. Is upgrading, digitizing, and fire hardening the three existing 230-kV lines a feasible alternative?

A. No. In my Direct Testimony, I presented a table titled "Comparison of Transmission Line Capacity Scenarios – Rebuild Existing Lines to the Northwest."[125] Upgrading these lines was the first alternative that Idaho Power explored. These three 230-kV lines extend from: (1) Brownlee to La Grande to McNary, (2) Brownlee to Walla Walla, and (3) Brownlee to Lolo (near Lewiston, Idaho). Rebuilding or upgrading these lines alone would not result in any incremental capacity gains without upgrading lines (or building a new line) from Brownlee to Boise as well. Financially, this result would be imprudent, as it would result in more cost, be less reliable, and unlock less capacity than a new 500-kV transmission line unless all lines are rebuilt at 500-kV, which would further increase costs. The Brownlee to Walla Walla and Brownlee to Lolo lines share a common tower (i.e. double circuit 230-kV). The Company is required, per North American Electric Reliability Corporation standards, to study the simultaneous loss of two transmission circuits on a common tower. This limits the effectiveness of a rebuild along that route through Hells Canyon. The table previously referenced assumed a new line route could be acquired

[118] STOP B2H/100, Kreider/7 (Jan. 17, 2023).
[119] STOP B2H/100, Kreider/6 (Jan. 17, 2023).
[120] STOP B2H/100, Kreider/6 (Jan. 17, 2023).
[121] STOP B2H/100, Kreider/6 (Jan. 17, 2023).
[122] STOP B2H/100, Kreider/6 (Jan. 17, 2023).
[123] STOP B2H/100, Kreider/6 (Jan. 17, 2023).
[124] STOP B2H/100, Kreider/6 (Jan. 17, 2023).
[125] Idaho Power/100, Ellsworth/22 (Sept. 30, 2022).

through the Hells Canyon area, which the Company had explored in the 1990's and considered highly wrought with challenges.

Q. What alternatives proposed by STOP B2H has Idaho Power evaluated as part of the IRP process?

A. Increased energy efficiency, demand-side management, co-generation with commercial and industrial customers, and smart grid technologies are certainly all options to meet the Company's needs and evaluated as part of the IRP process.[126] These can be both competing alternatives to B2H, and complementary to B2H, as part of a total resource portfolio in the Company's IRP. Energy efficiency and demand-response are components of the Company's 2021 IRP Preferred Portfolio, which also includes B2H.[127] Idaho Power has one of the largest demand-response programs in the nation compared to its load, and it will continue to add demand response in the coming years. Customers currently have the option to build co-generation and sell it back to the Company as a PURPA project. The Company is open to considering feasible co-generation opportunities and would incorporate these into the IRP modeling once presented. Smart grid technologies are a broad category of solutions to various problems utilities face. Focusing on resource-adequacy-related smart grid items, STOP B2H mentions Advanced Metering Infrastructures and two-way communications with customers,[128] which may better be a component of the demand-response category.

Q. Did Idaho Power evaluate securing and building more renewables close to load or battery storage as an alternative to B2H?

A. Yes. Securing and building more renewables close to load, as well as battery storage, were analyzed as part of the Company's 2021 IRP Preferred Portfolio as indicated by the

[126] *See, e.g.*, 2021 IRP at 93-103 (summarizing demand-side resources analyzed in the IRP process).

[127] 2021 IRP at 193 (detailing the energy efficiency components of the preferred portfolio).

[128] STOP B2H/100, Kreider/4 (Jan. 17, 2023).

approximately 700 MW of wind, 1,400 MW of solar, and 1,700 of battery storage that are included. All alternatives proposed by STOP B2H have been considered and discussed in various other dockets. Additionally, many items STOP B2H listed are components of the Company's 2021 IRP Preferred Portfolio.

It is important also to recognize that BPA and PacifiCorp's needs are a consideration as well. B2H meets all parties' needs holistically, providing for a robust project. Absent B2H, Idaho Power's customer costs would increase in comparison to a B2H solution. BPA's costs would increase significantly, their customers would have uncertainty, and reliability would be in question, and PacifiCorp's costs would increase, and its plans to move renewable energy across its large footprint, and meet Oregon and Washington clean energy mandates would have to be reoptimized to a lesser solution.

C. Mr. Greg Larkin

Q: Mr. Larkin identifies "failure[s] of Idaho Power" in his Opening Testimony.[129] Do you agree with the failures identified?

A: No. Mr. Larkin states the Company failed to:

> justify the costs, the ability of Idaho Power to obtain more reasonably priced renewable energy by supporting developments within Idaho which would not necessitate this transmission line, the fact that it will discourage renewable energy development and conservation in Idaho, the lack of a need or benefit to Oregon citizens and electric customers[.]

With respect to costs, as I described above, Idaho Power justified the cost of the B2H project in its 2021 IRP, identifying the Preferred Portfolio, which includes B2H, as $266 million more cost-effective than the least-cost non-B2H portfolio.[130] The Commission acknowledged Idaho Power's 2021 IRP on January 13, 2023, with Order No. 23-004.[131]

[129] Greg Larkin's Amended Opening Testimony and Exhibits of Greg Larkin (Greg Larkin/100, Larkin/1) (Feb. 1, 2023).

[130] 2021 IRP, Appendix D at 8.

[131] *In re Idaho Power Company, 2021 IRP*, Docket LC 78, Order No. 23-004 at 1 (Jan. 13, 2023).

It is not clear what additional justification Mr. Larkin is seeking.

Q. Does the Company believe it can obtain more reasonably priced renewable energy within Idaho at a cost lower than B2H?

A. No. Idaho Power identified significant renewable resource needs within its existing transmission footprint as part of its 2021 IRP. These resources were evaluated against, and with, B2H,[132] the results of which determined that a portfolio inclusive of B2H, and internal resources, was the most optimal least-cost, least-risk portfolio.[133]

Q. Does Idaho Power discourage renewable energy development and conservation in Idaho?

A. No. The Company's 2021 IRP Preferred Portfolio includes approximately 700 MW of wind and 1,400 MW of solar.[134] These represent significant potential additions for Idaho Power, with many of these resources likely being sited in Idaho. The Company does not discourage renewable development contrary to Mr. Larkin's belief. In fact, in the short term the Company expects 120 MW of new battery storage to come online in 2023, and on Friday, February 17, 2023, notified the Commission of its intent to acquire an additional 72 MW of battery storage while entering into a PPA for a 100 MW solar project.[135] All of these projects are located within the state of Idaho. Additionally, it is likely that PacifiCorp will also *increase* its Idaho renewable investments due to B2H and the availability of capacity. With respect to conservation, Idaho Power executes on all cost-effective energy efficiency and demand response.

Q. Has the Company identified the Project's benefit to Oregon citizens and customers?

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[132] 2021 IRP at 80-84.
[133] 2021 IRP at 192.
[134] 2021 IRP at 192.
[135] *In re Idaho Power Company, Application for Approval of 2026 All-Source Request for Proposals to Meet 2026 Capacity Resource Need*, Docket UM 2255, Idaho Power Company's Notice of Exception Report Under OAR 860-089-0100 at 1 (Feb. 17, 2023).

A. Yes. As I discussed earlier in my testimony, the State of Oregon will experience numerous benefits associated with B2H. The Project will reduce costs to BPA customers who serve numerous utility customers across Oregon. It will enable additional load service into Central Oregon for PacifiCorp while also freeing up capacity for BPA to meet the needs of its customers in Eastern Oregon. B2H is the most cost-effective solution for Idaho Power's customers in Eastern Oregon. Finally, the Project will increase Oregon's transmission import capability by 1,000 MW initially, and likely 2,000 MW after the addition of Gateway West, providing a major resiliency benefit to the State of Oregon during extreme weather conditions.

Q. Mr. Larkin compares BPA purchasing power from the market, which BPA views as higher risk, to Idaho Power purchasing power from the market.[136] Are these comparable?

A. No. BPA is a federal agency in control of enormous amounts of very low-cost hydro power. Today, due to transmission limitations in the absence of B2H, BPA must purchase power from southern markets to serve their customers in Southeast Idaho, and as a result experience exposure to gas markets, scarcity pricing, etc. The alternative BPA desires, and will achieve with B2H, is to serve their customers with their own very low-cost hydro resources. By using their own resources, BPA will reduce costs for all BPA customers, including BPA customers in Oregon. It is ill-conceived to suggest that the Company should adopt a similar approach because Idaho Power does not have such large amounts of hydro resource capacity at its disposal.

Q. Mr. Larkin asserts Idaho Power will be relying on B2H primarily to transmit energy produced in Oregon out of the state.[137] Is that assumption correct?

A. No. Idaho Power intends to primarily purchase power from the Mid-C market but will

[136] Greg Larkin/100, Larkin/9 (Feb. 1, 2023).
[137] Greg Larkin/100, Larkin/7 (Feb. 1, 2023).

transact with any cost-effective entity able to deliver power to Mid-C, the Longhorn substation, or the Four Corner substation. Focusing on Mid-C, numerous entities spread across the entire west transact at the Mid-C, benefiting various regions, as will be the case with B2H.

Q. Will Oregon need energy transmitted across B2H?

A. Yes. During winter peak periods on the existing system, the transmission connections between Idaho and the Pacific Northwest can reach their maximum flow ratings sending power into the Pacific Northwest. Now consider a future with more electrification, and therefore more winter demand, and potentially fewer thermal resources to meet the needs of the Pacific Northwest. One of the critical components to a clean energy future is the ability to import power from regions experiencing different weather patterns. As discussed above, Oregon is small enough geographically that a singular weather pattern can impact the entire state and reduce the energy output of wind and solar resources for extended periods. Mr. Larkin states "Oregon generates an adequate supply of electricity to meet current as well as future increased needs, and are exporting electricity without having to build any additional energy developments."[138] However, Mr. Larkin's analysis is flawed as it appears to be based on power systems from an annual energy basis, when in reality, power is both produced and consumed on a near-instantaneous basis.

Q. Does Mr. Larkin understand the B2H-related arrangements contemplated between Idaho Power, BPA, and PacifiCorp?

A. No, I don't believe so. In his Opening Testimony, Mr. Larkin states:

> Idaho Power has only submitted information regarding a need for 25% of the transmission line which includes moving energy out of Oregon to sell on a wholesale basis to out of state customers. They also include an inaccurate statement that the transmission line is needed to move energy from Idaho to Oregon when production of in-state electricity is not meeting Oregon's need. They are now

[138] Greg Larkin/100, Larkin/11-12 (Feb. 1, 2023).

> saying they will absorb the costs and use 50% of the development of the Boardman to Hemingway line with no supporting justification for this need or cost. They are claiming that they can sell part of their share to some other unknown utility in their Non-Binding agreement.[139]

Idaho Power's need for the Project is currently based on a 45 percent ownership structure,[140] and these costs were modeled accordingly in the Company's 2021 IRP.[141] Idaho Power will generally purchase energy from Mid-C, of which Oregon utilities will likely provide a subset of that energy. Oregon utilities will also have additional opportunities to purchase power from southern markets via B2H, providing value to the State of Oregon, as I have previously discussed. The Company has provided information to support an increased ownership share in B2H in both Docket No. LC 74 (the Company's 2019 IRP)[142] and Docket No. LC 78 (the Company's 2021 IRP). Idaho Power provided substantial information regarding the need and cost in those dockets. Mr. Larkin further criticizes the proposed ownership structure, indicating that "[n]o one is stepping forward to commit to this cost and use of the transmission line,"[143] yet as evidenced earlier in my testimony, all agreements necessary to memorialize the ownership structure are nearly complete. Mr. Larkin's statements are grossly inaccurate.

Q. Does Mr. Larkin reach any other erroneous conclusions?

A. Yes. To identify and clarify additional misrepresentations or poor conclusions made by Mr. Larkin, I will first provide the statement made by Mr. Larkin and follow it with facts.

- "Oregon electricity users can be expected to be forced to pay increased costs to compensate for the costs of between 50% and 75% of this transmission line

[139] Greg Larkin/100, Larkin/22-23 (Feb. 1, 2023).
[140] Term Sheet at 470.
[141] 2021 IRP at 116.
[142] *In re Idaho Power Company's 2019 IRP*, Docket LC 74, Second Amended 2019 IRP at 19 (filed Oct. 2, 2020).
[143] Greg Larkin/100, Larkin/29 (Feb. 1, 2023).

either directly or indirectly with minimal or no benefit from it."[144] It is not clear why Mr. Larkin believes that *Oregon electricity users* will end up paying 50 percent to 75 percent of the transmission line. Idaho Power's customers, including BPA, will cover 45 percent of the cost of the project. Any Idaho Power OATT rate increases are already factored into BPA's business case which, as I mentioned earlier, shows $720 million in savings to its customers, many of whom are located in Oregon. PacifiCorp and its customers will fund 55 percent of the cost of the project. Some of PacifiCorp's costs will likely be assigned to Oregon customers, but comparatively less than non-B2H alternatives, as evidenced in PacifiCorp's business case discussed earlier.

- "[N]o other group has filed Integrated Resource Plans documenting a need for 50% of the capacity of the line."[145] In fact, PacifiCorp included B2H in its 2021 IRP Preferred Portfolio.
- "PUC staff have gone on record stating that the proposal, including the transmission line; is basically equal to other plans."[146] The Company is unaware of any such reference.
- "Idaho Power has not provided information regarding the ability of existing transmission lines to carry the energy they indicate they need through hardening of existing lines[.]"[147] In fact, Idaho Power provided this information as part of the Energy Facility Siting Council proceeding and was summarized in my Direct Testimony.[148]
- "The cost figures being provided by Idaho Power are not believable. The costs

[144] Greg Larkin/100, Larkin/30 (Feb. 1, 2023).
[145] Greg Larkin/100, Larkin/31-32 (Feb. 1, 2023).
[146] Greg Larkin/100, Larkin/32 (Feb. 1, 2023).
[147] Greg Larkin/100, Larkin/32 (Feb. 1, 2023).
[148] Idaho Power/100, Ellsworth/21-23 (Sept. 30, 2022).

of every item and employee being used to construct this transmission line have experienced significant increases since 2016."[149] Ms. Barretto's Supplemental Testimony filed on December 30, 2022, included a revised B2H cost estimate based on the latest forecast.[150] As I discussed earlier, the revised cost estimate indicates a difference of $228 million between the least-cost B2H portfolio and the least-cost non-B2H portfolio. The B2H portfolio remains the most optimal least-cost, least-risk portfolio.

Q. Does this complete your testimony?

A. Yes, it does.

[149] Greg Larkin/100, Larkin/32 (Feb. 1, 2023).

[150] Idaho Power's Supplemental Direct Testimony of Lindsay Barretto (Idaho Power/300, Barretto/1-4) (Dec. 30, 2022).

Idaho Power/501
Witness: Jared L. Ellsworth

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

Docket PCN 5

In the Matter of

IDAHO POWER COMPANY'S
PETITION FOR CERTIFICATE OF PUBLIC CONVENIENCE
AND NECESSITY

Construction, Ownership, Operation, Asset Exchanges
and Service Agreements Necessary for B2H

REDACTED

February 21, 2023

IDAHO POWER

Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for the Boardman to Hemingway Project

	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
1	**Second Amended and Restated Boardman to Hemingway ("B2H") Transmission Project Joint Permit Funding Agreement**	§ 3(a)(14)	Idaho Power and PacifiCorp	The Amended and Restated Joint Permit Funding Agreement provides definitive terms and conditions by which Idaho Power, PacifiCorp and Bonneville Power Administration ("BPA") jointly support and contribute funds to the processes associated with obtaining necessary governmental authorizations and completing other necessary work to permit, site, and acquire Rights-of-Way for the B2H project. The second amendment recognizes the reallocation of the parties' permitting interest and related funding obligations following the transfer of BPA's permitting interest to Idaho Power, providing the definitive terms and conditions by which Idaho Power and PacifiCorp will continue jointly supporting and contributing funds. Upon execution, Idaho Power's permitting interest will increase to 45.45% and PacifiCorp's permitting interest remains at 54.55%.	Following BPA Public Process, March 2023
2	**Network Integration Transmission Service Agreement ("NITSA") for Goshen Load**	§ 3(b)(1)	Idaho Power and BPA	This agreement will allow for Idaho Power to provide firm network transmission service to BPA's customers at Goshen. The term of the NITSA will be 20-years from energization of the B2H project, with a renewal or rollover option at BPA's discretion as required and permitted by the Federal Energy Regulatory Commission ("FERC"). BPA will pay Idaho Power's Network Transmission Service rates as established under Attachment H of the Company's Open Access Transmission Tariff ("OATT").	Following BPA Public Process, March 2023
3	**NITSA for Idaho Falls Load**	§ 3(b)(1)	Idaho Power and BPA	This NITSA will allow for Idaho Power to provide firm network transmission service to BPA's customers at Idaho Falls. The term of the NITSA will be 20-years from energization of the B2H project, with a renewal or rollover option at BPA's discretion as required and permitted by the FERC. BPA will pay Idaho Power's Network Transmission Service rates as established under Attachment H of the Company's OATT.	Following BPA Public Process, March 2023

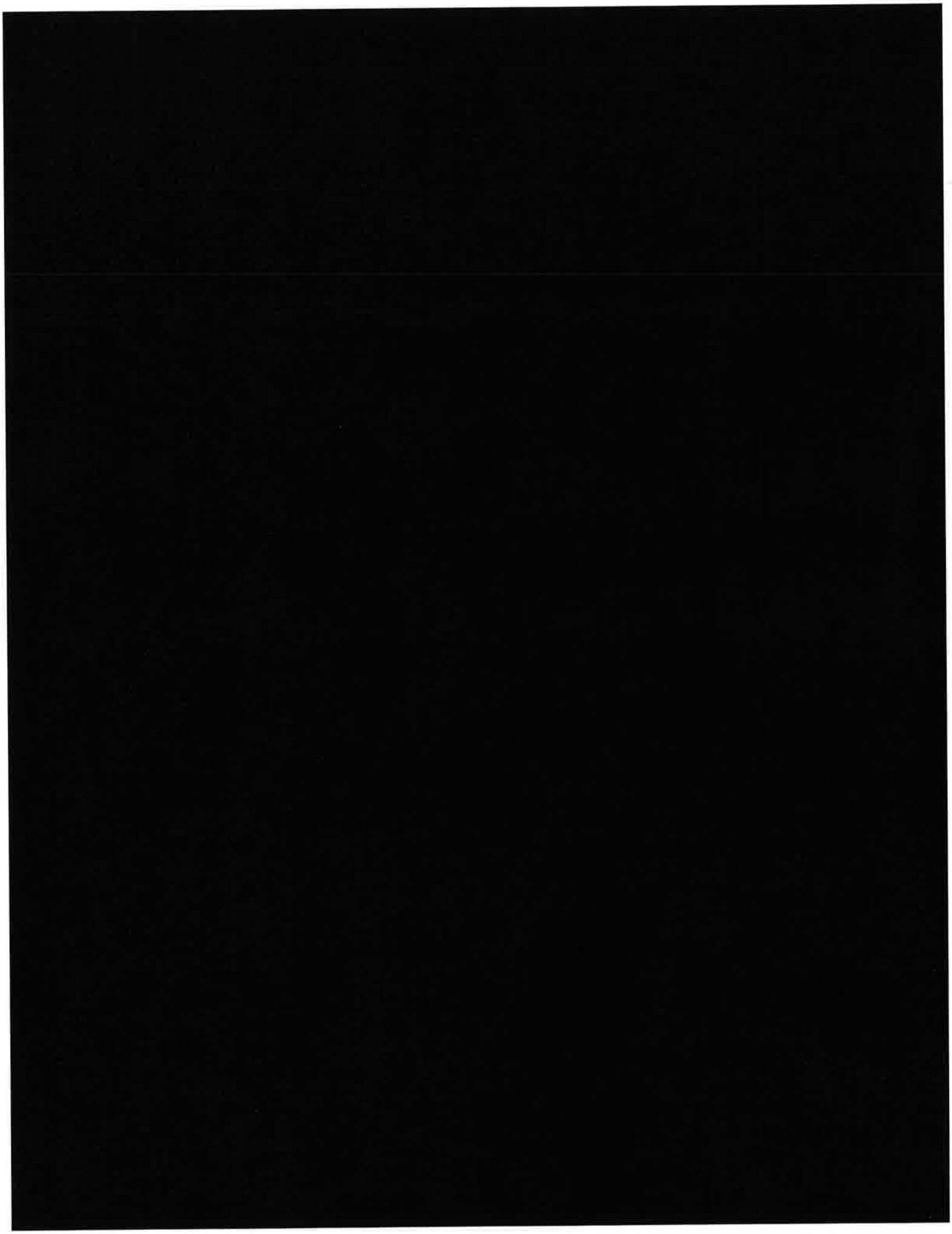
	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
4	**Purchase, Sale, and Security Agreement**	§ 3(b)(2) and § 3(b)(3)	Idaho Power and BPA	The Purchase, Sale, and Security Agreement provides for the transfer by BPA to Idaho Power of BPA's permitting interest in the B2H project under the Joint Permitting Agreement. Provisions include: • Idaho Power's reimbursement to BPA for the transfer of BPA's permitting interest in an amount consisting of BPA's investment in the B2H project prior to the transfer date ("Transferred Permitting Interest"). • BPA's security payment to Idaho Power of an additional $10 million ("Seller's Security"). • Accrual of interest on both the Transferred Permitting Interest and Seller's Security, payable by Idaho Power to BPA, from the date of energization of B2H, at a rate of 3.25% compounded annually. • The repayment by Idaho Power to BPA of the Seller's Security plus all accrued interest will occur within 60 days following energization of B2H. • The repayment by Idaho Power to BPA of the Transferred Permitting Interest plus all accrued interest will begin: o Starting year 11 following B2H energization of B2H if the total load of the NITSAs for any rolling twelve-month basis averages 400 MW or more prior to the tenth anniversary of energization ("Repayment Event"), or o The next anniversary date of energization following the Repayment Event if the total load of the NITSAs for any rolling twelve-month basis averages 400 MW or more after the tenth anniversary of B2H energization. • Once repayment of the Transferred Permitting Interest begins, Idaho Power will make monthly payments to BPA starting at $40,000 per month for the first twelve-month interval and increase by $40,000 for each successive twelve-month interval. • Should Idaho Power not receive all governmental authorizations including permits and Certificates of Public Convenience and Necessity ("CPCN") or decides to delay or not to proceed with further development or construction of the B2H project, by January 1, 2025, Idaho Power will return to BPA the Seller's Security.	Following BPA Public Process, March 2023

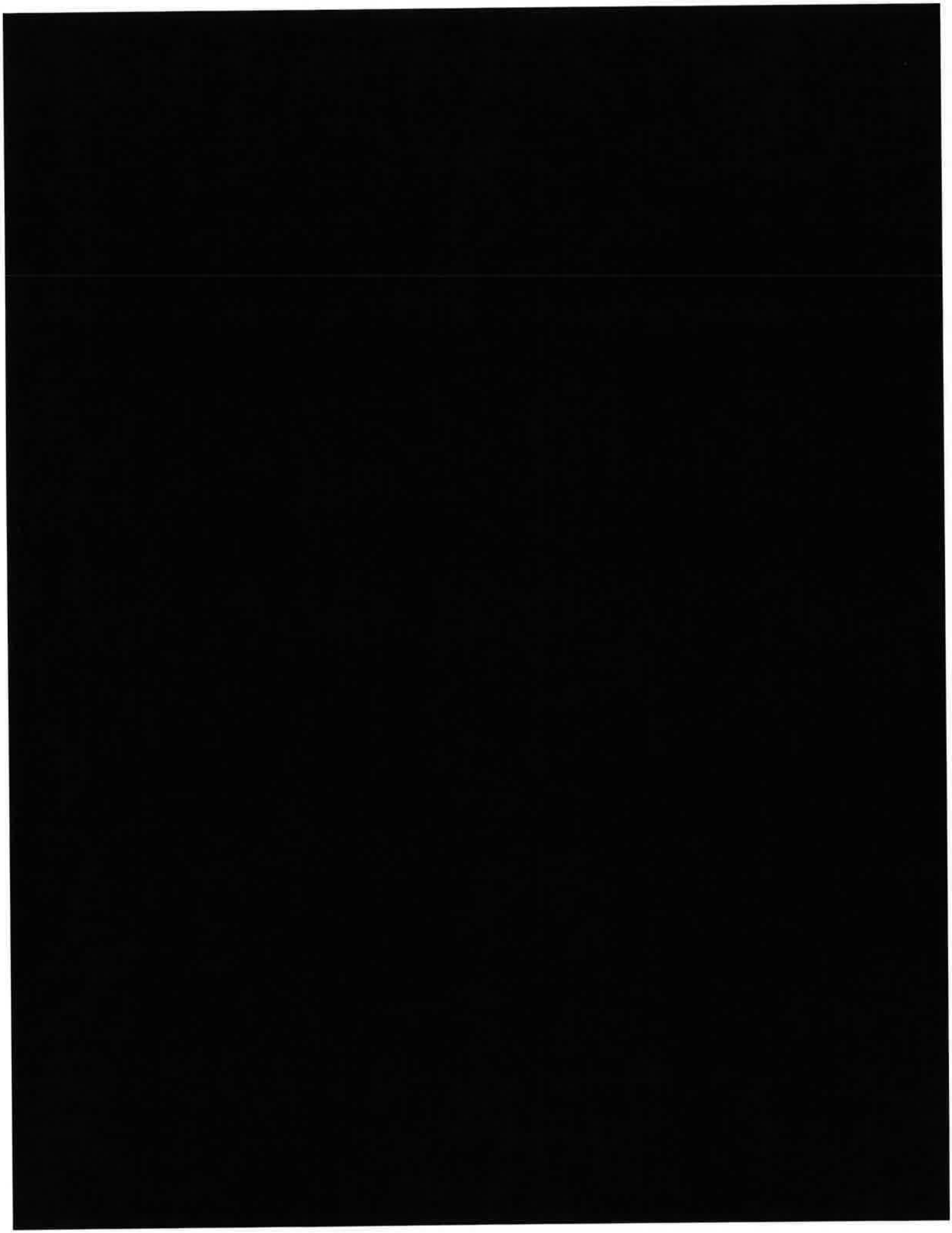
	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
5	**Joint Purchase and Sale Agreement ("JPSA")**	§ 3(a)(5) and § 3(a)(7)	Idaho Power and PacifiCorp	Idaho Power and PacifiCorp desired to exchange undivided ownership interests in certain transmission assets to provide transmission capacity that better aligns with the current configuration of the parties' respective future needs following the addition of B2H. The JPSA facilitates these asset exchanges and is contingent upon regulatory approvals for both parties. Under the purchase and sale provisions: • PacifiCorp will convey to Idaho Power an ownership interest in identified Four Corners/Populus assets, • PacifiCorp will convey to Idaho Power an ownership interest in identified Goshen area assets, • Idaho Power will convey to PacifiCorp an ownership interest in identified Borah/Midpoint West assets, • The purchase price of the assets being conveyed will be equal to the conveying party's net book value, and • Acquired assets of both parties will be operated and maintained in accordance with the Second Amended and Restated Joint Ownership and Operating Agreement ("JOOA"). In addition, the JPSA identifies the following conditions precedent upon closing of the JPSA: • PacifiCorp will release to Idaho Power 200 MW of bidirectional transmission rights on the Four Corners/Populus assets, • Idaho Power will transfer to PacifiCorp 300 MW of west-to-east firm, PTP transmission service between Midpoint and Borah, and • Idaho Power will transfer to PacifiCorp 600 MW of east-to-west firm, PTP transmission service between Borah and Hemingway.	Following BPA Public Process, March 2023

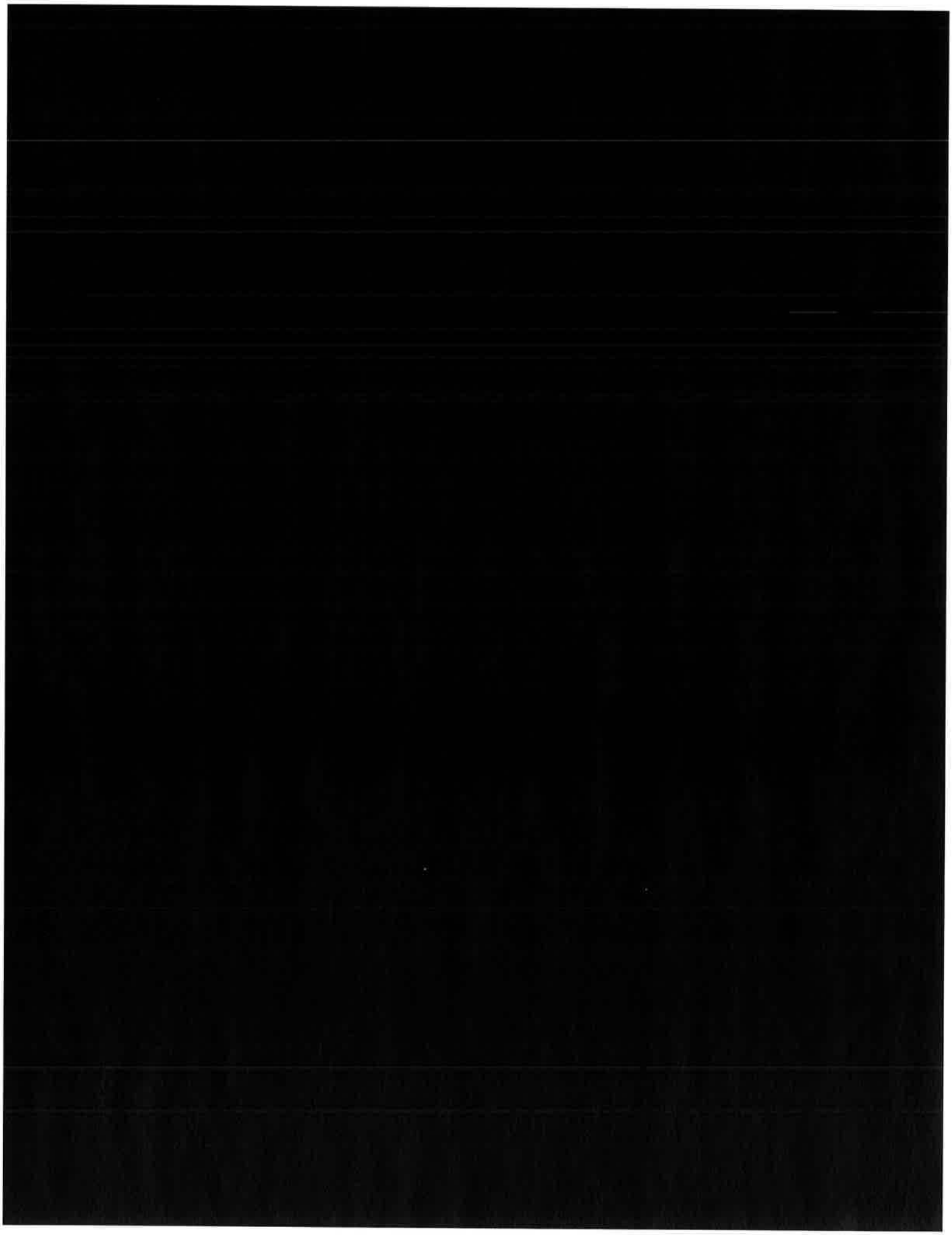
	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
6	**Second Amended and Restated JOOA**	§ 3(a)(6) and § 3(c)	Idaho Power and PacifiCorp	Idaho Power and PacifiCorp will expand the existing JOOA, as amended and restated August 22, 2019, to include ownership, operation and maintenance provisions associated with the B2H project. In addition, as a condition precedent to closing of the purchase and sale transactions identified in the JPSA, the Second Amended and Restated JOOA will include operation and maintenance provisions associated with the assets acquired by both parties under the JPSA: • The 300 MW of west-to-east transmission assets between Midpoint 500 and Borah, • The 600 MW of east-to-west transmission assets between Borah and Hemingway, • The 200 MW of bi-directional transmission assets between Populus, Mona and Four Corners, and • The Goshen area assets necessary to serve BPA load.	To be drafted, to be effective upon energization of B2H
7	**Boardman to Hemingway Transmission Project Joint Construction Funding Agreement**	§ 3(a)(10), § 3(a)(12), and § 3(d)	Idaho Power and PacifiCorp	This agreement will provide definitive terms and conditions by which Idaho Power and PacifiCorp will jointly support and contribute funds, for the procurement, construction, and commissioning of the B2H project, to allow for energization of the project by the earliest in-service date needed by the parties. In addition, it appoints Idaho Power as the construction project manager, providing for full power and authority to do all things necessary or proper to develop and construct the B2H project. The Midline Series Capacitor Project Funding Agreement identified in § 3(a)(12) of the Term Sheet was initially as a separate agreement but has been subsequently incorporated into the overall construction plan for B2H. The work will include installation of the Midline Series Capacitor substation, which is necessary to reduce simultaneous interactions between the NW AC Intertie, central and southern Oregon load service, and Path 14 (Idaho to Northwest).	To be drafted, not required for BPA Public Process, July 2023

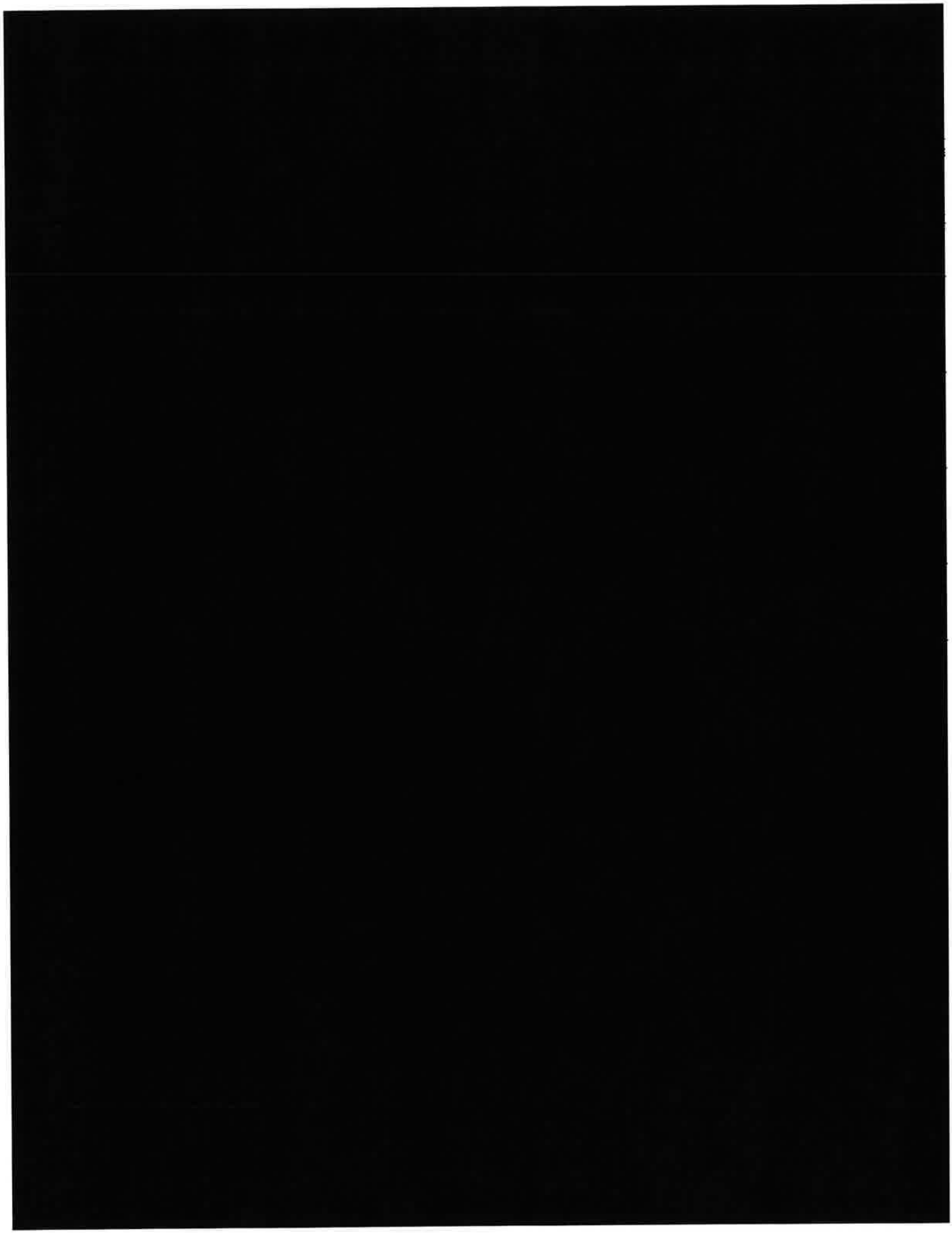
	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
8	**Longhorn Substation Funding Agreement**	§ 3(a)(4)	Idaho Power, BPA and PacifiCorp	As outlined in the conditions precedent to closing of the JPSA, PacifiCorp, Idaho Power and BPA will enter into an agreement for the Longhorn substation for the funding by Idaho Power and PacifiCorp of a portion of the assets at and directly adjacent to the Longhorn substation near Boardman, Oregon, where B2H will interconnect. Provisions include: • A use of facilities charge or other charge pursuant to BPA's OATT to be paid by Idaho Power and PacifiCorp to allow the parties to transact across the Longhorn bus in the future (if necessary, and at the future discretion of Idaho Power and PacifiCorp), and • Ownership, operation, and maintenance of B2H equipment by Idaho Power and PacifiCorp, including (1) a B2H project-related series capacitor at the Longhorn substation, (2) the B2H project shunt line reactors at Longhorn, and (3) any ancillary equipment required to support the B2H project series capacitor and shunt line reactors. The agreement will be contingent upon BPA completing its obligations and responsibilities under various environmental compliance laws.	To be drafted, not required for BPA Public Process, March 2023
9	**Midpoint 500/345-kV Transformer Project Construction Agreement ("Midpoint Transformer Construction Agreement")**	§ 3(a)(5)	Idaho Power and PacifiCorp	Under the Midpoint Transformer Construction Agreement, and in conjunction with the JPSA, Idaho Power will make capital upgrades to the Midpoint 500-kV and 345-kV transmission substations, including a second 500/345-kV transformer bank and 345-kV tie line. The assets will be jointly owned by the parties as illustrated in Exhibit A of the JPSA and in accordance with the Second Amended and Restated JOOA.	To be drafted, not required for BPA Public Process, March 2023
10	**Kinport – Midpoint 345-kV Series Capacitor Bank Project Construction Agreement ("Kinport Capacitor Bank Construction Agreement")**	§ 3(a)(5)	Idaho Power and PacifiCorp	Under the Kinport Capacitor Bank Construction Agreement, and in conjunction with the JPSA, Idaho Power will make capital upgrades to the Midpoint 345-kV transmission line, by installing the Kinport-Midpoint 345-kV Series Capacitor Bank. The assets will be jointly owned by the parties as illustrated in Exhibit A of the JPSA and in accordance with the Second Amended and Restated JOOA.	To be drafted, not required for BPA Public Process, March 2023

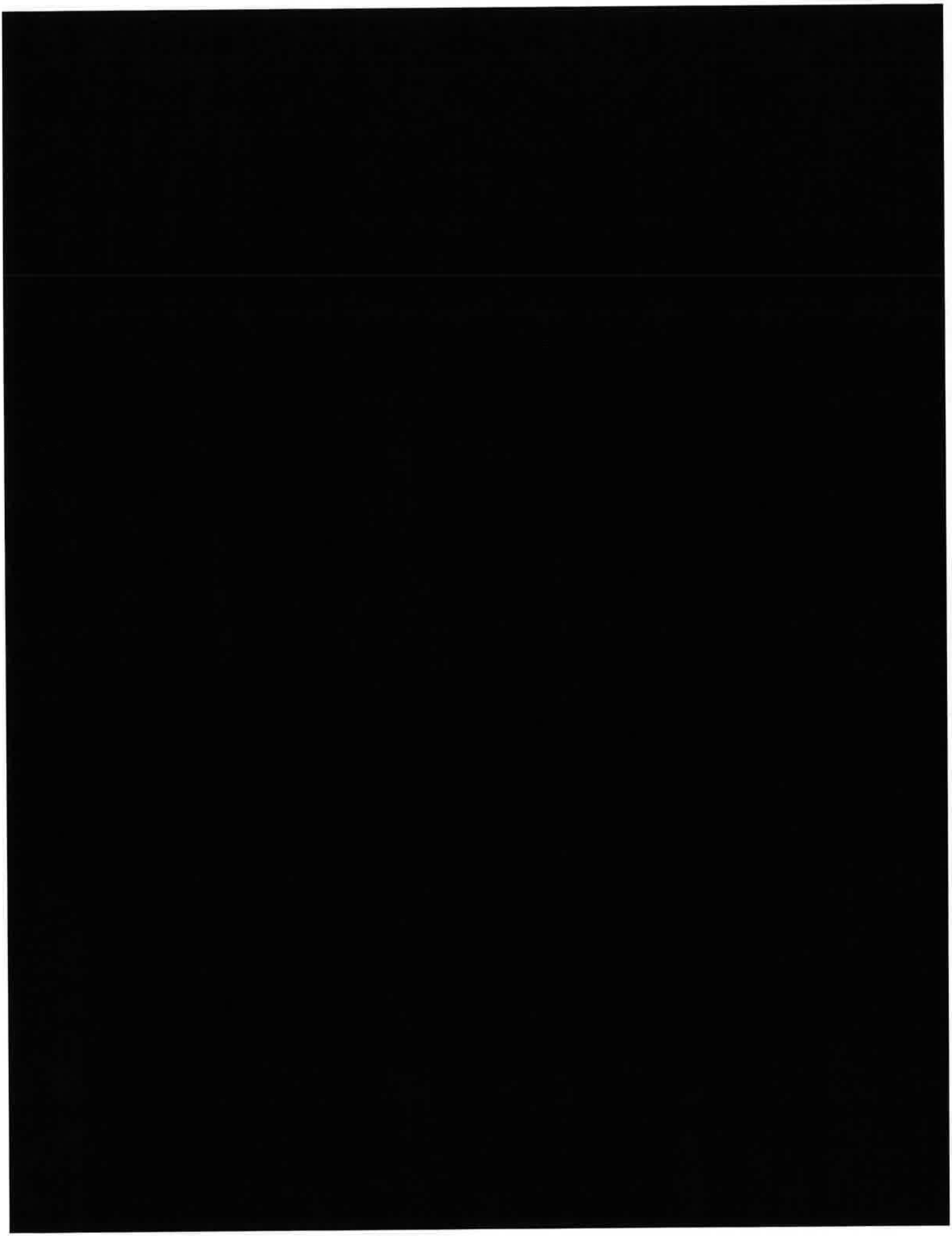
	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
11	**Transmission Service Agreements**	§ 3(a)(8), § 3(a)(9) and § 3(a)(11)	Idaho Power, PacifiCorp, and/or BPA	The following transmission service requests will be executed or changes to existing transmission services agreements will be made: • Idaho Power will acquire from BPA 500 MW of point-to-point ("PTP") transmission service from Mid-C to Longhorn, • PacifiCorp will renew its 510 MW of PTP transmission service from Idaho Power, • BPA will redirect its two 100 MW PTP transmission service agreements that it takes from Idaho Power and assign to PacifiCorp.	Not required for BPA Public Process, March 2023

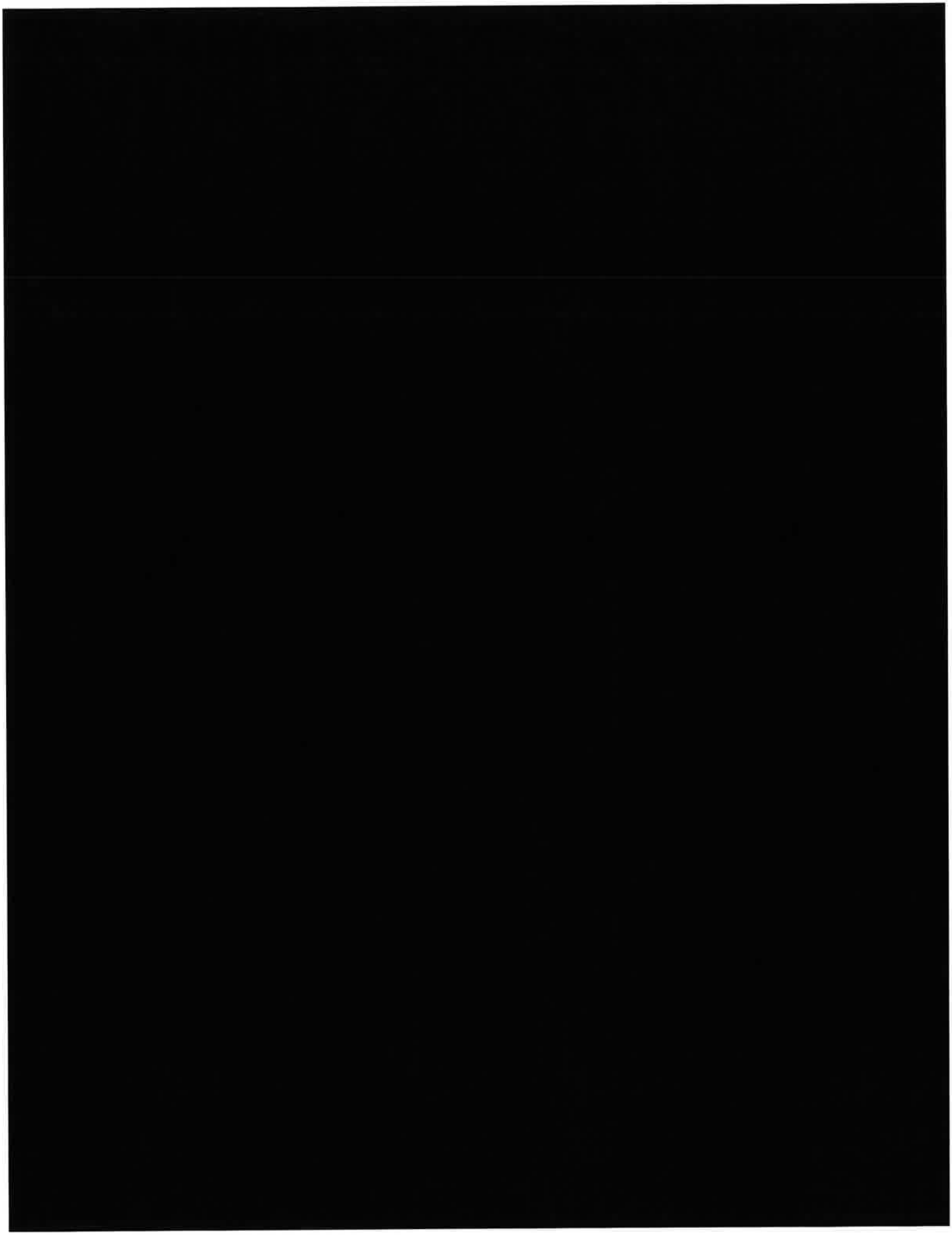


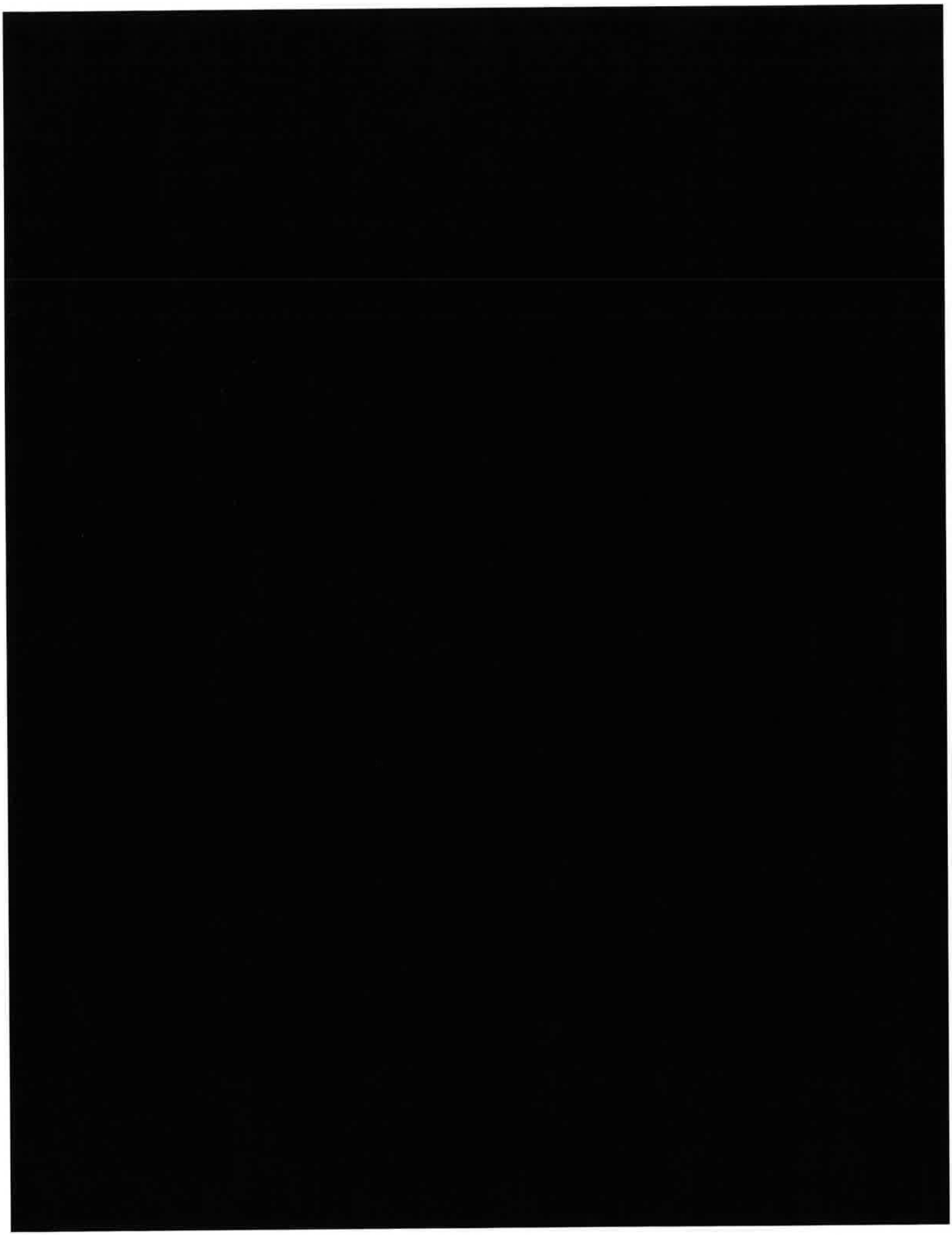


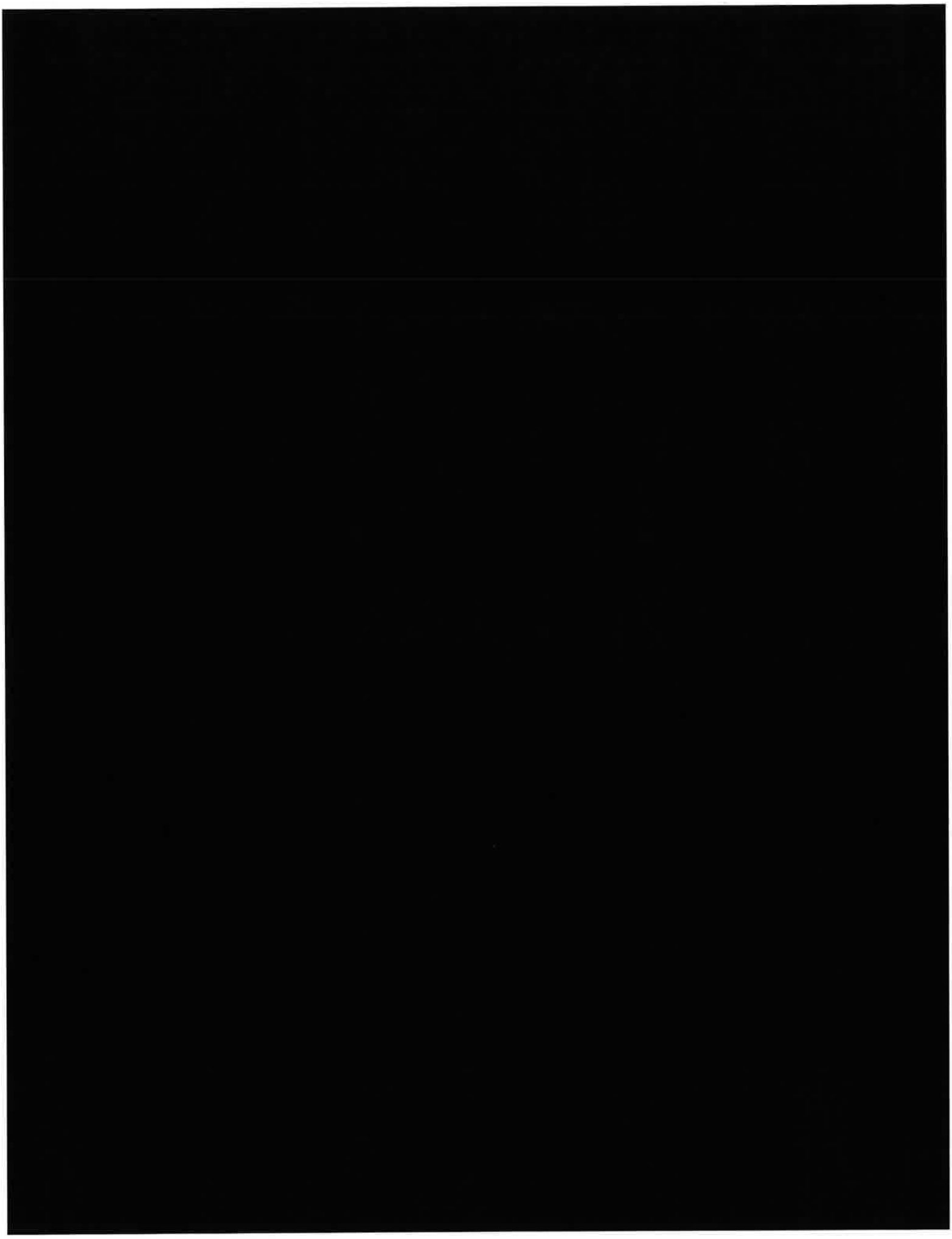


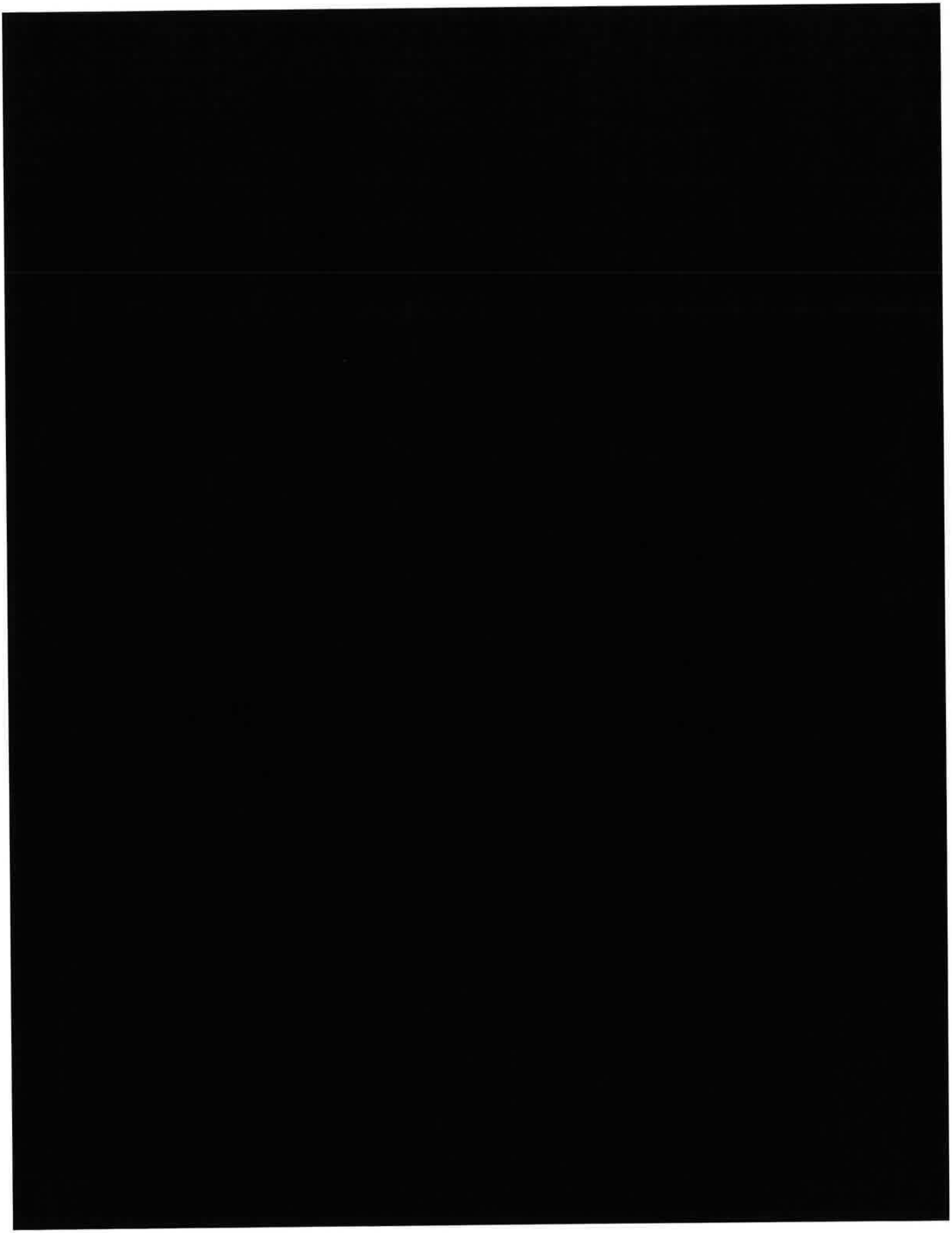


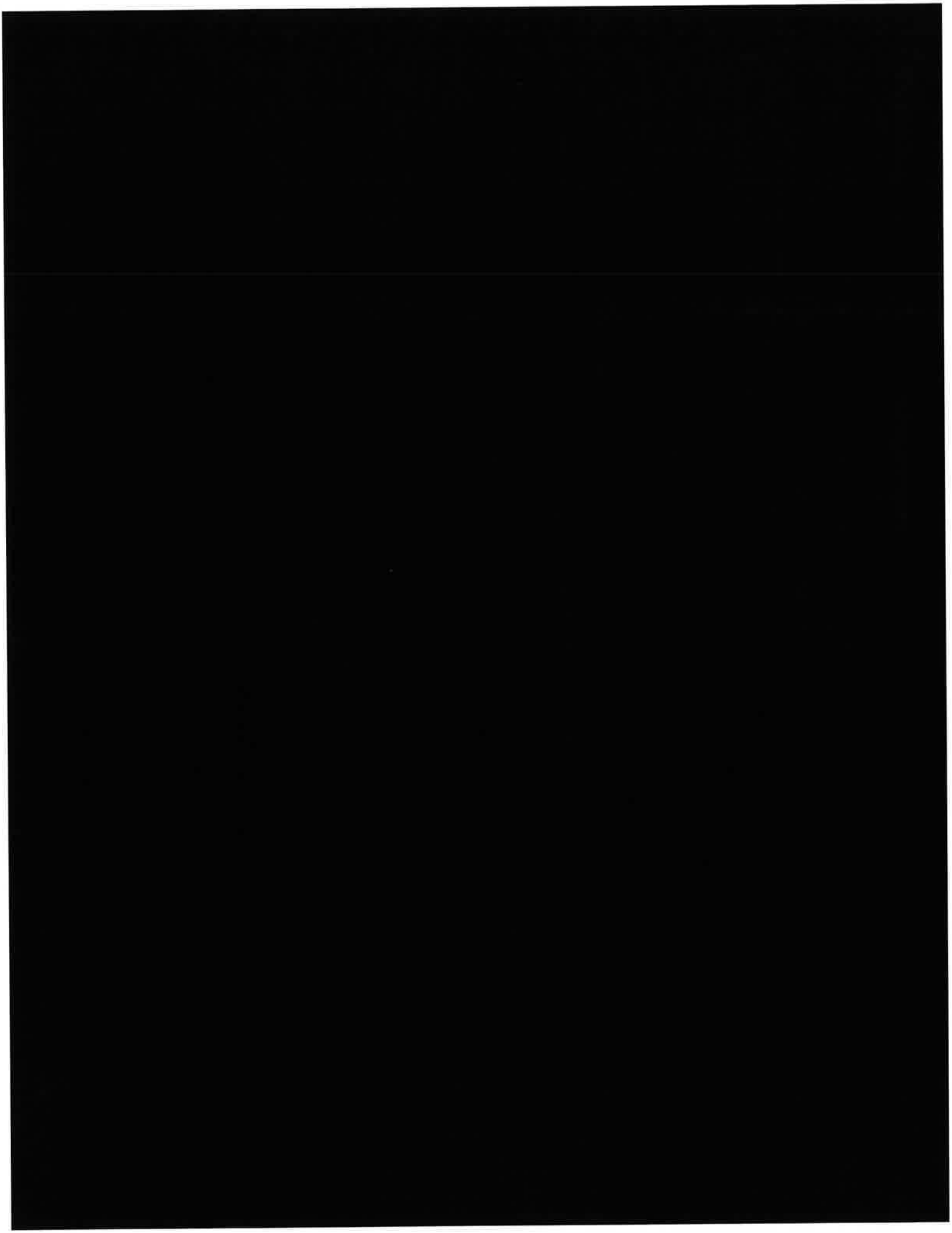


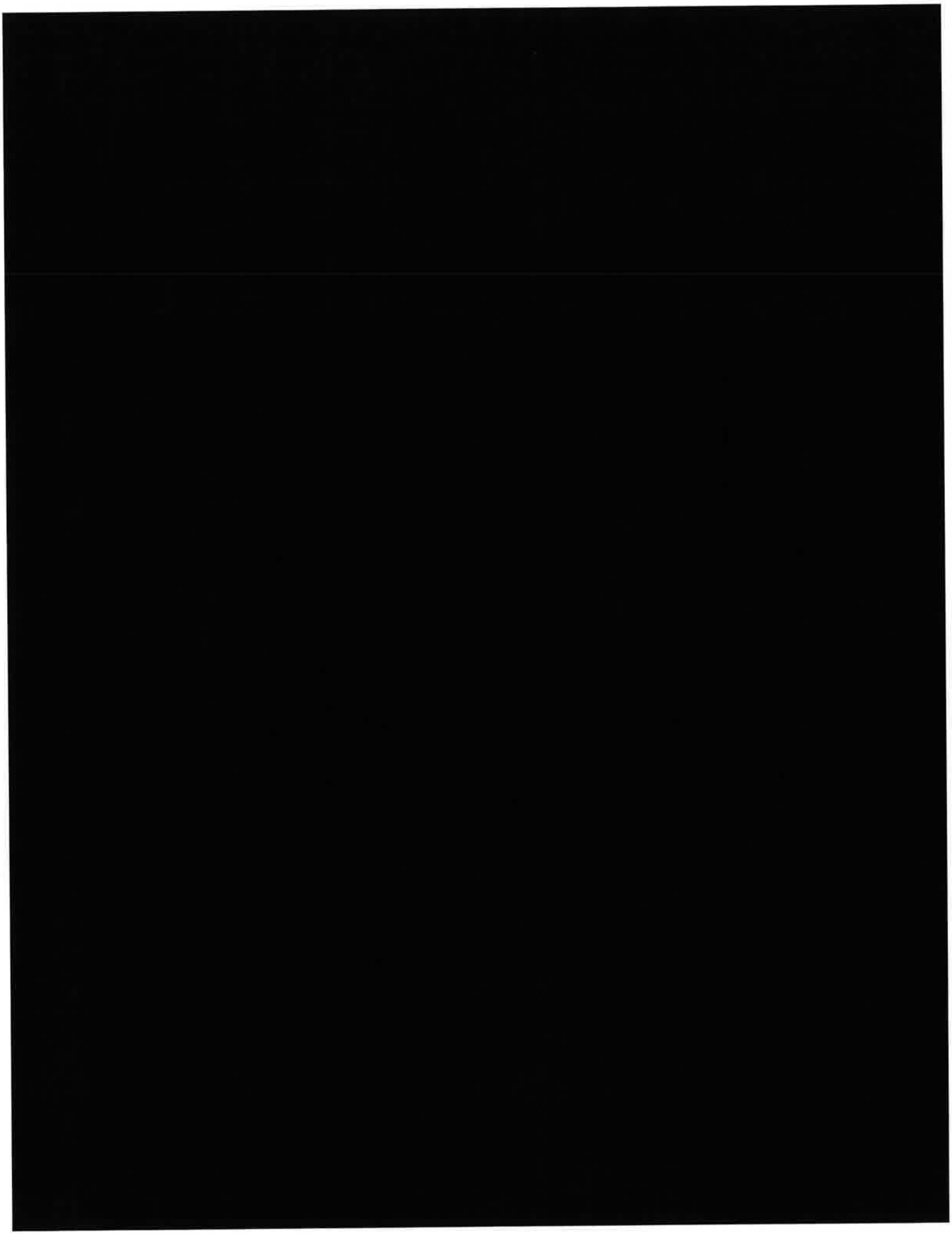


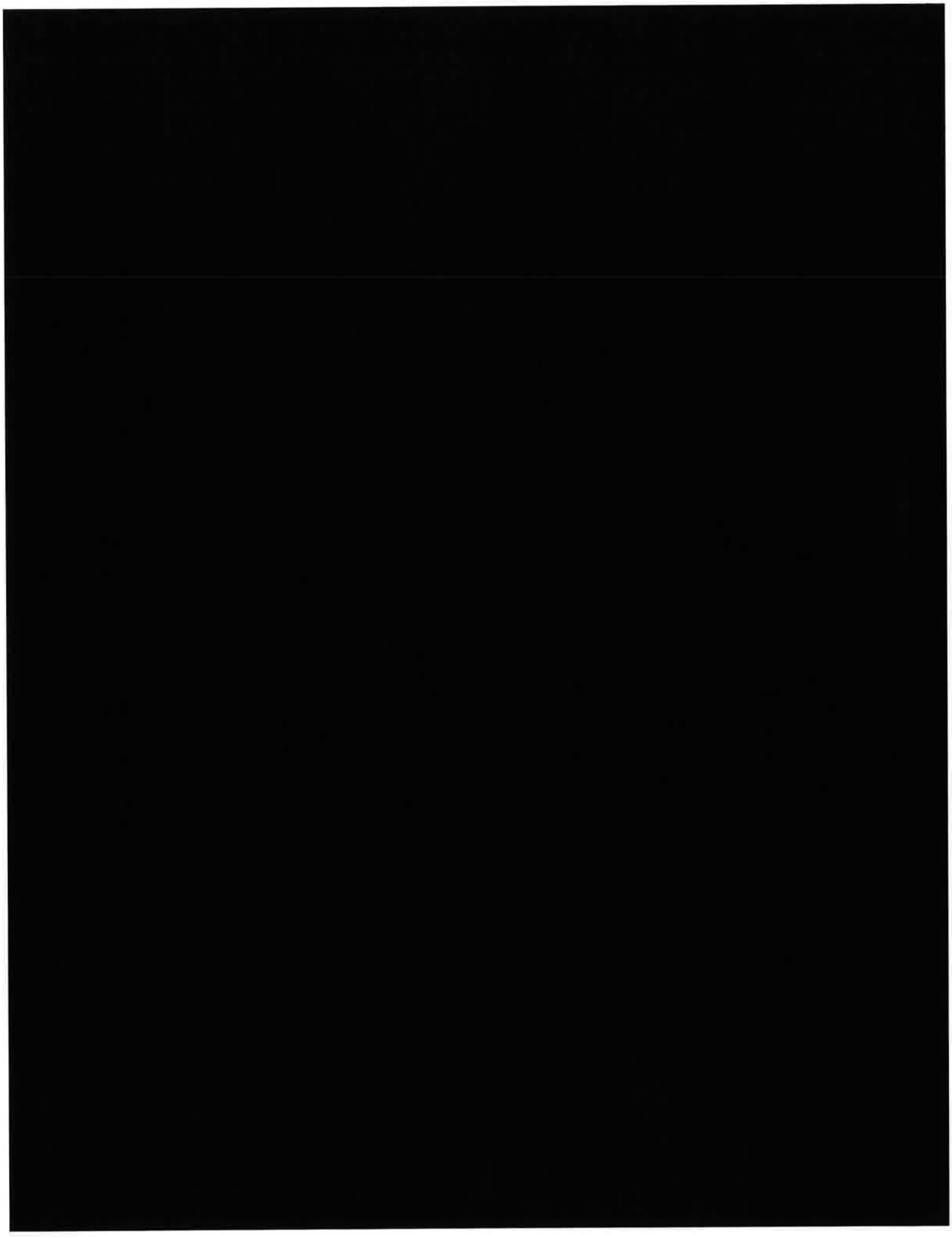


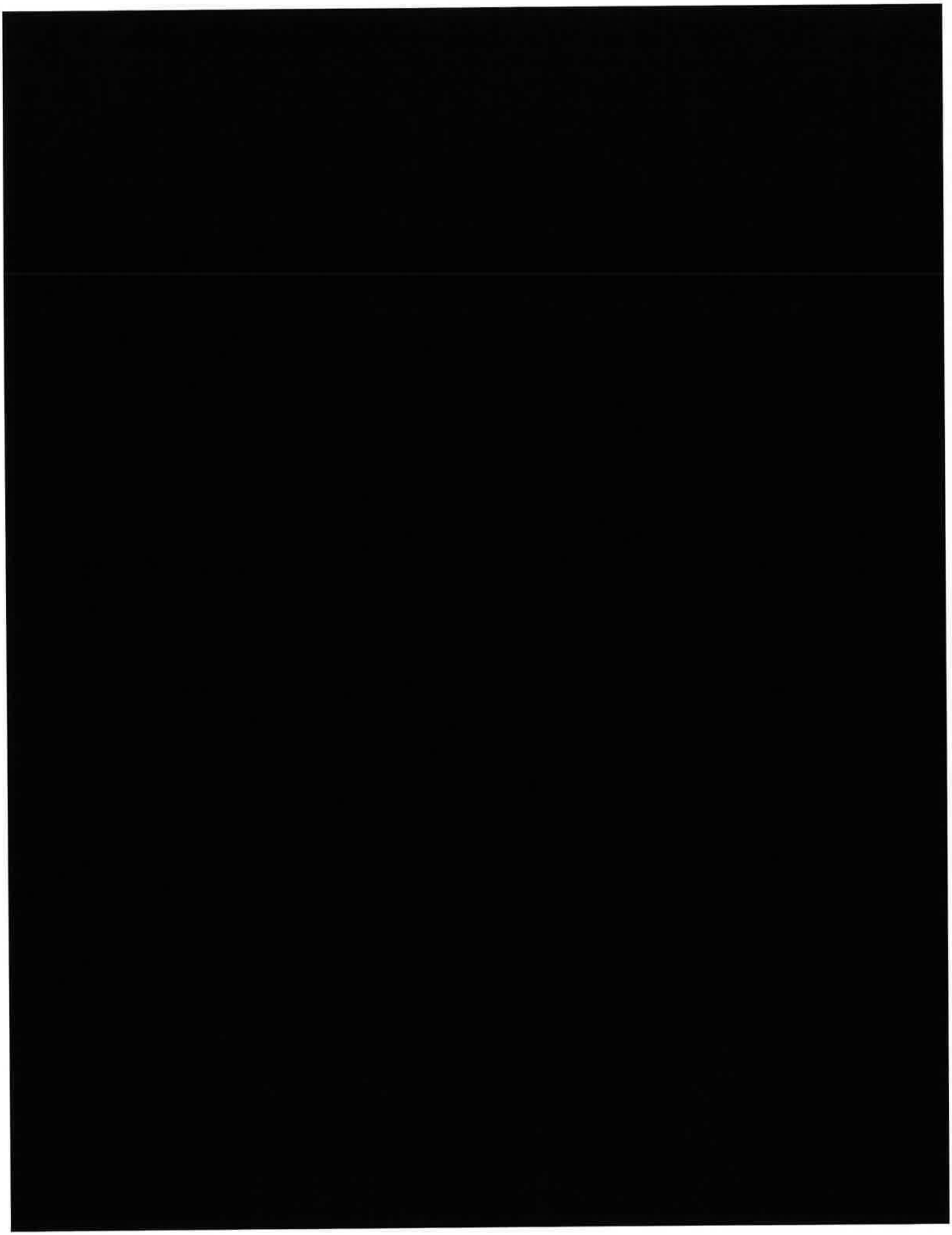


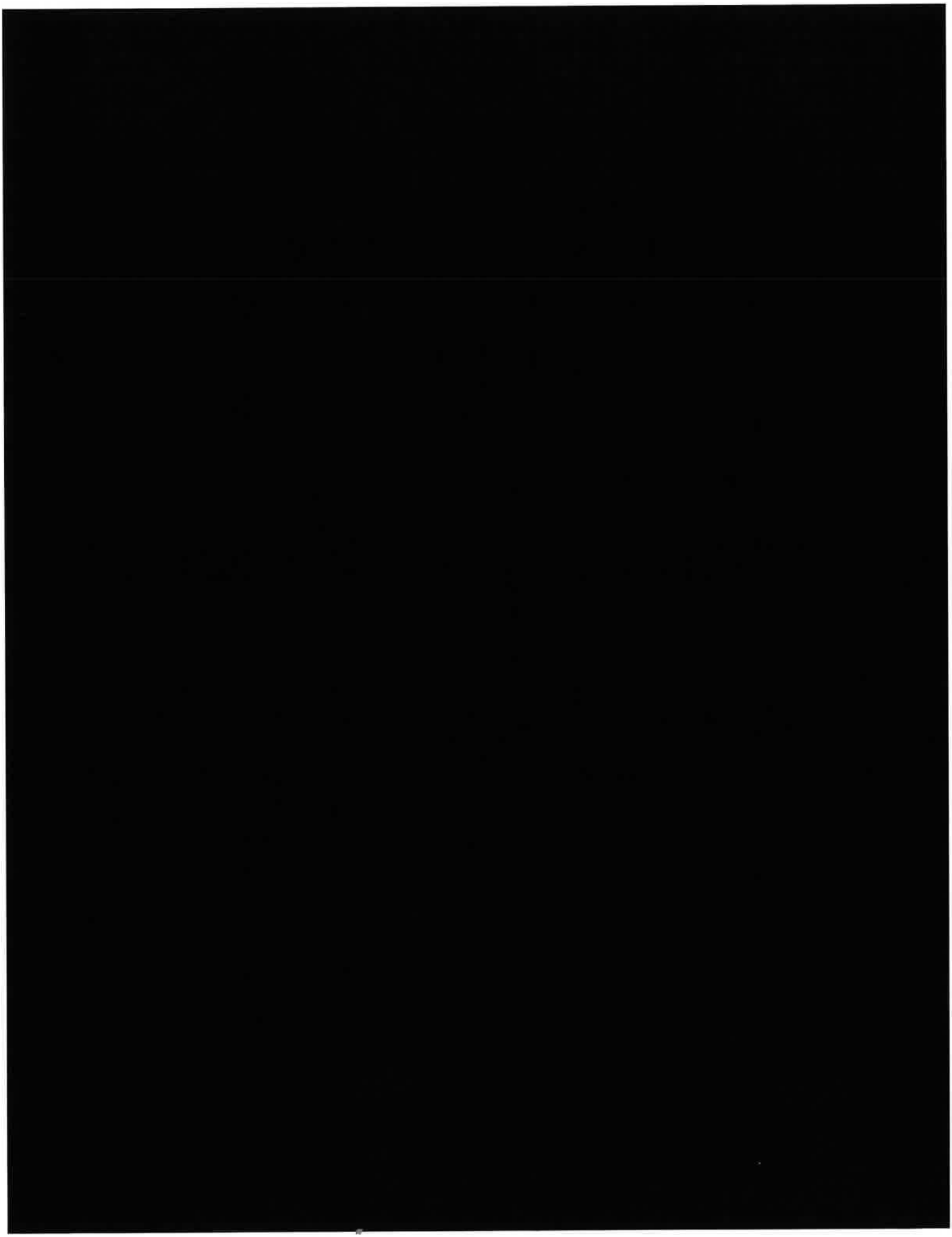


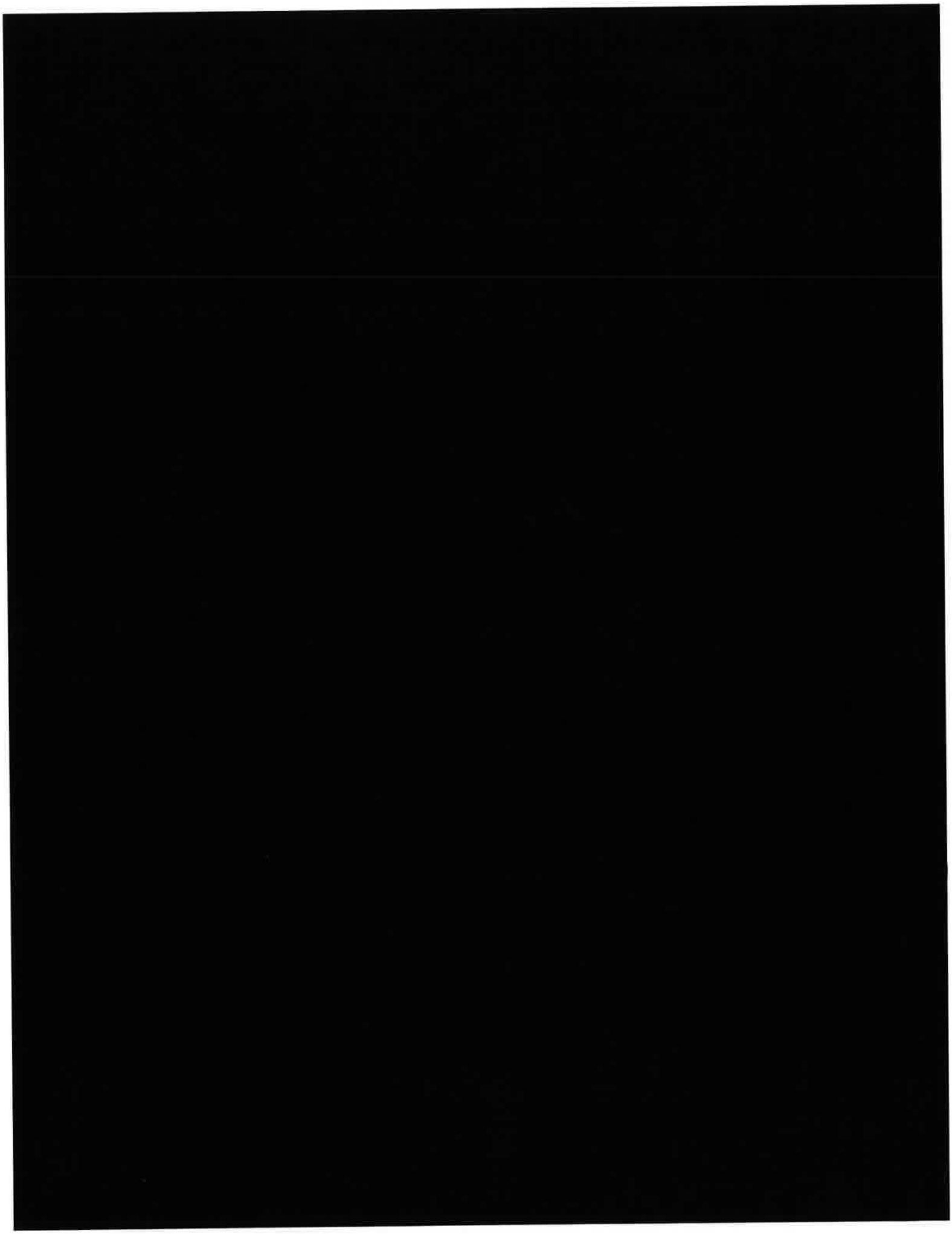


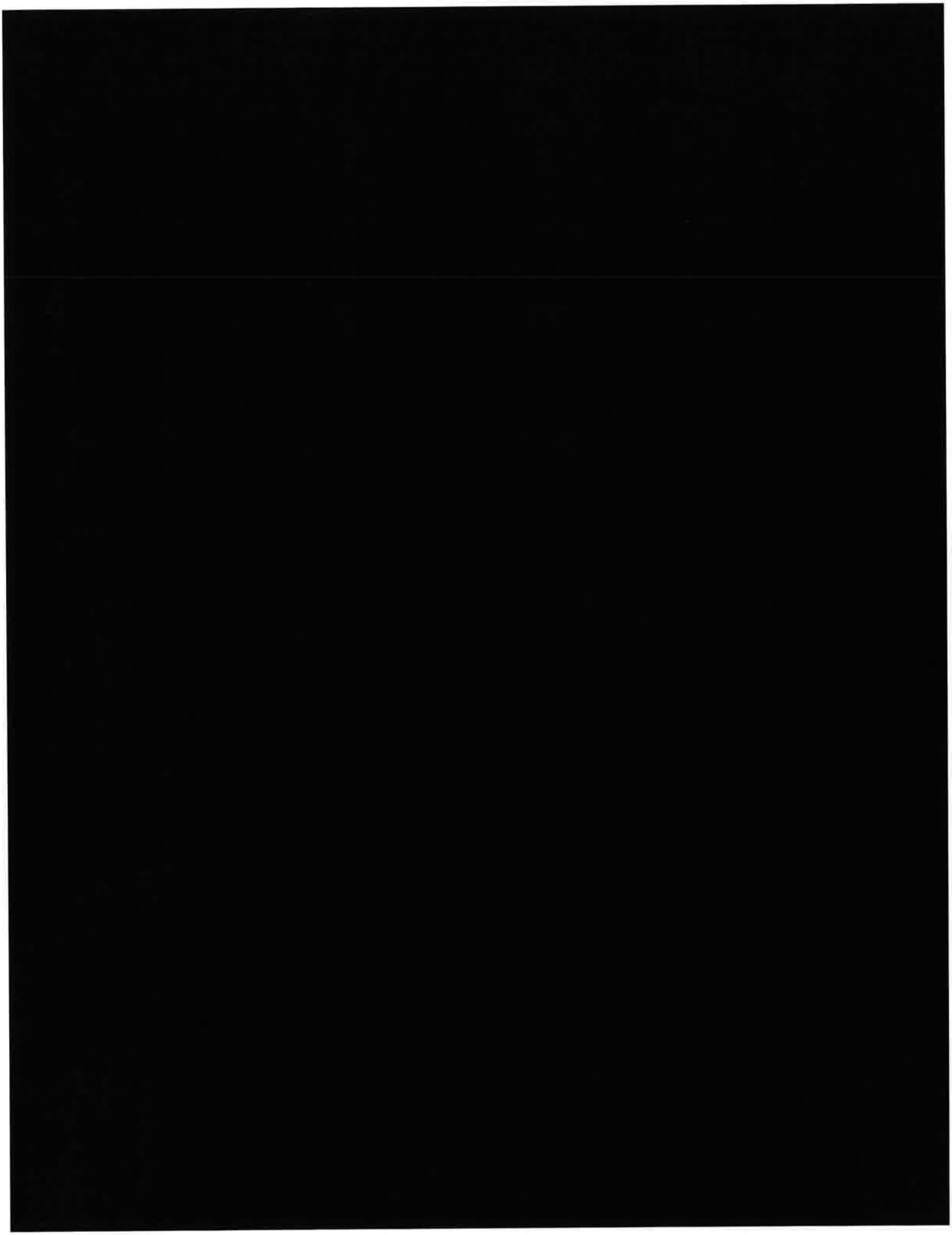


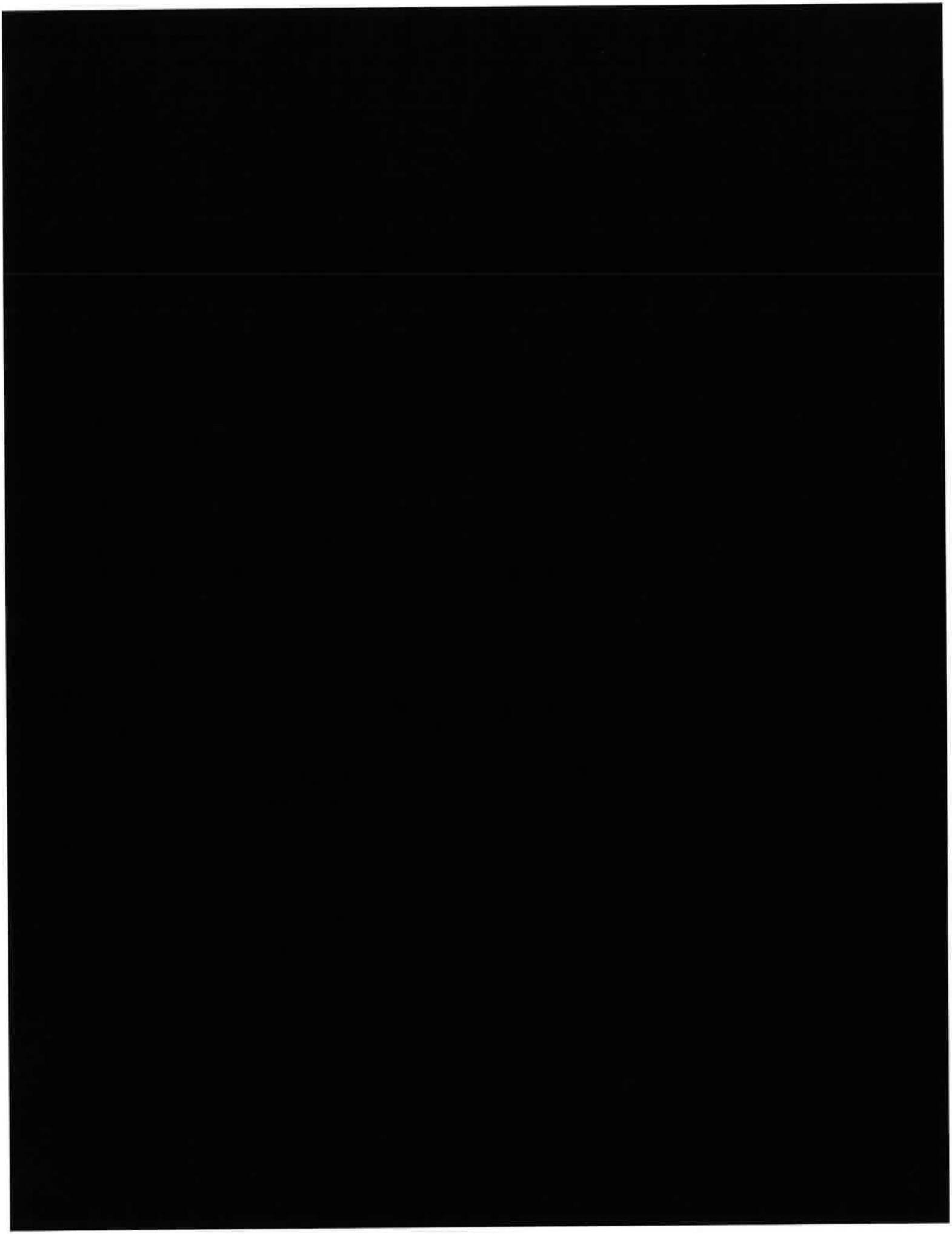


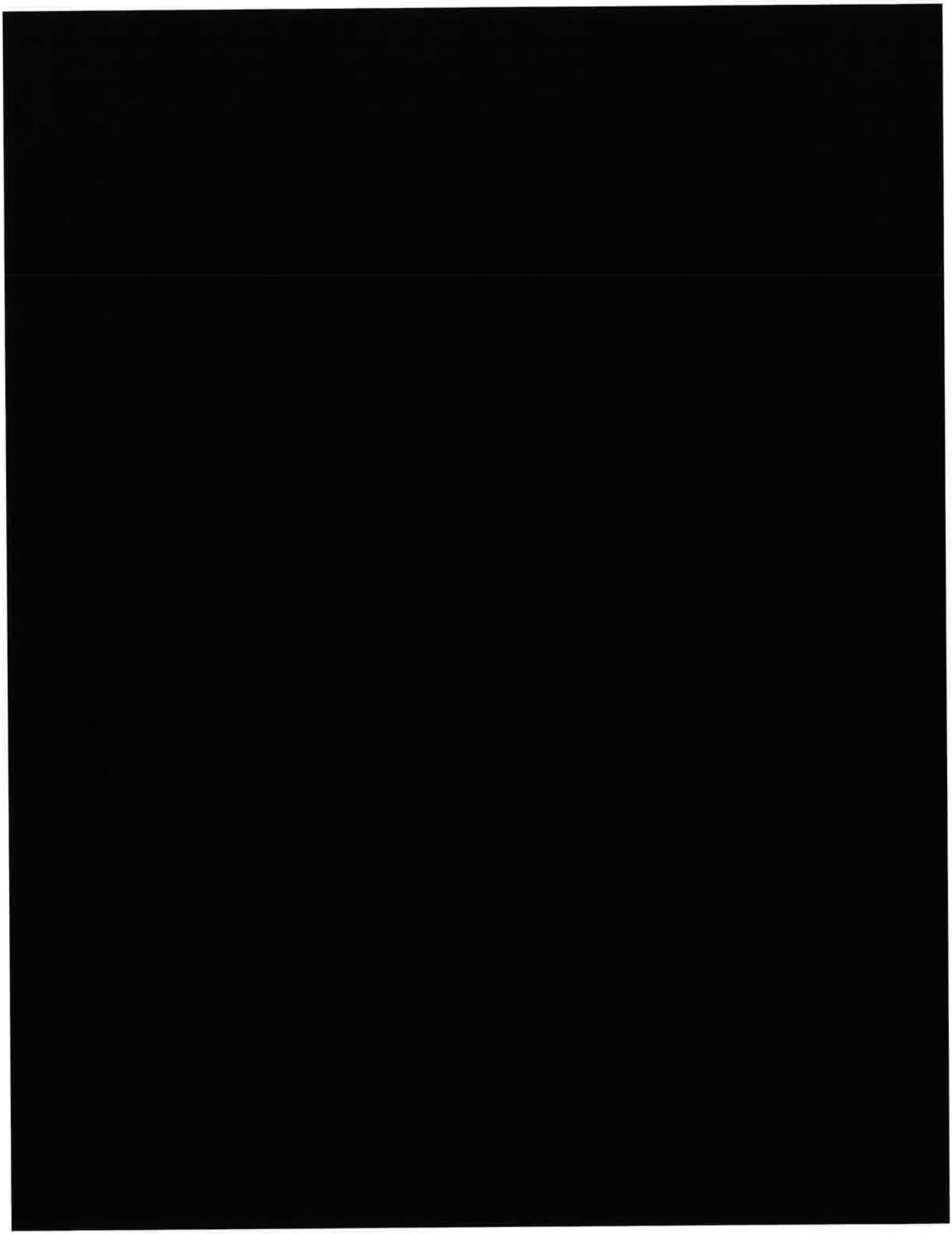


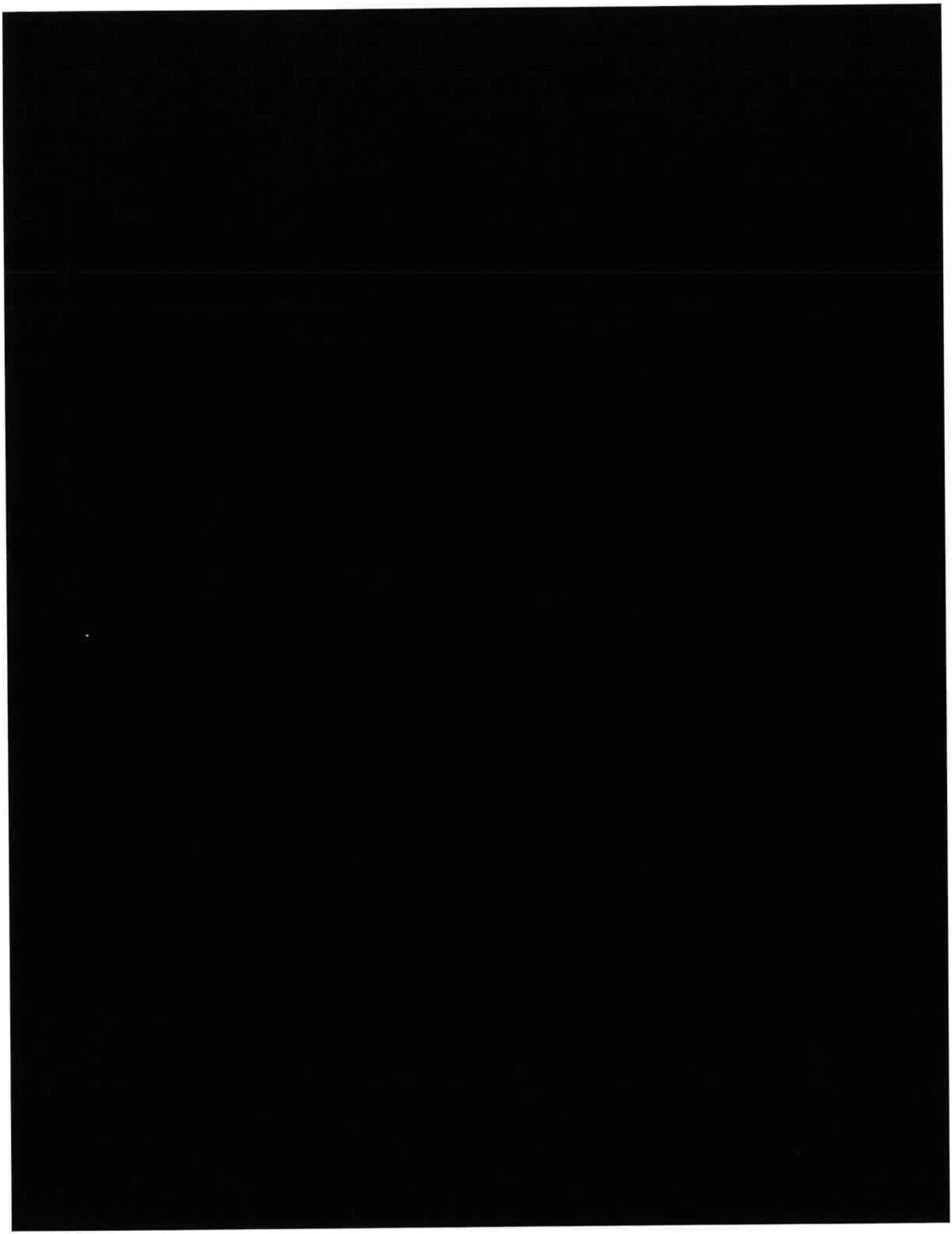


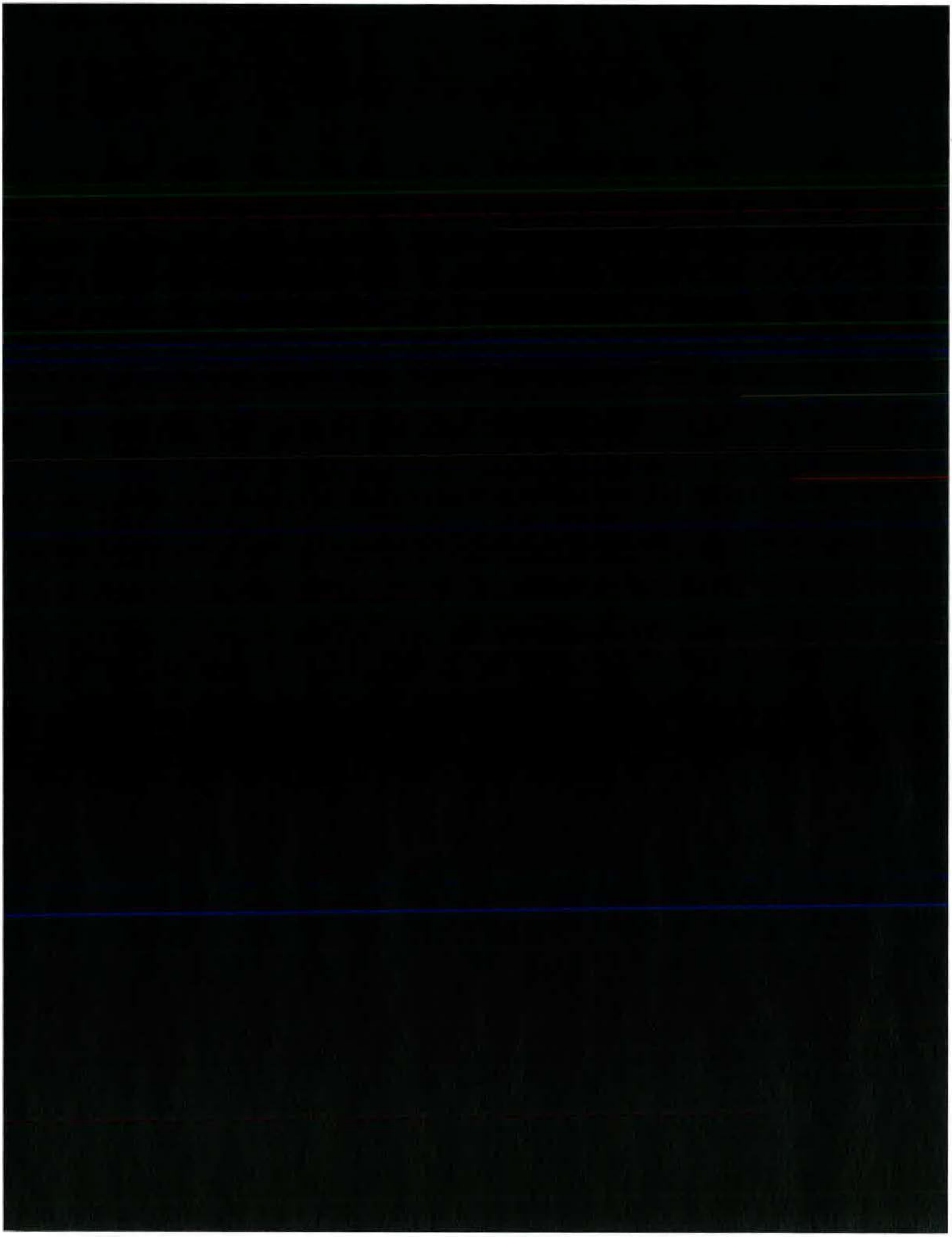


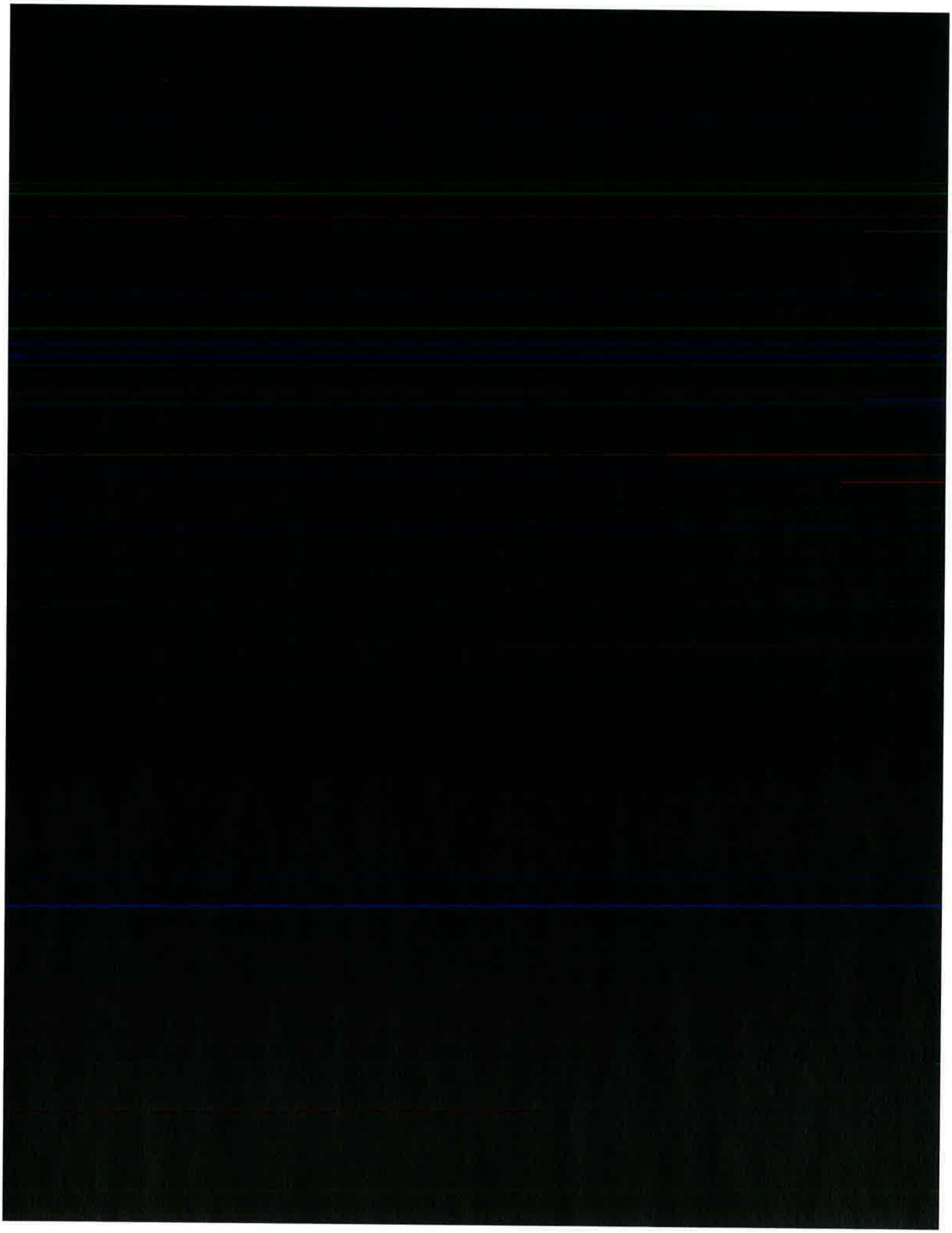


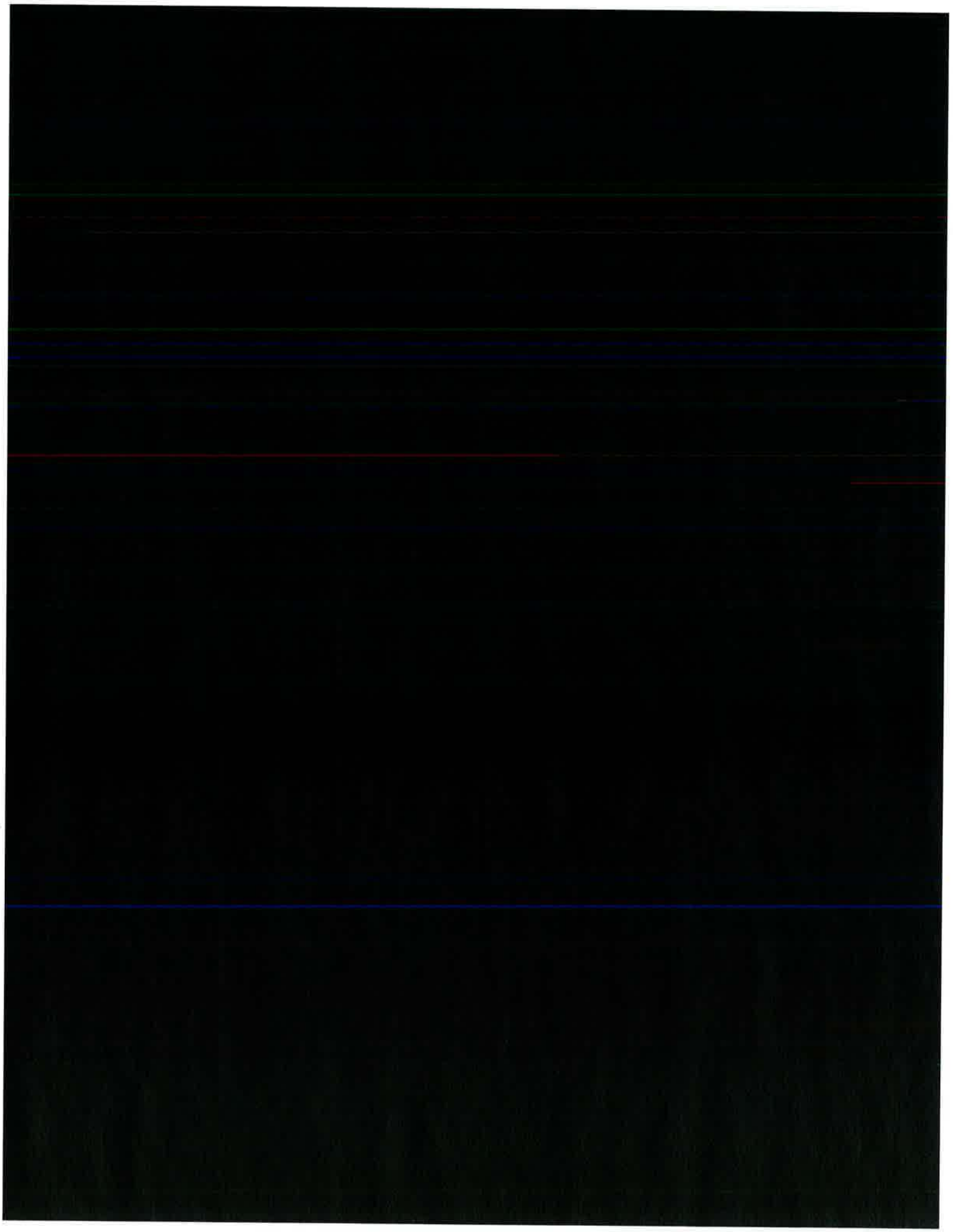






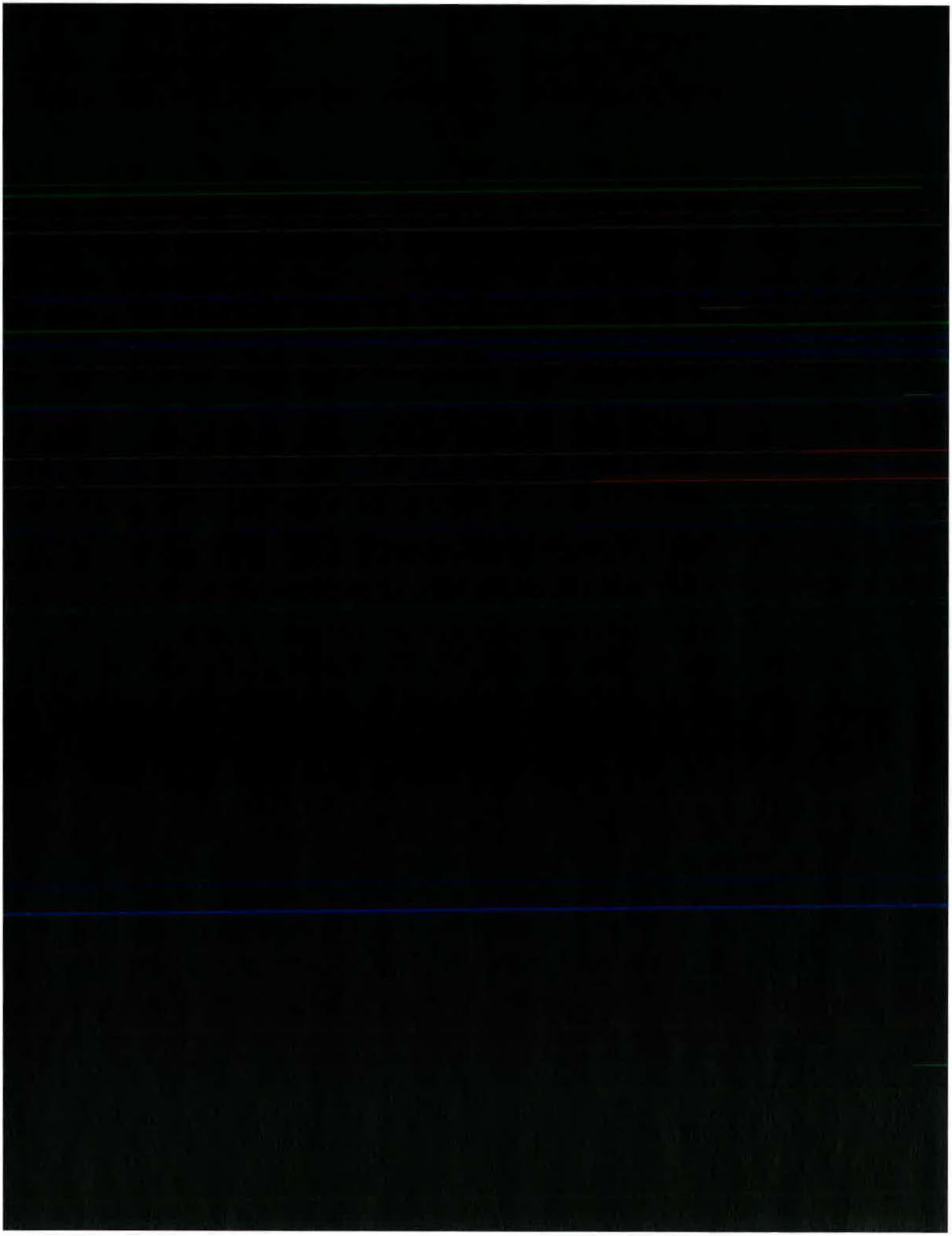


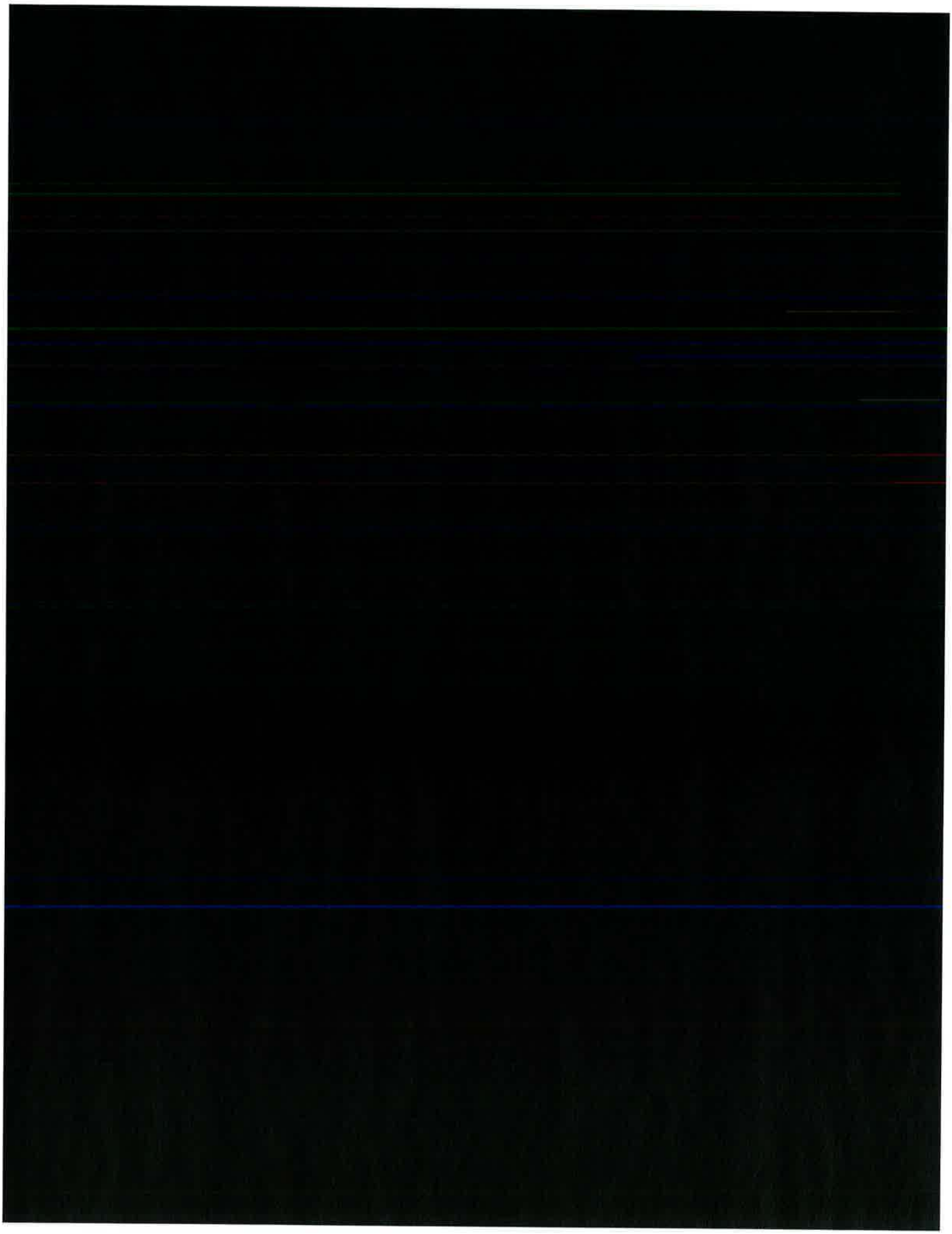


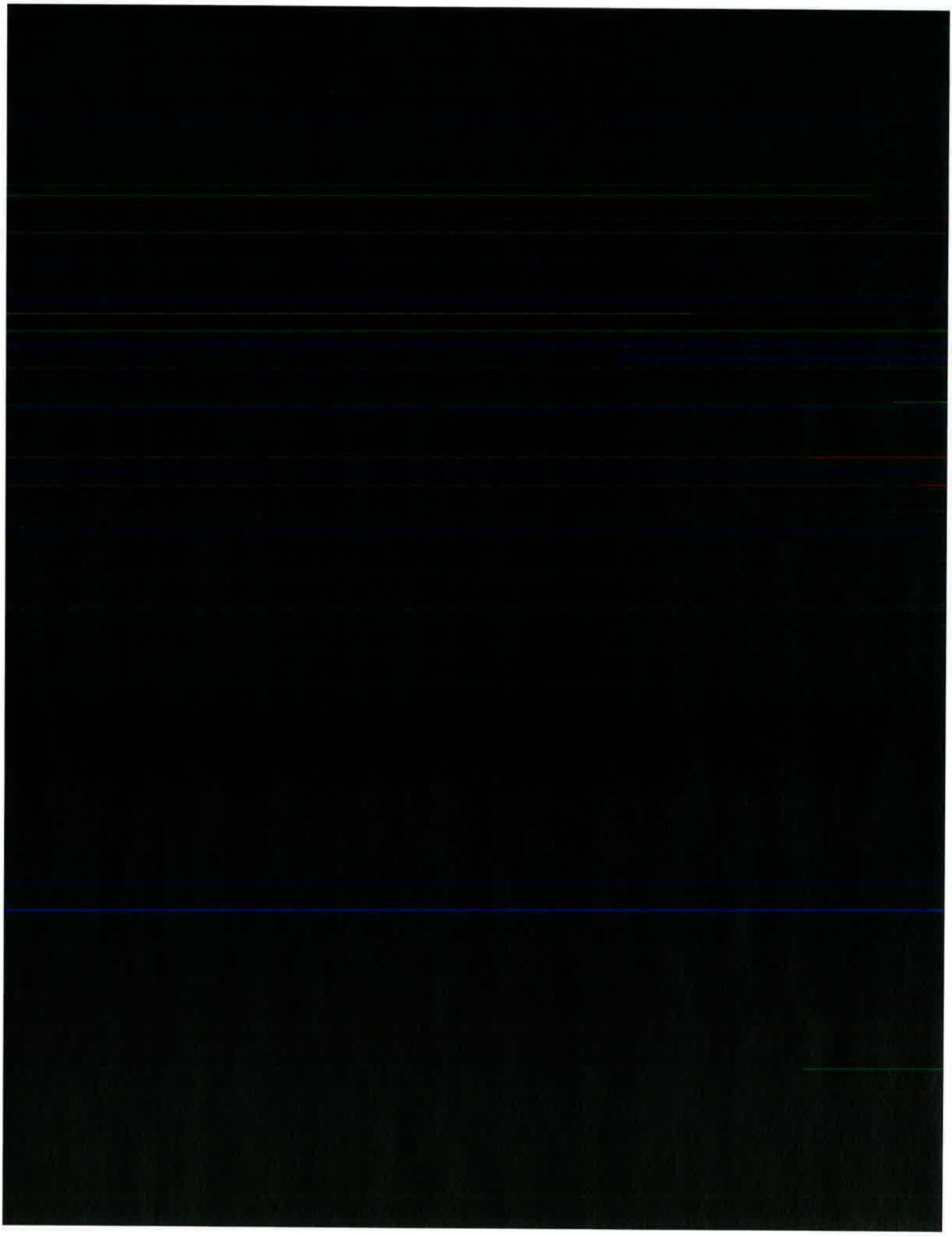


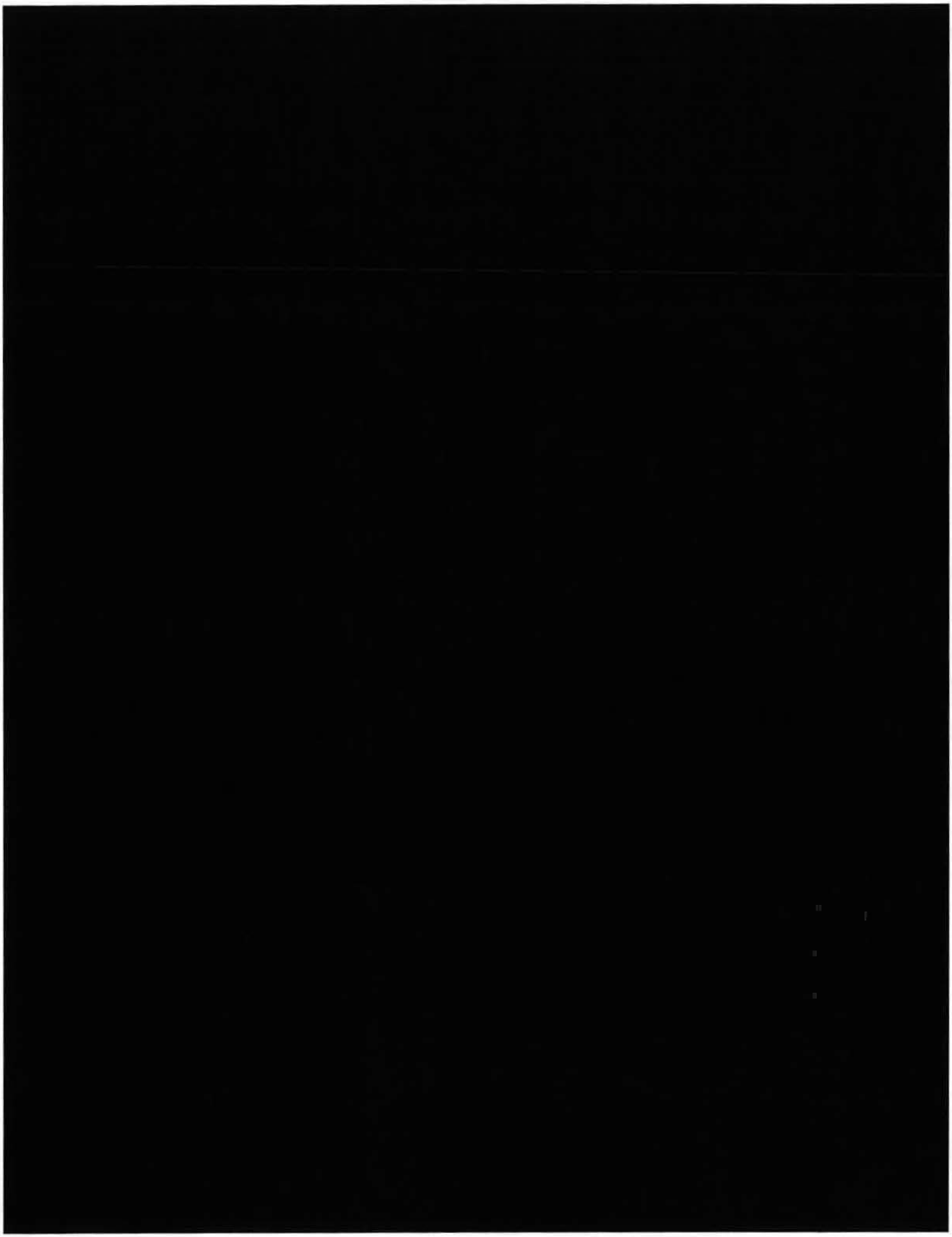


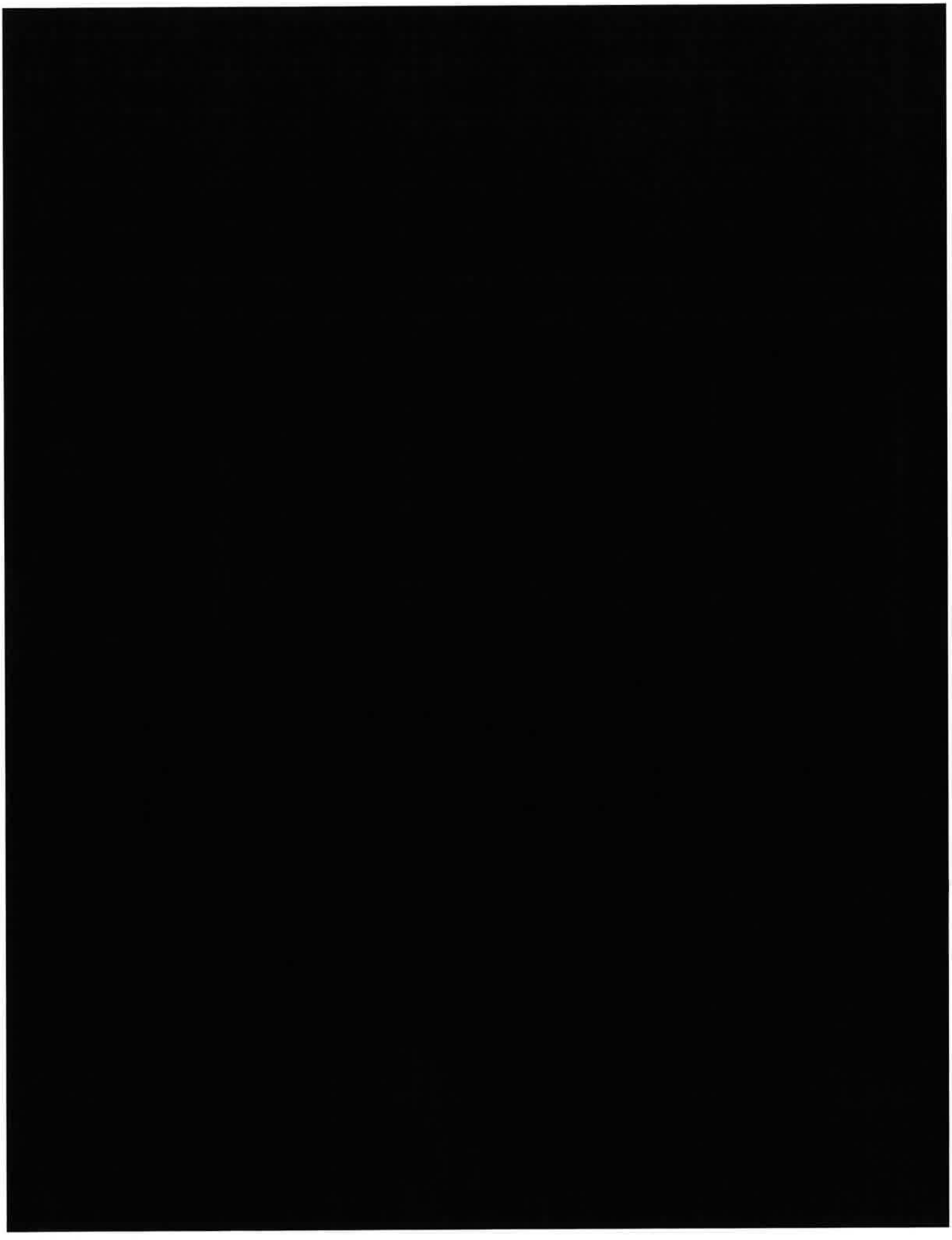


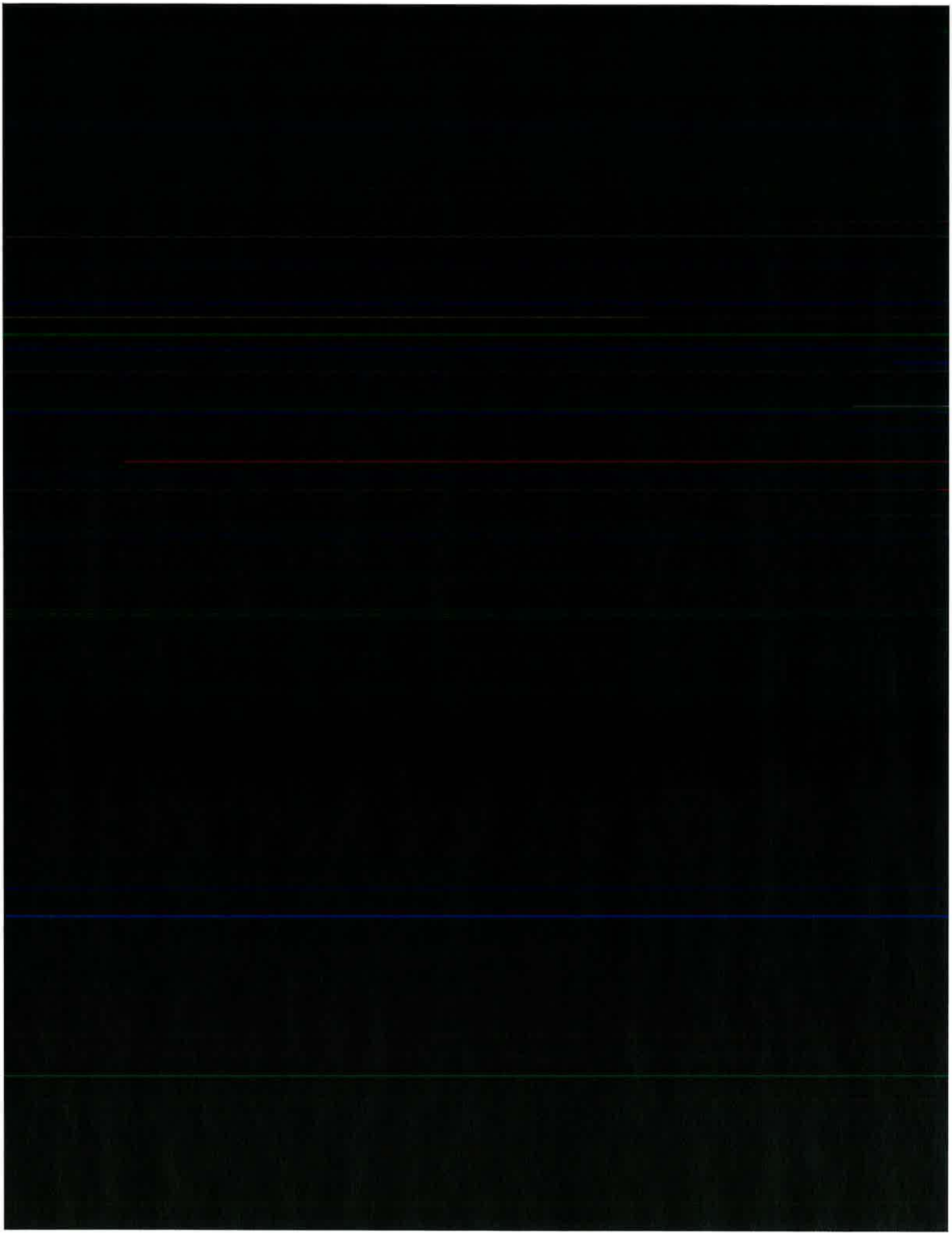


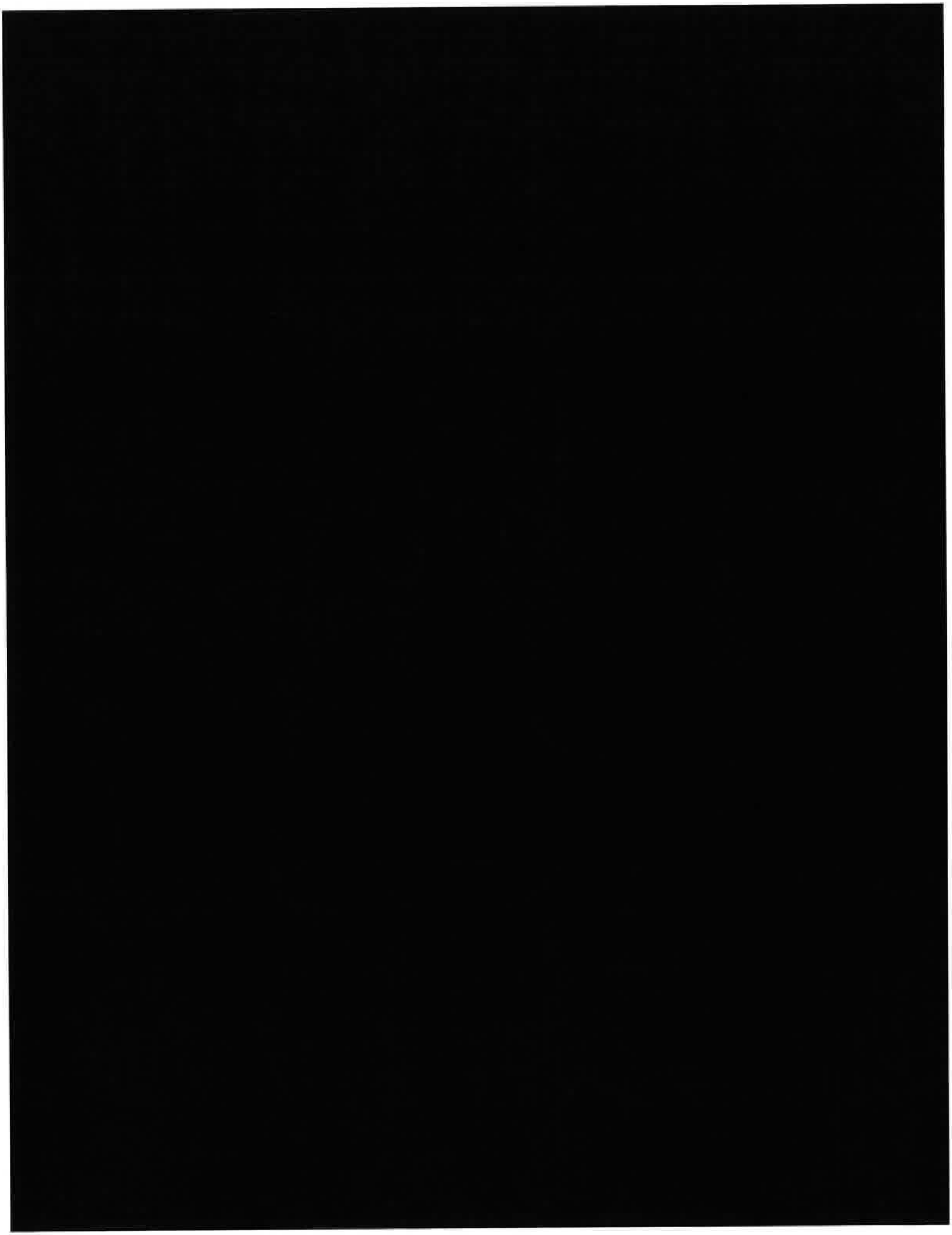


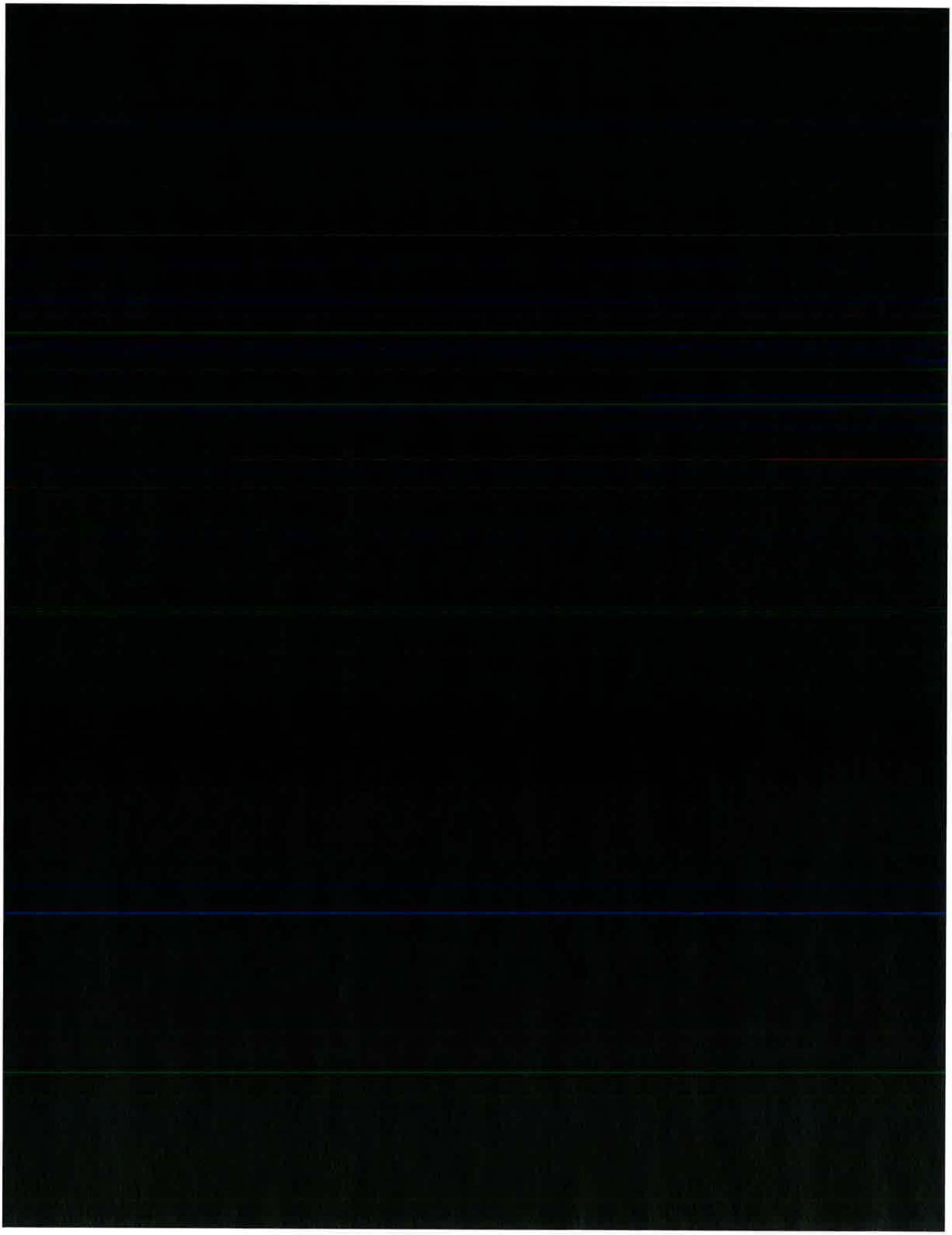


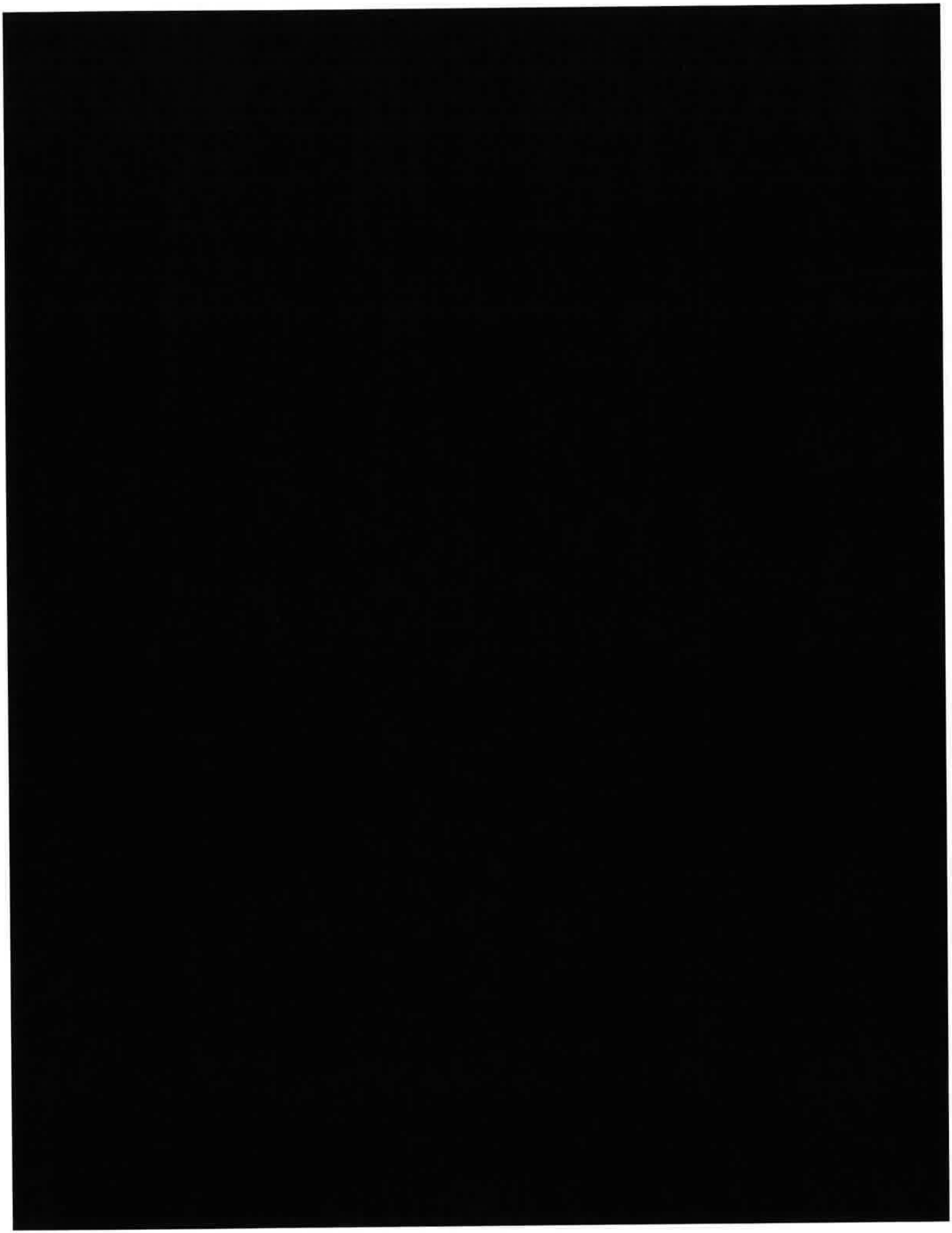


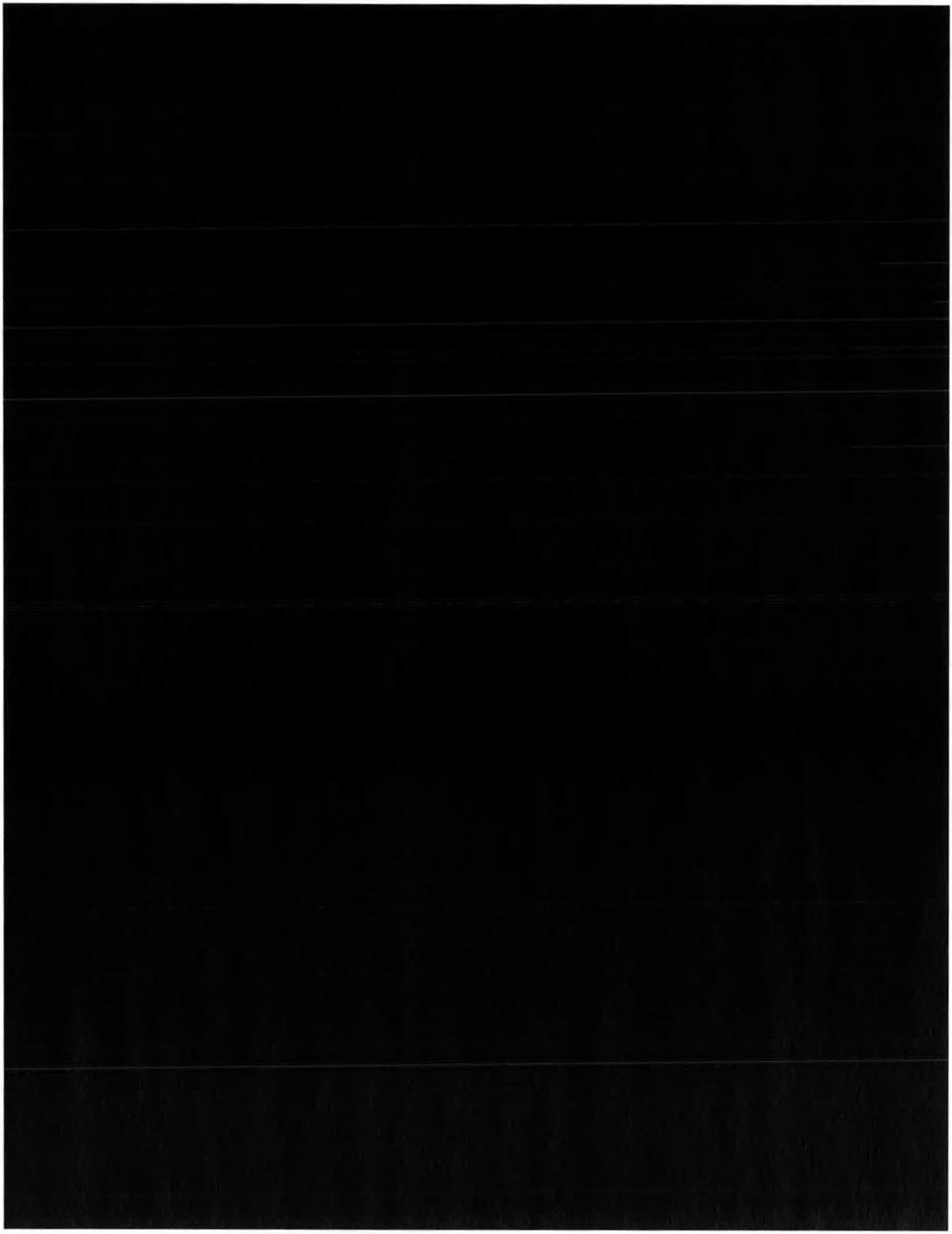


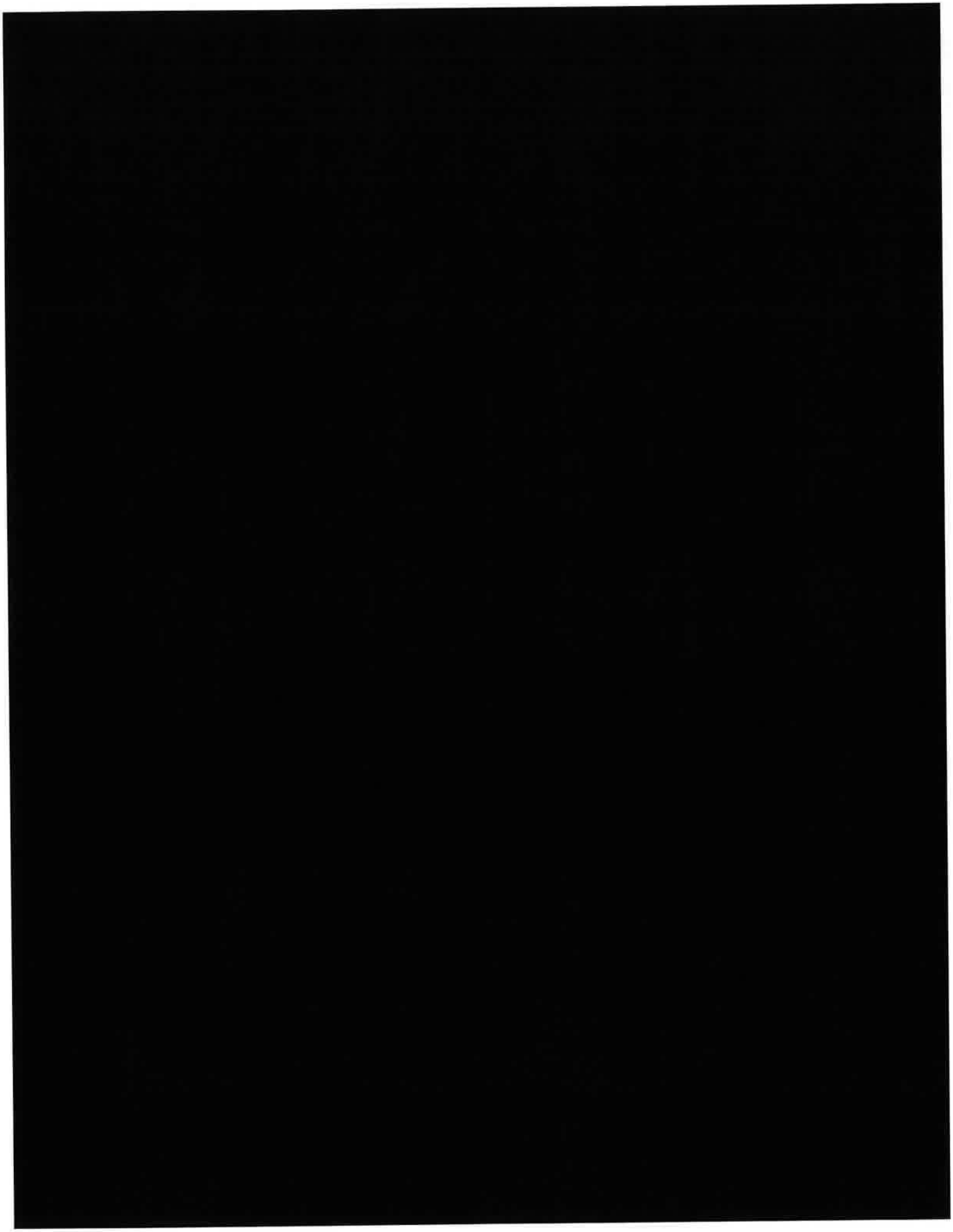


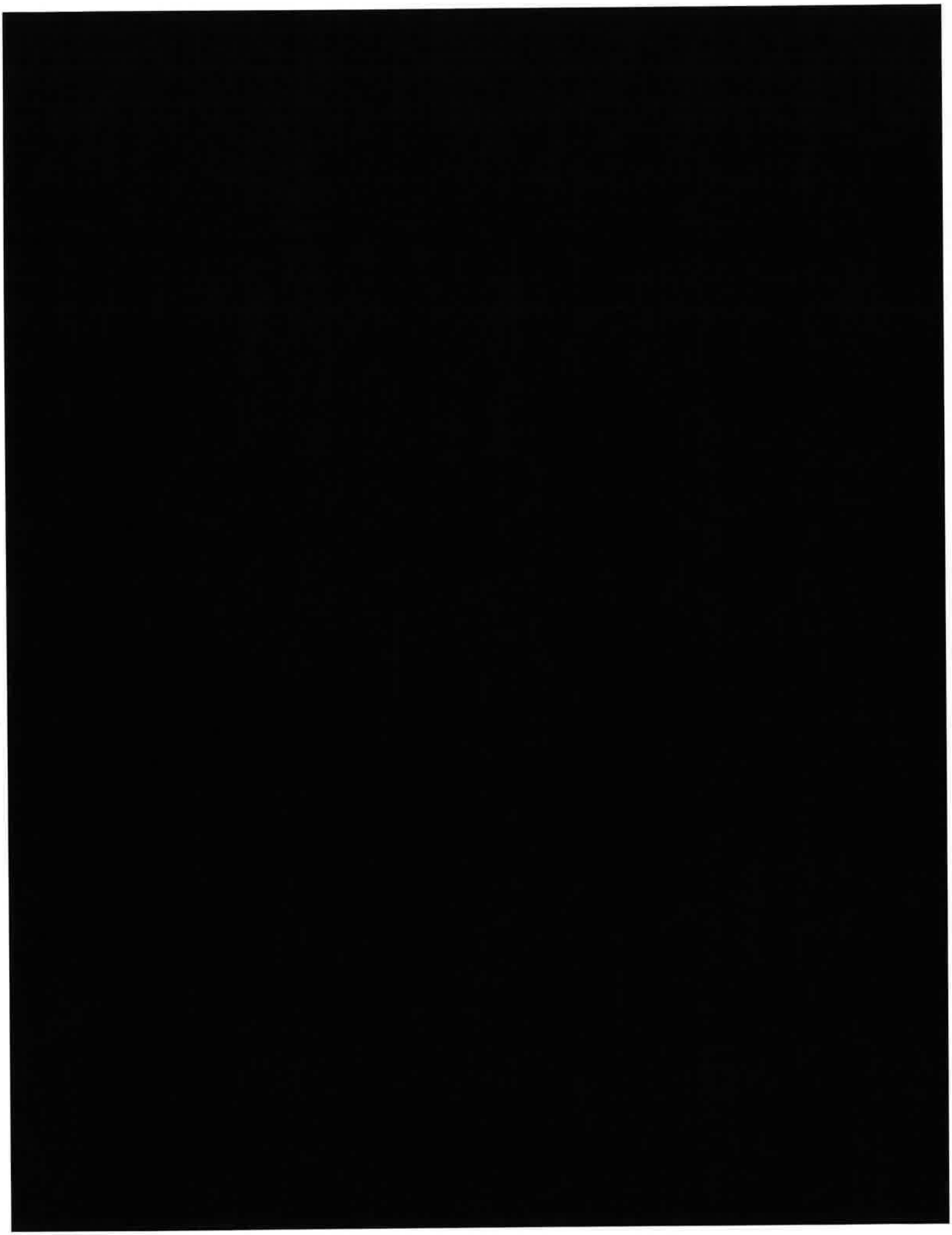


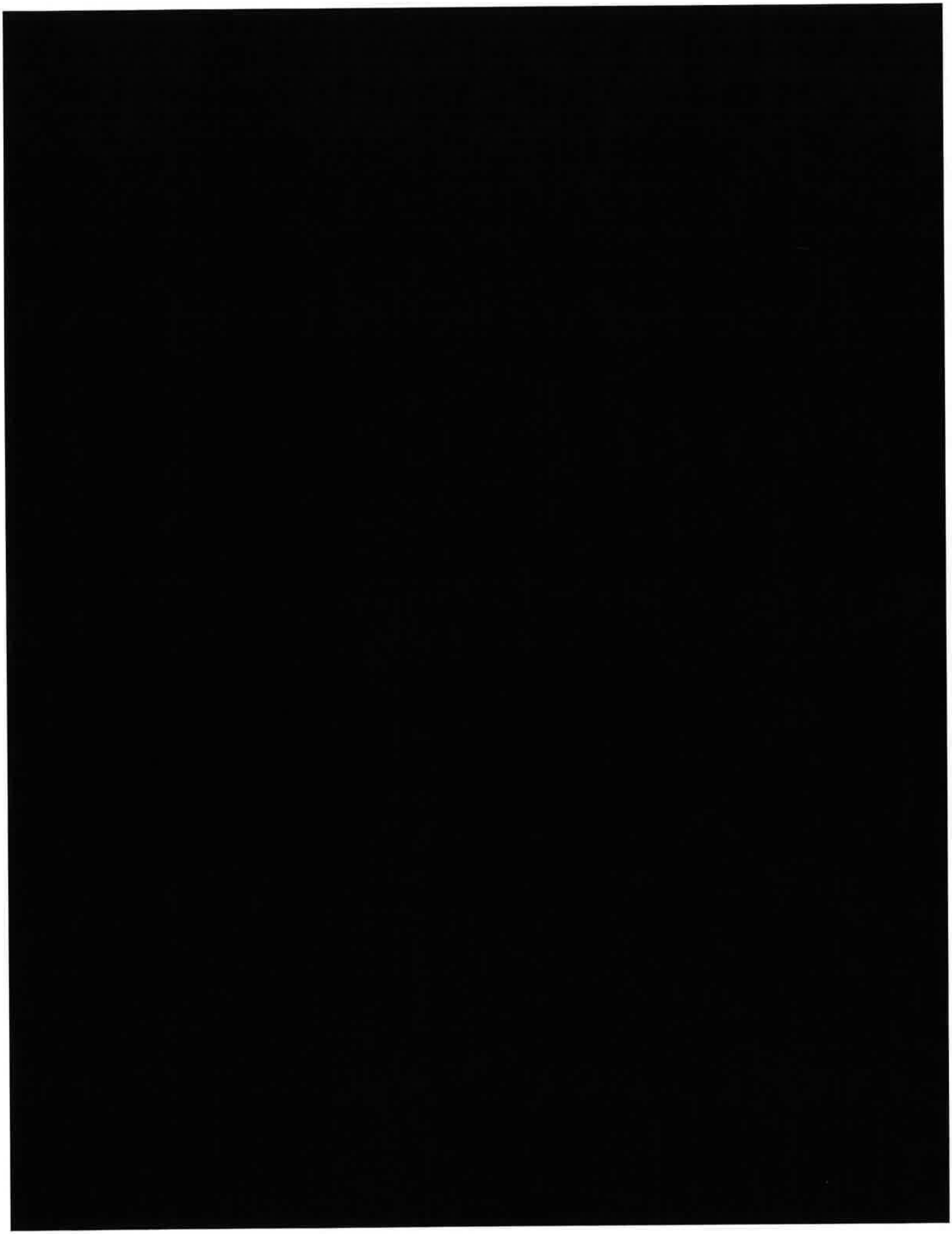


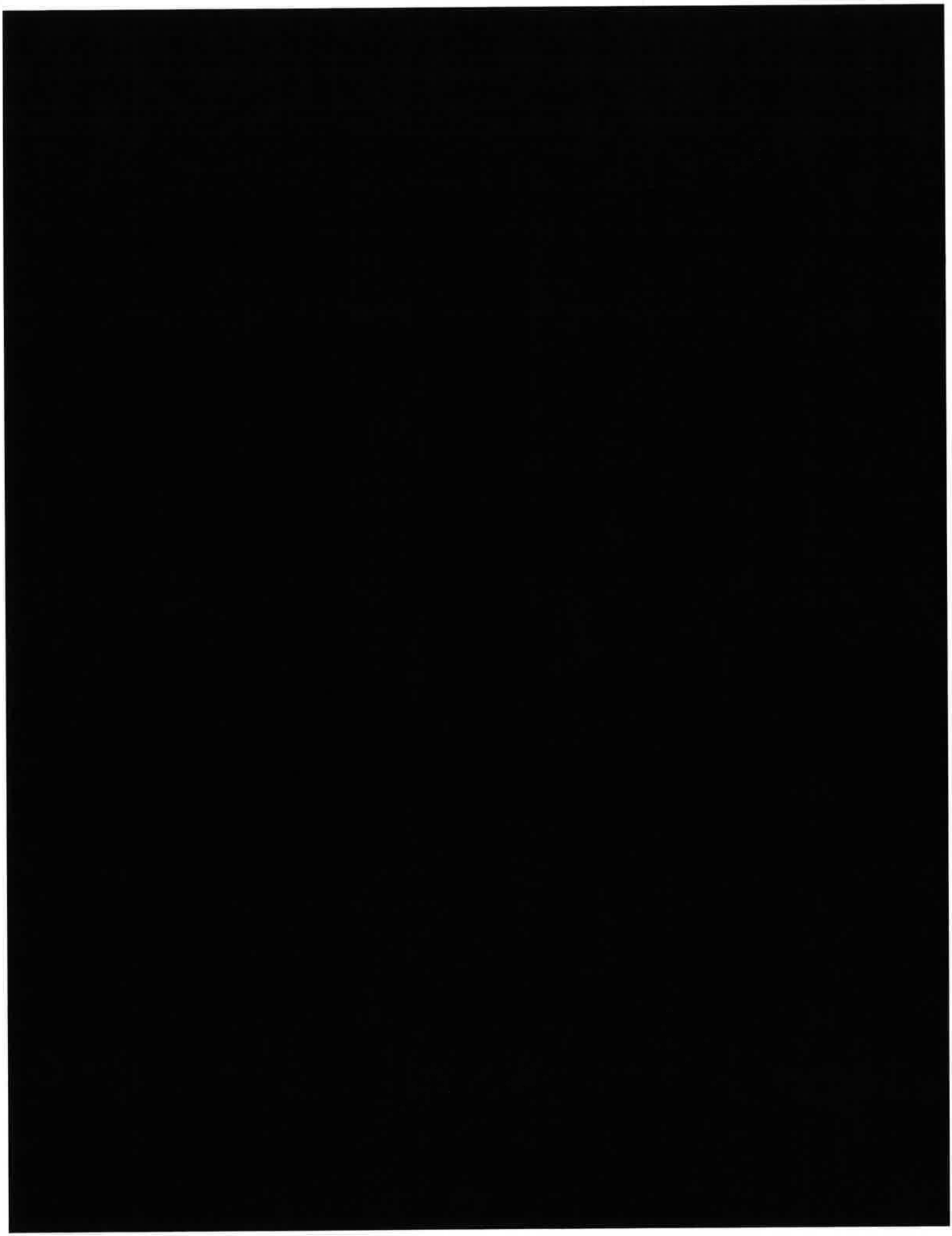


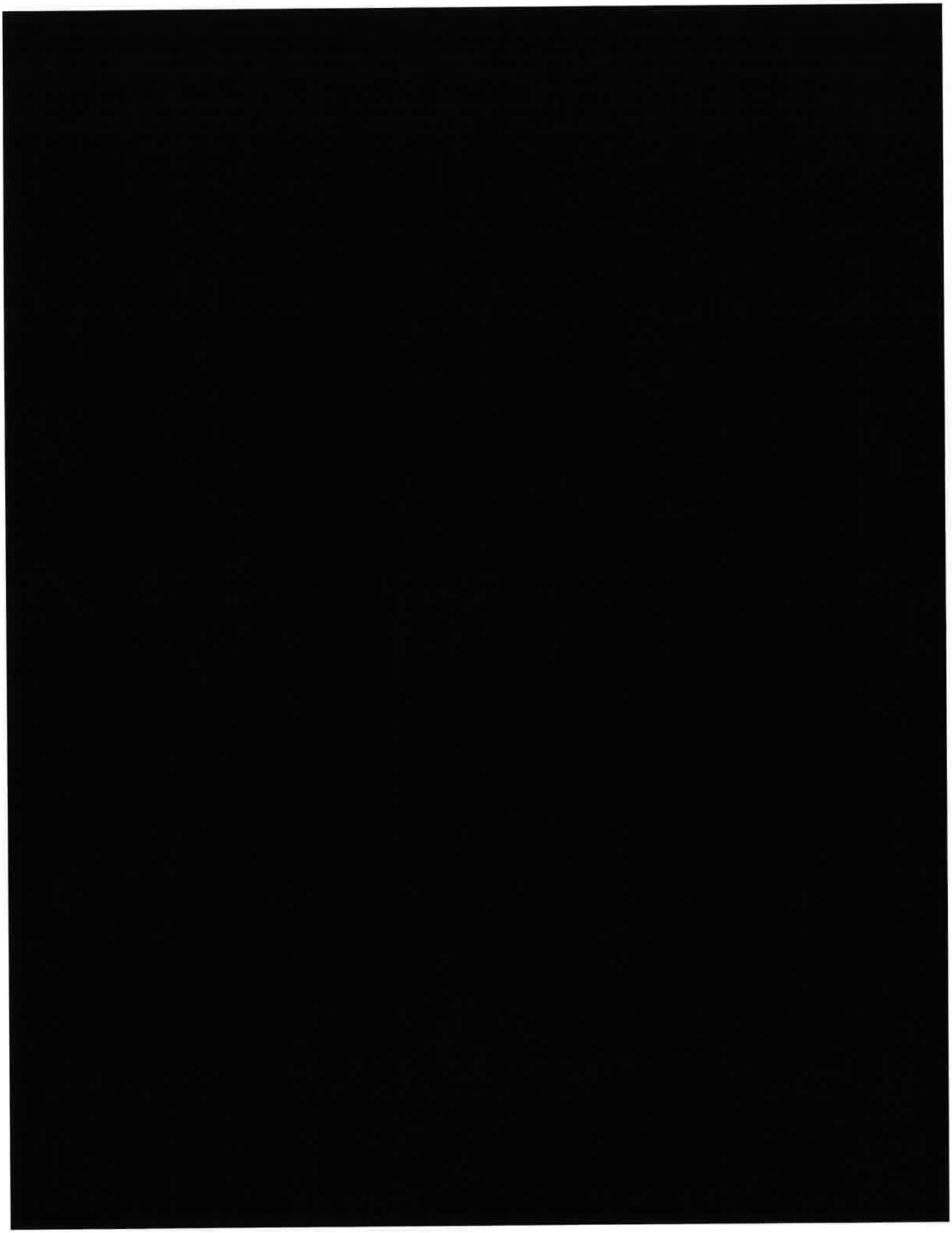


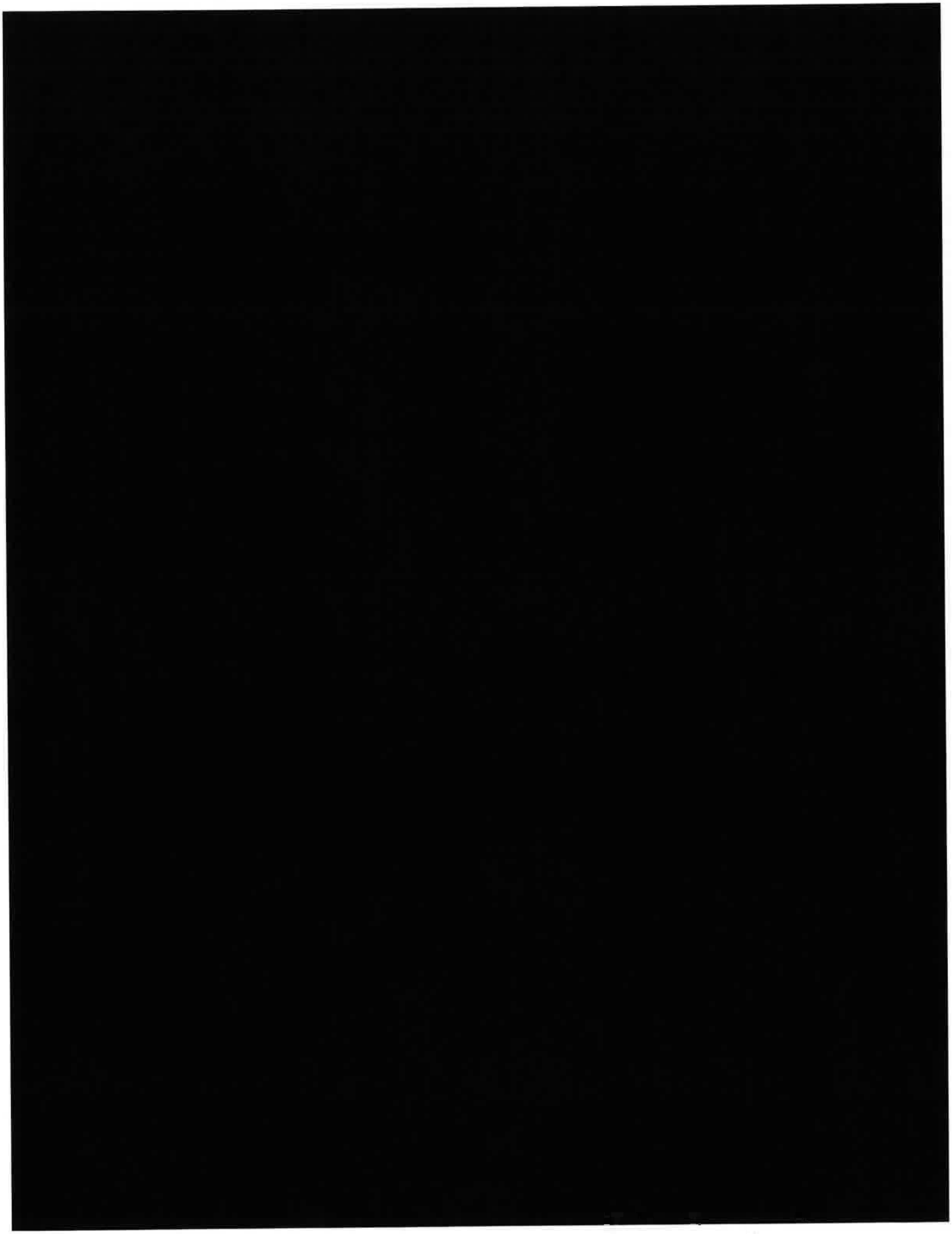


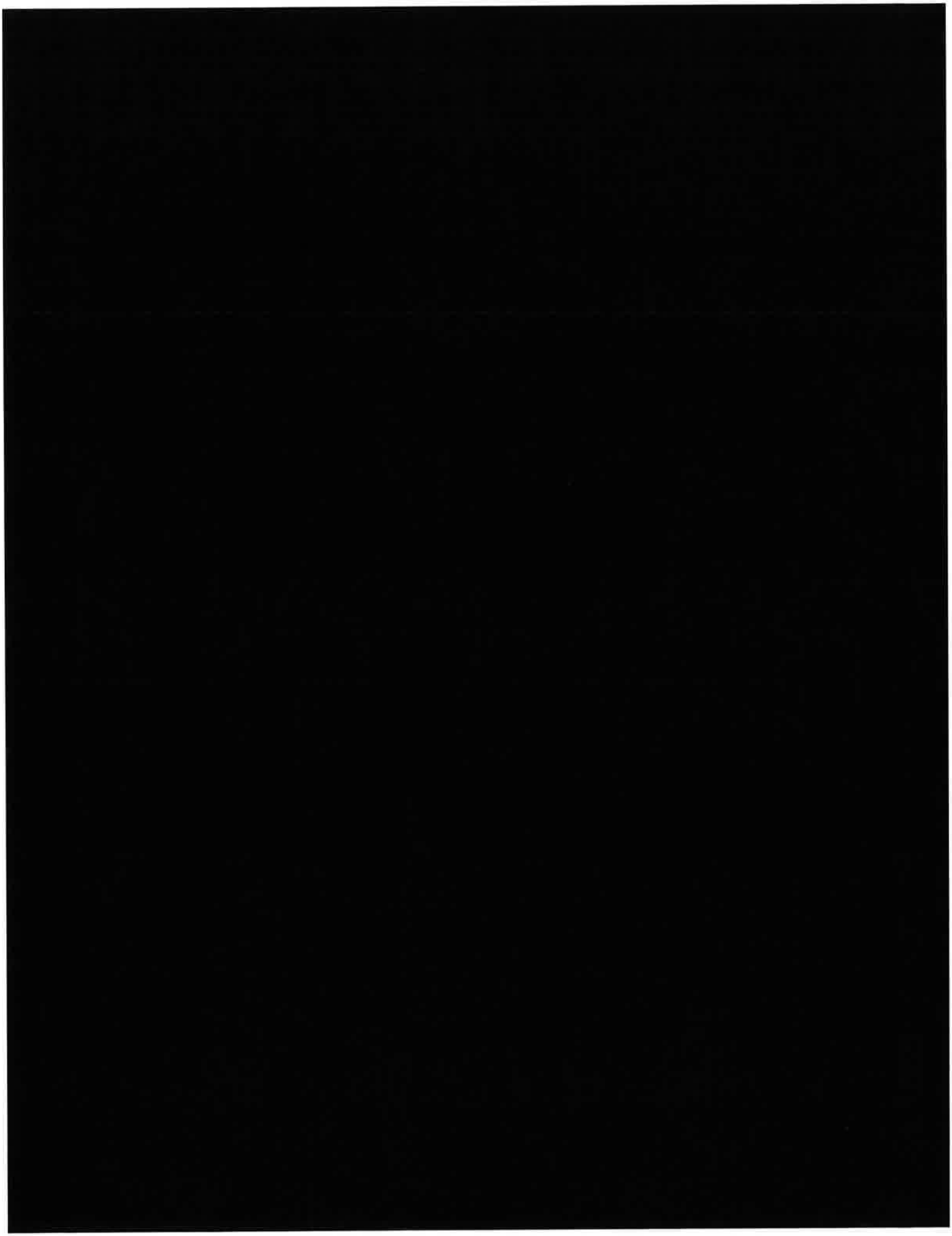


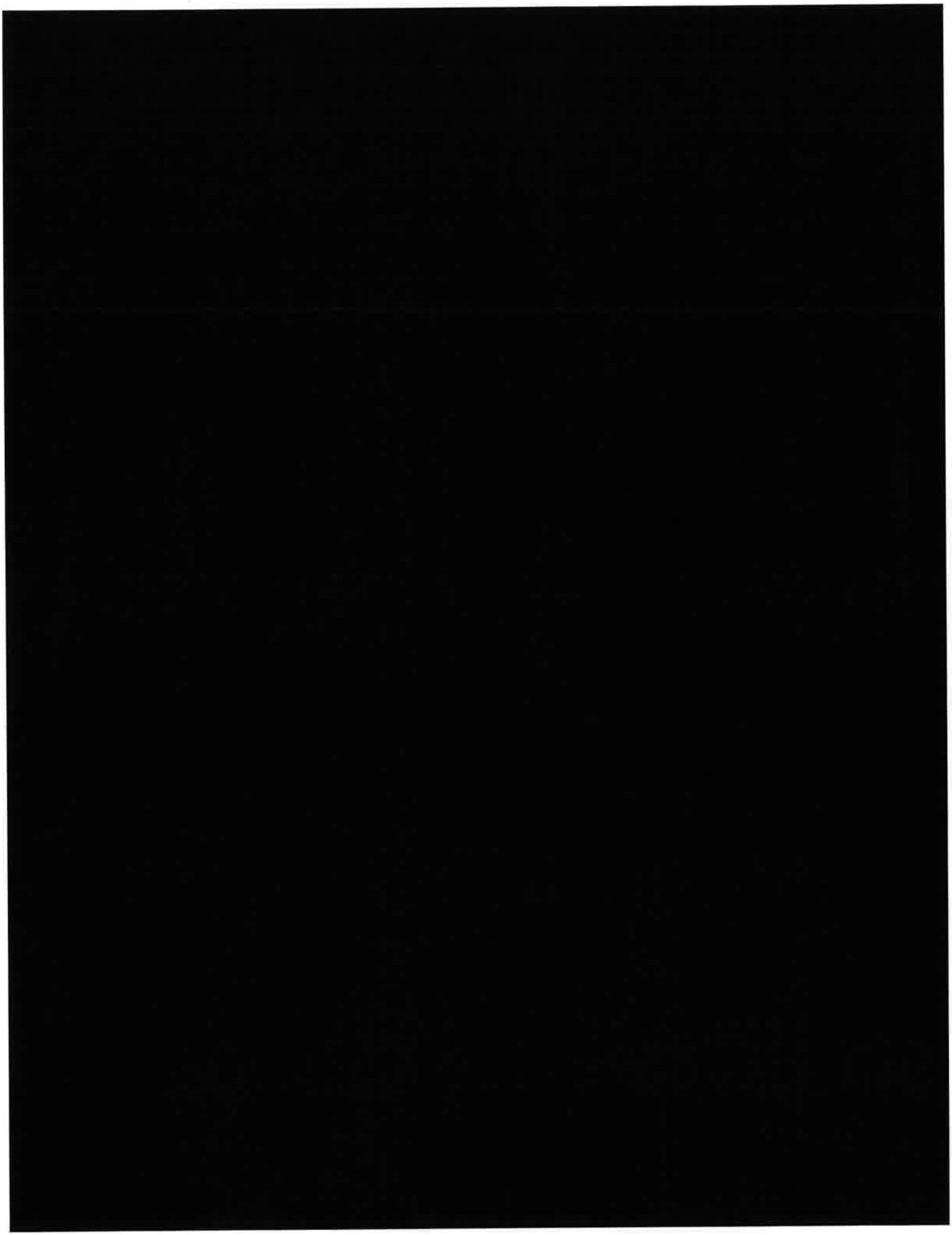


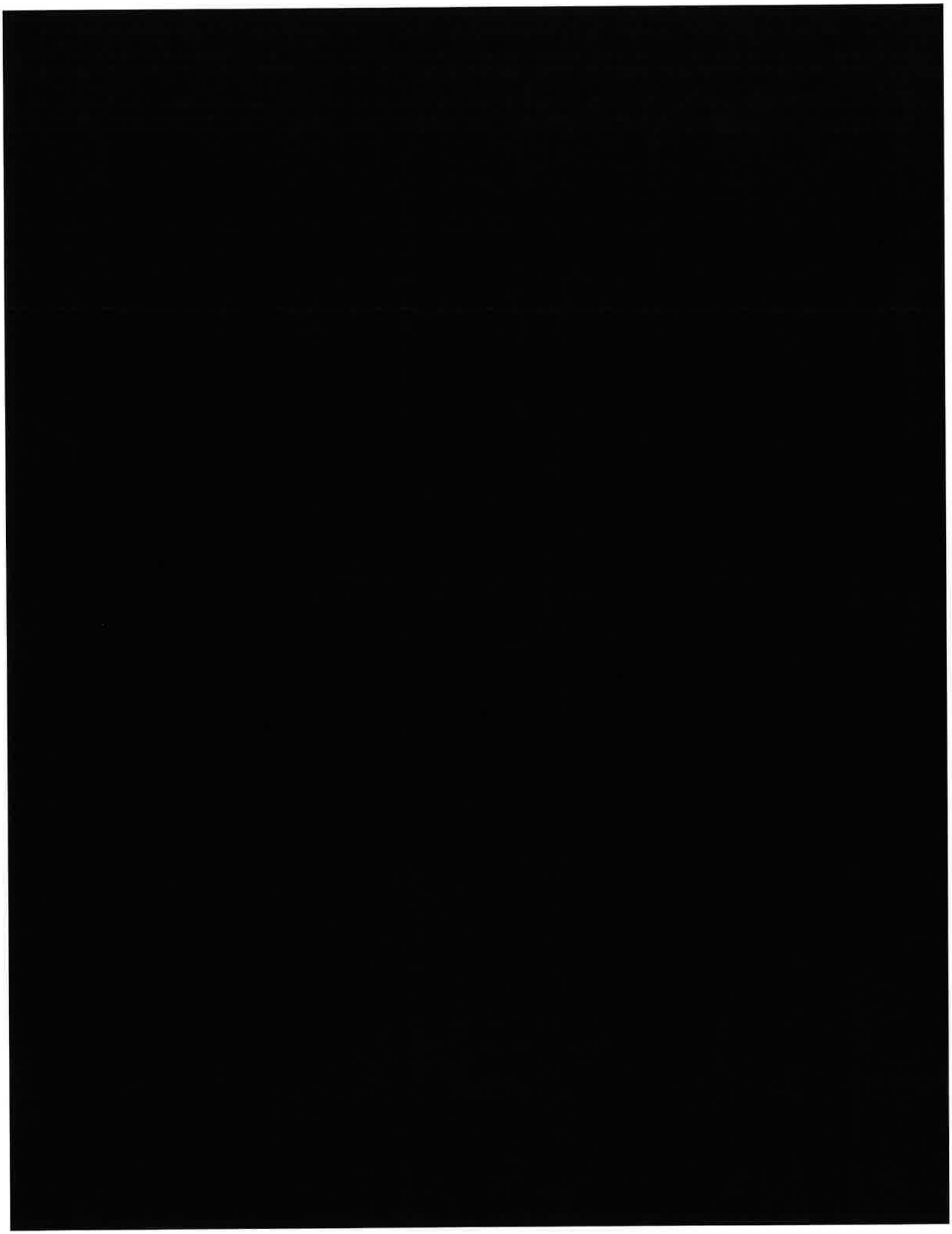


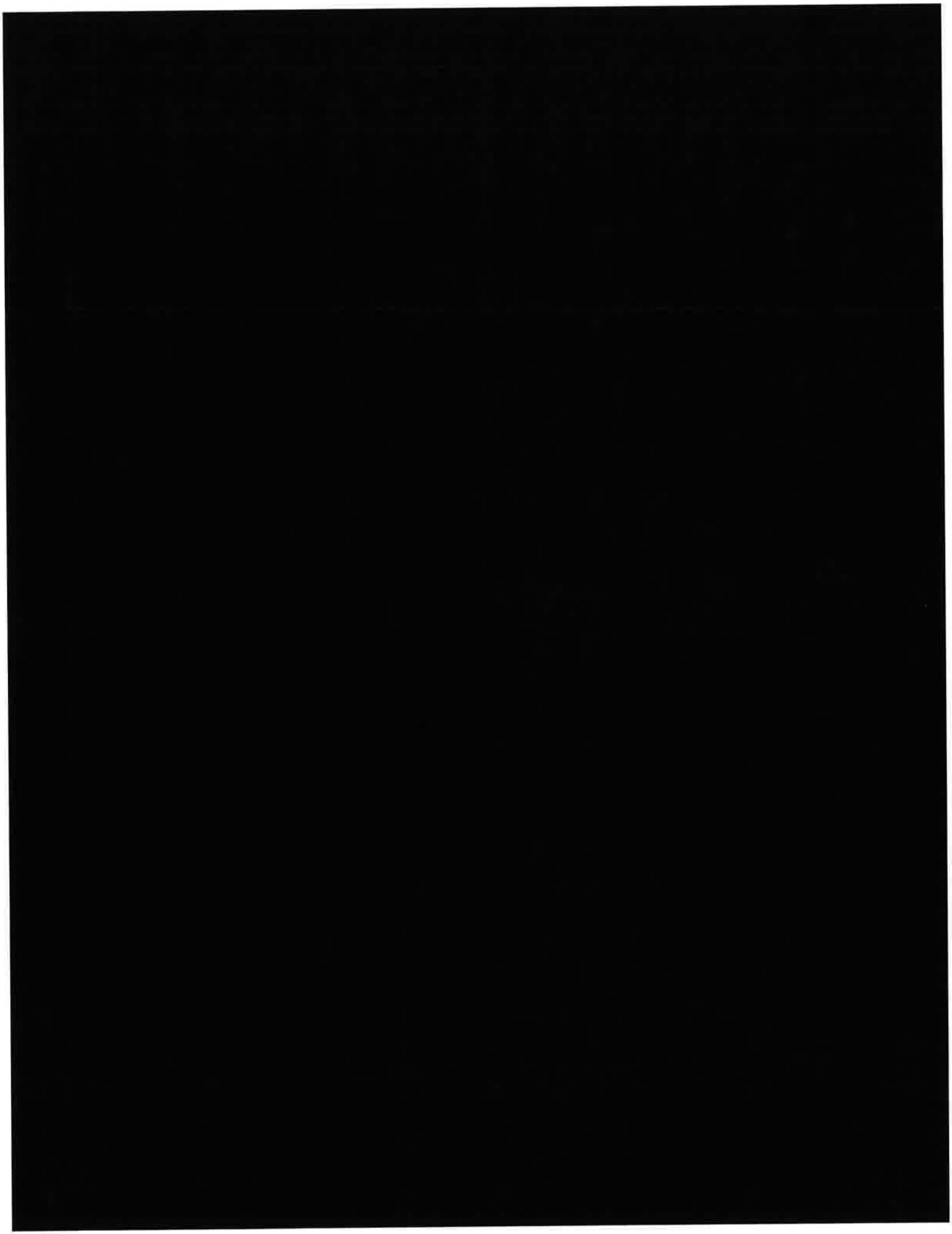


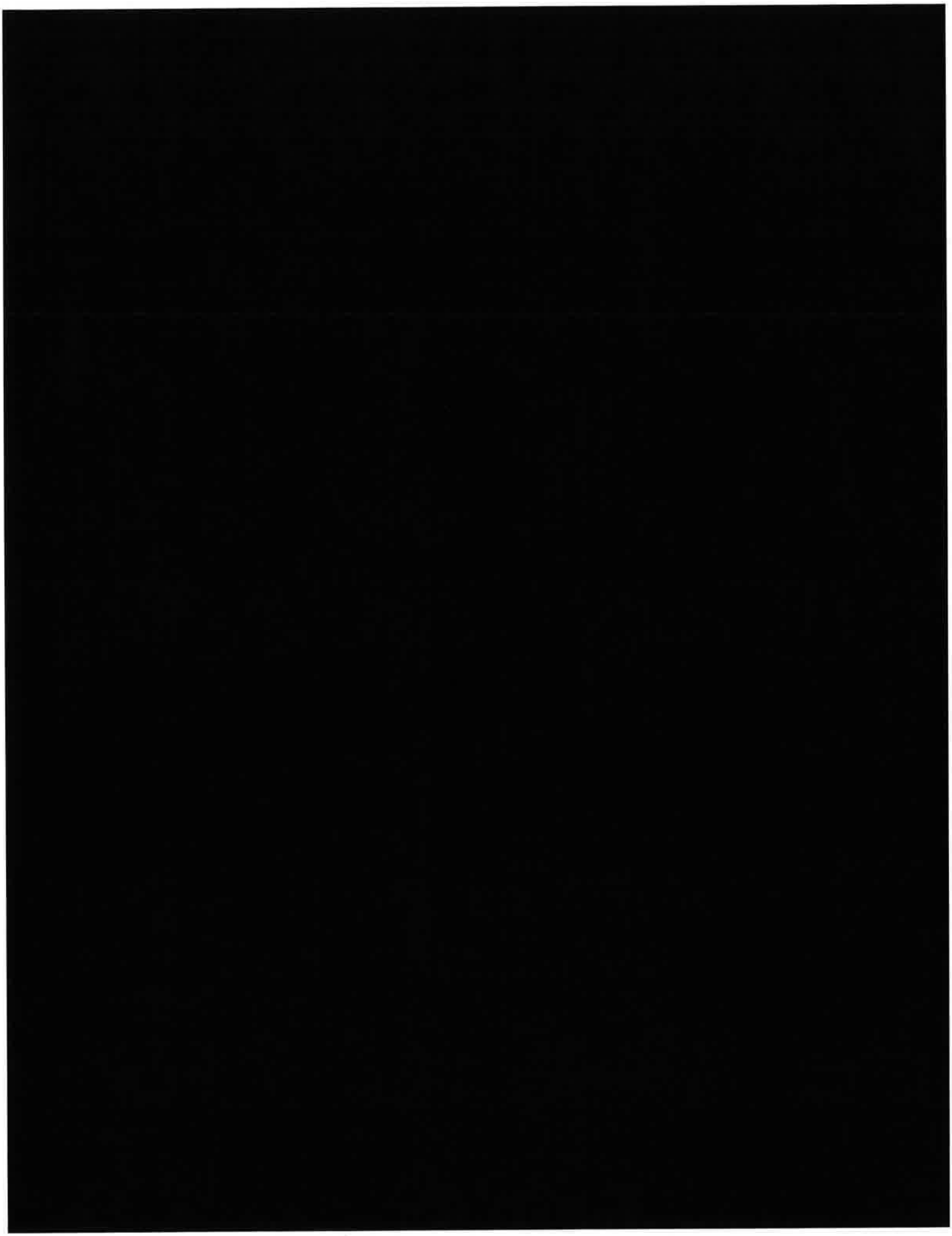


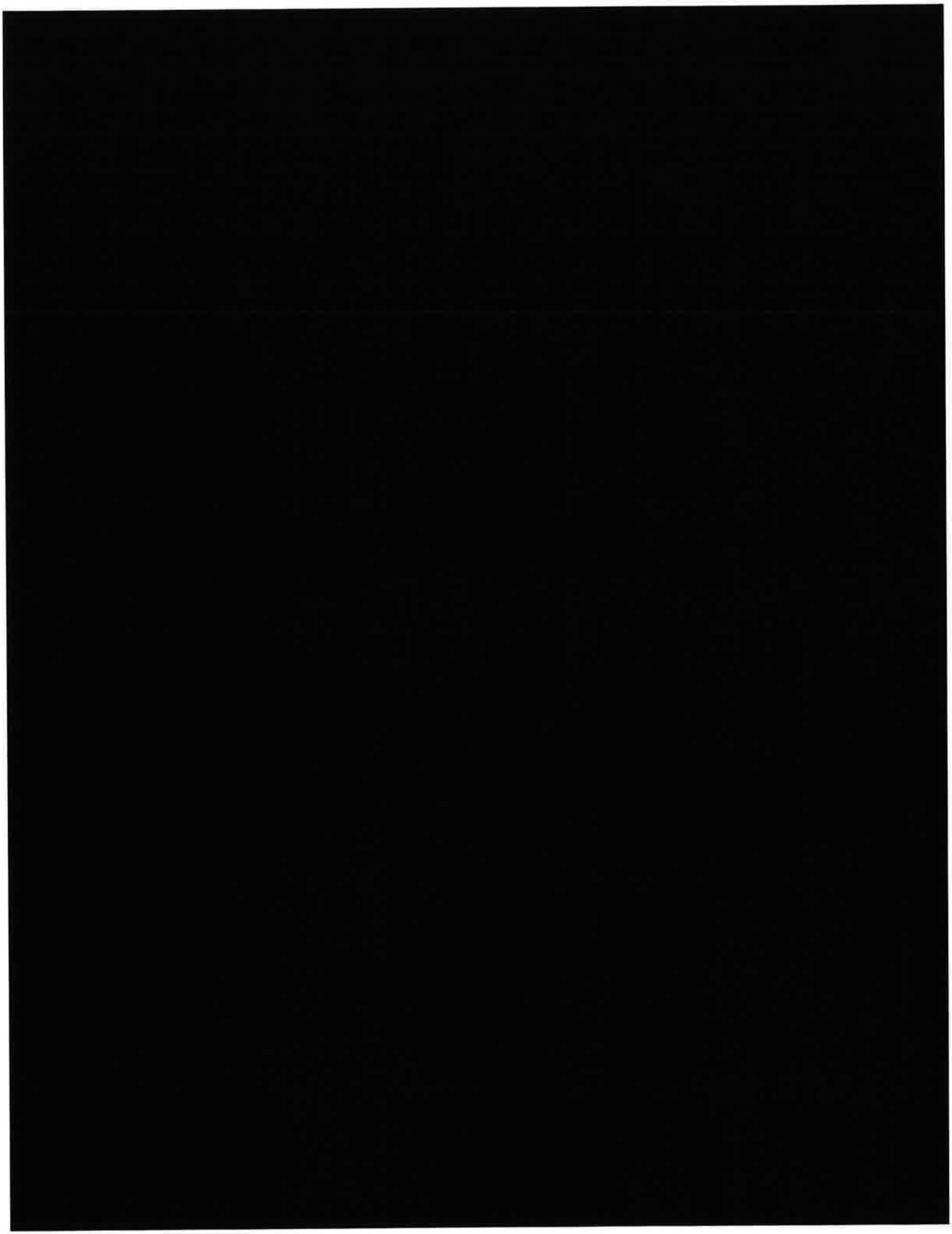


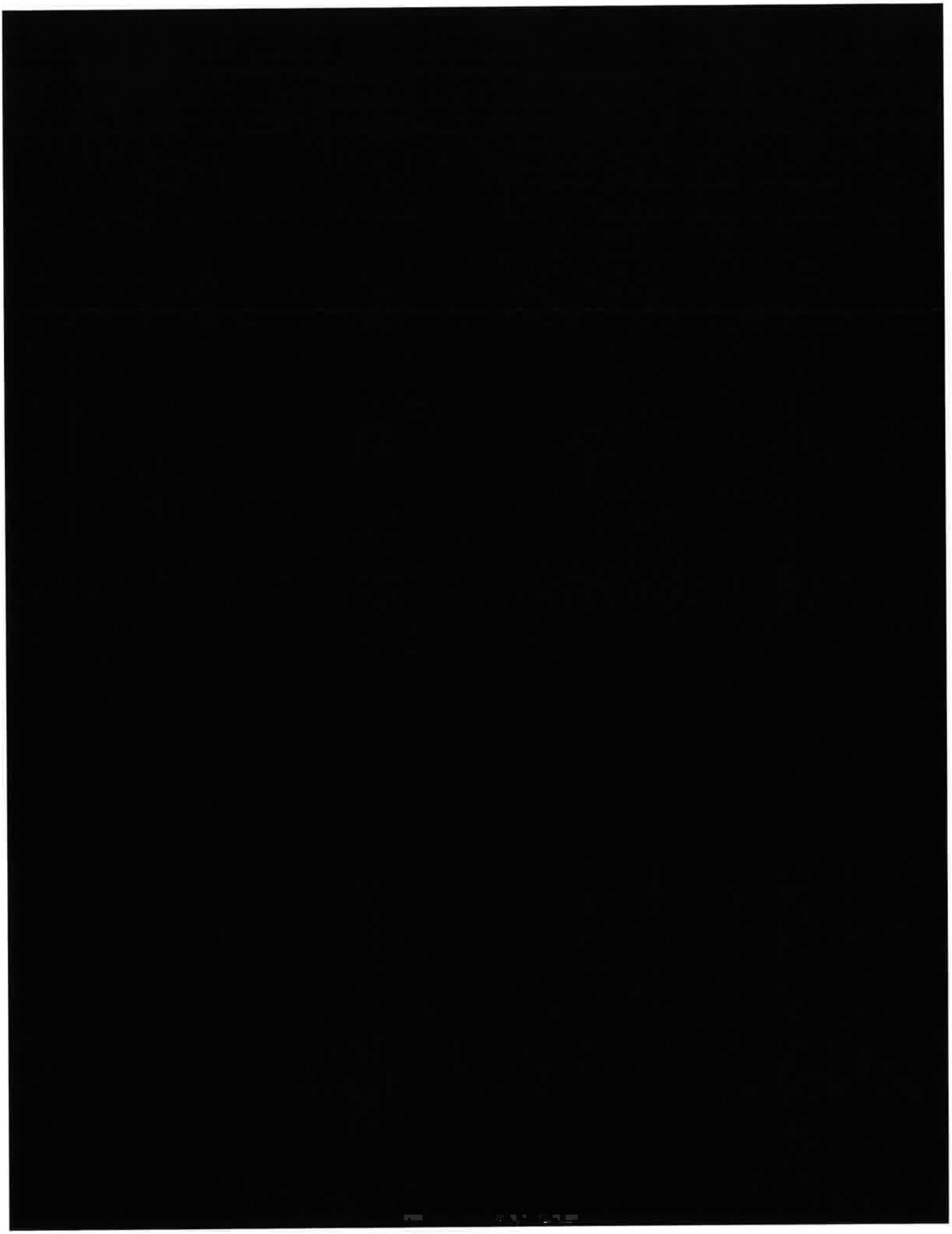


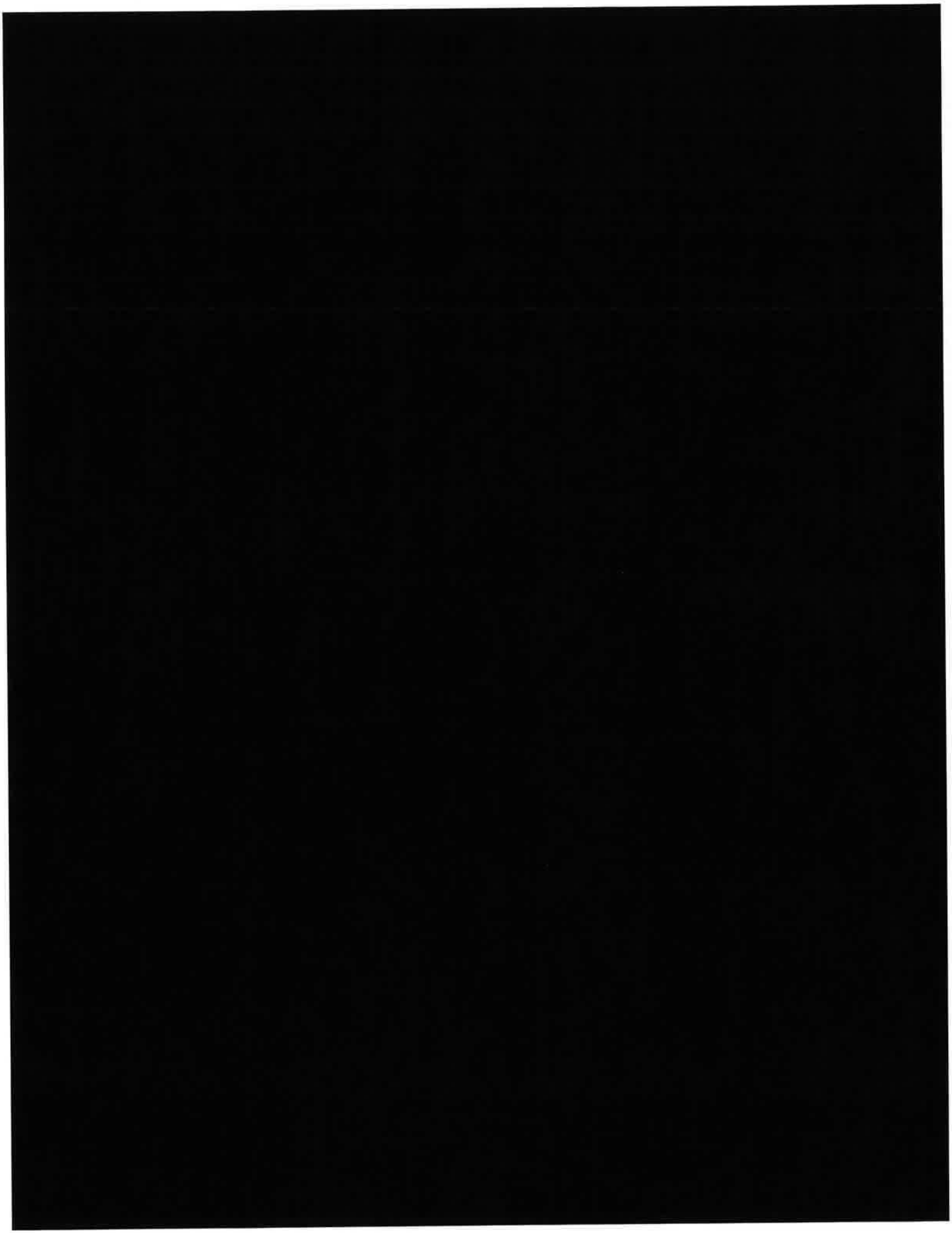


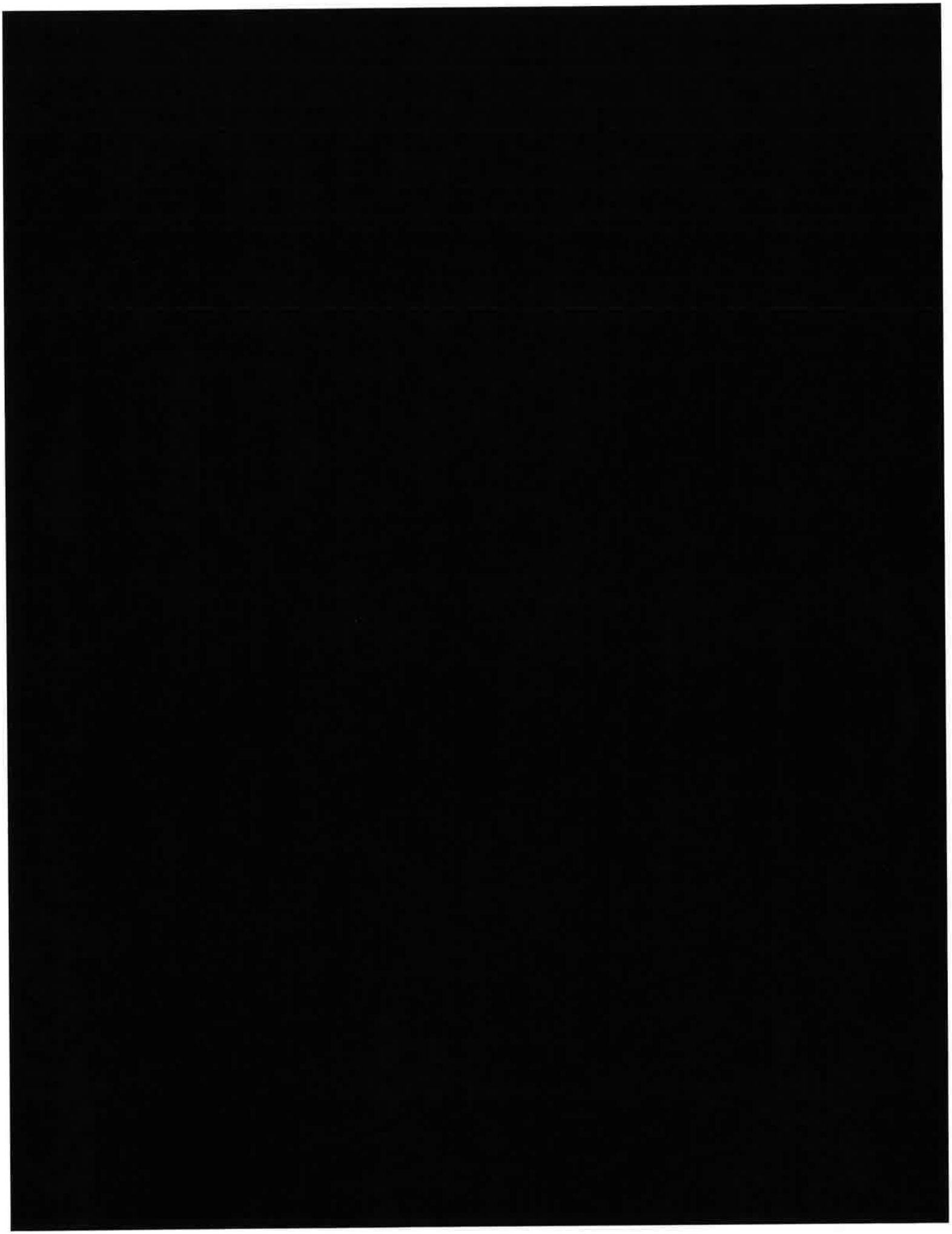


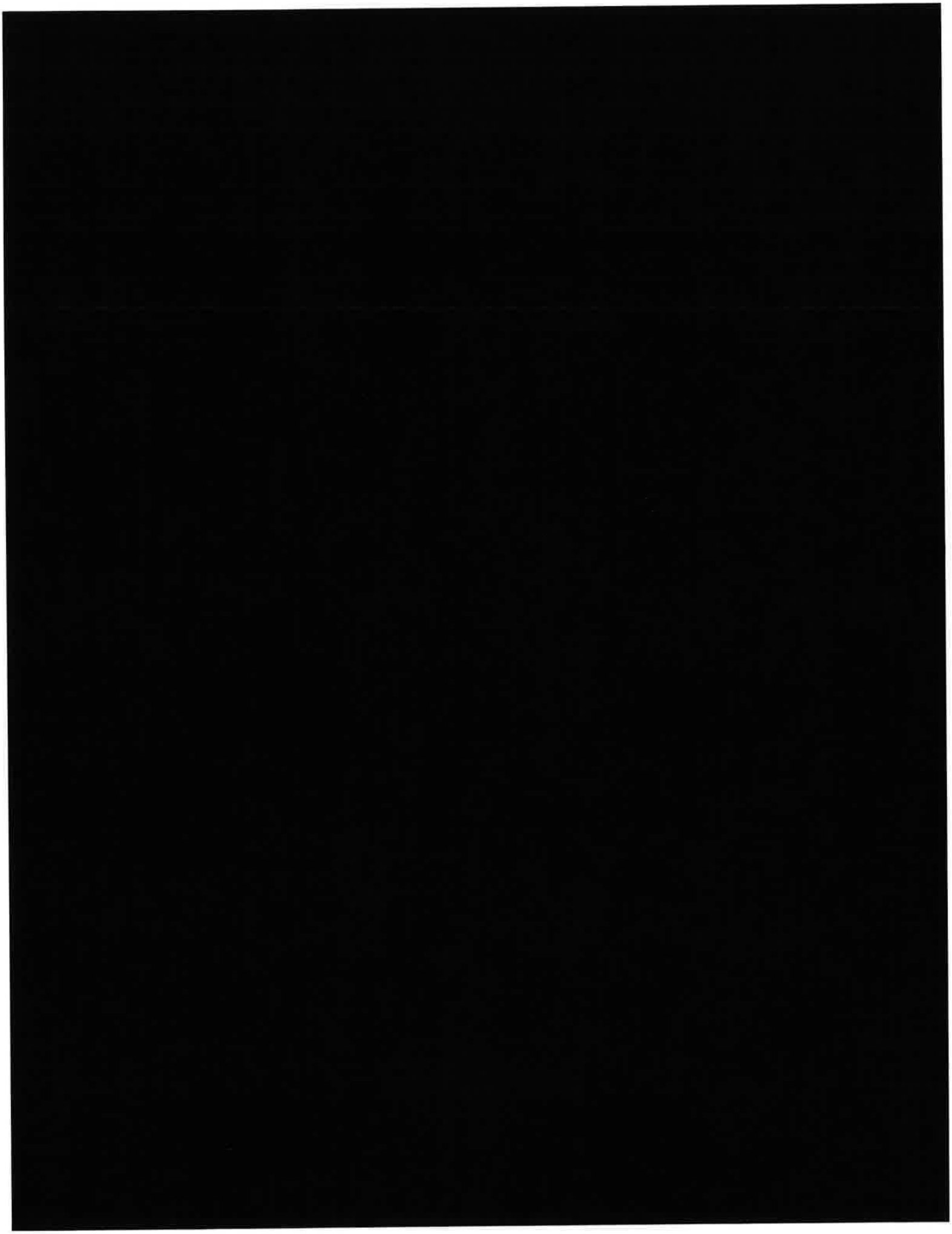


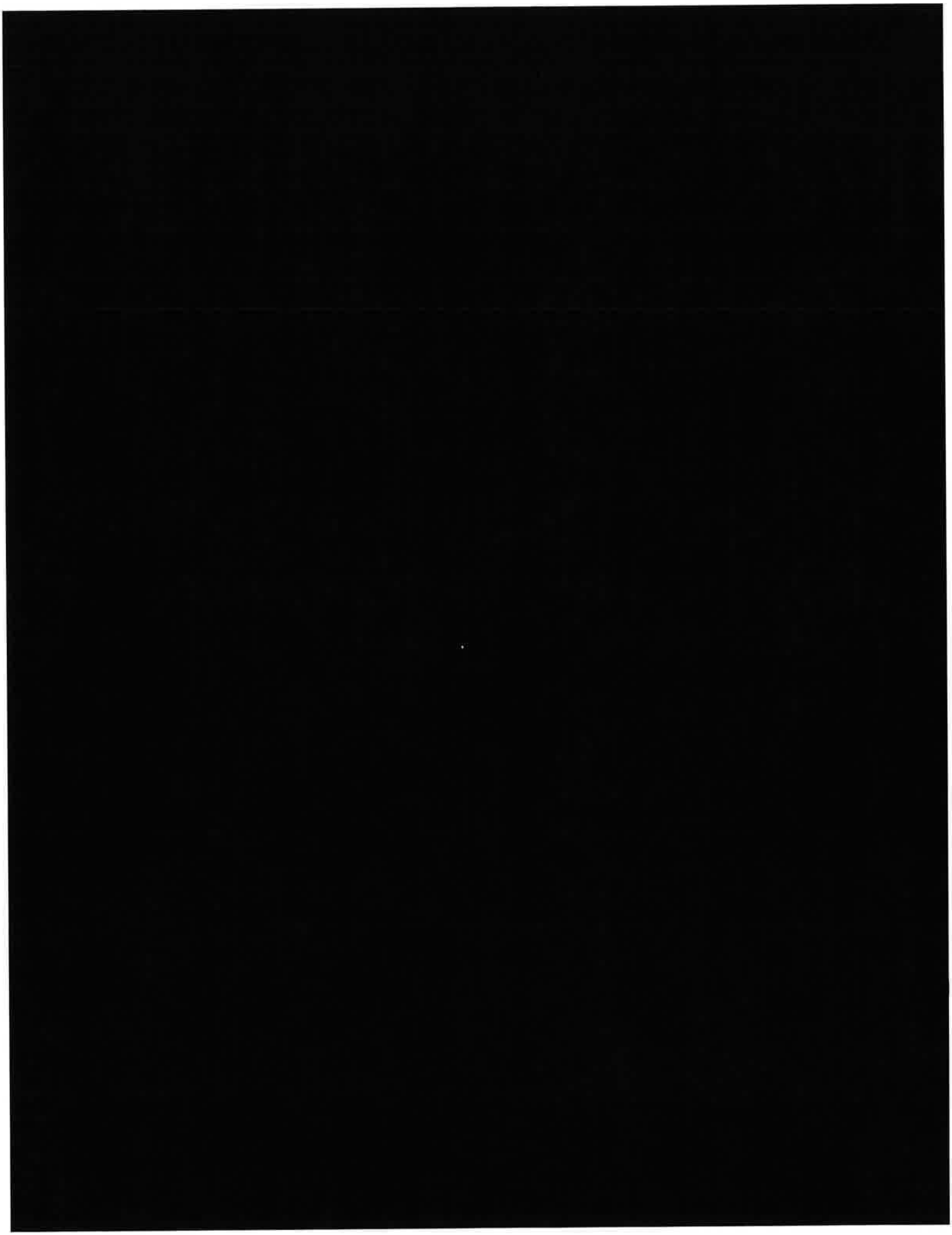


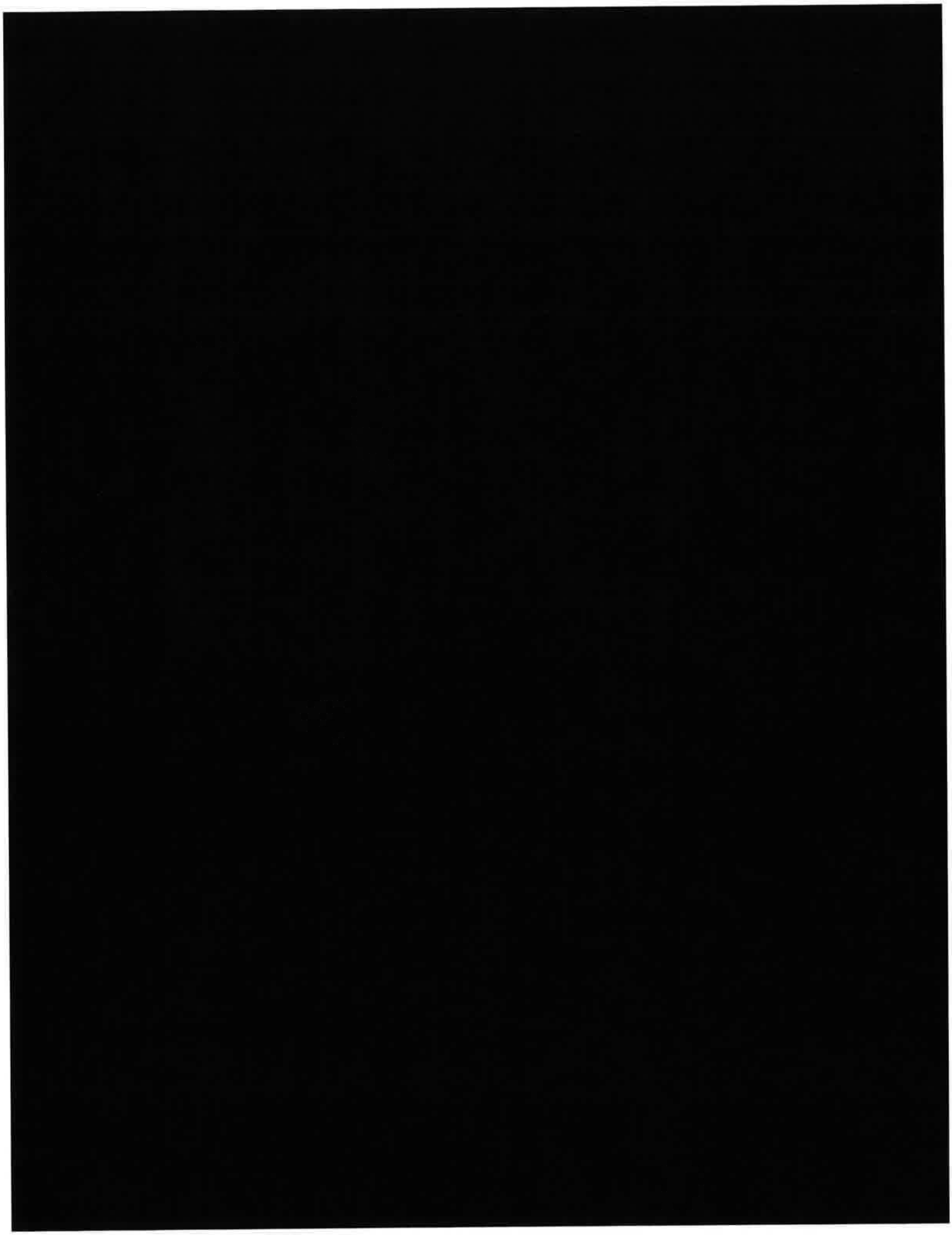


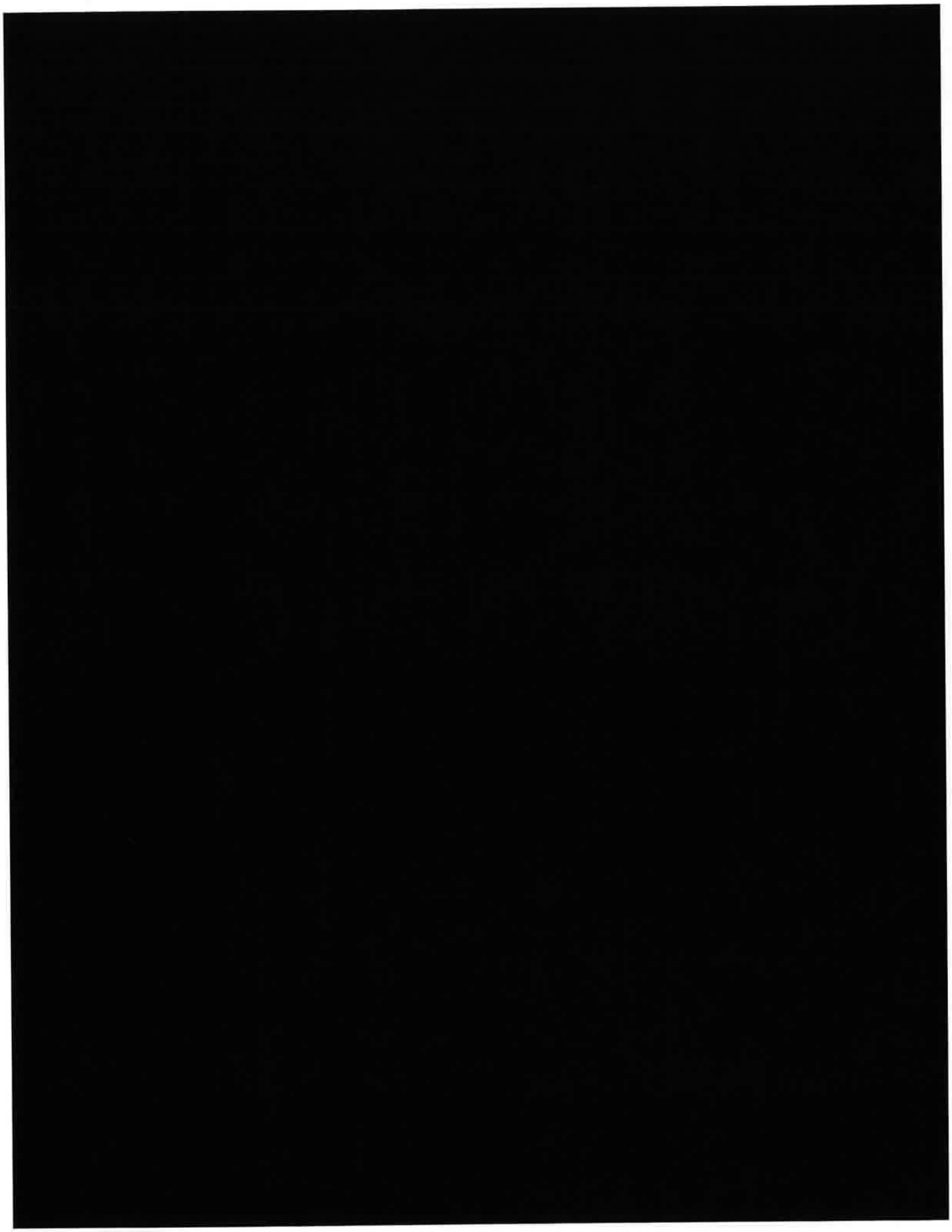


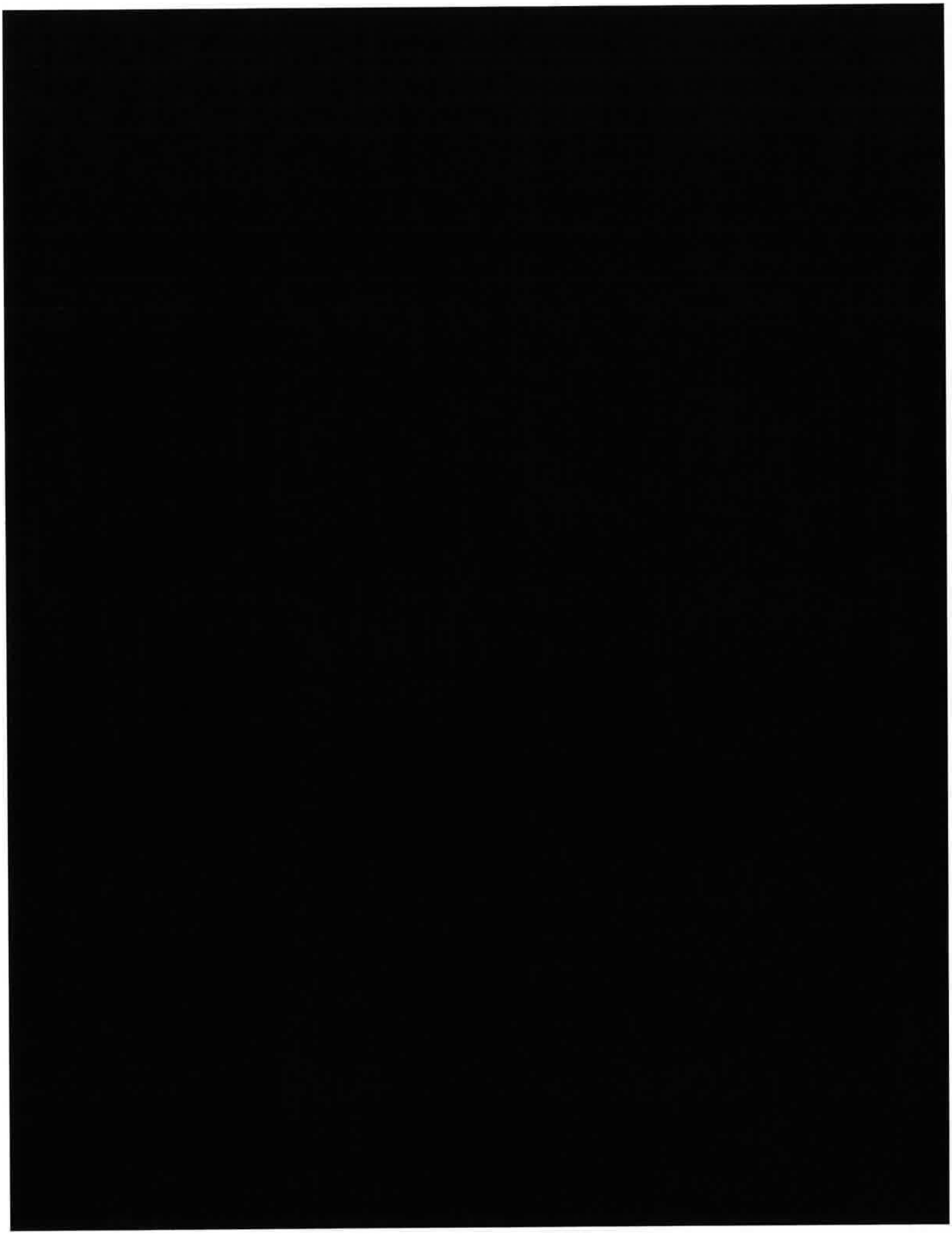


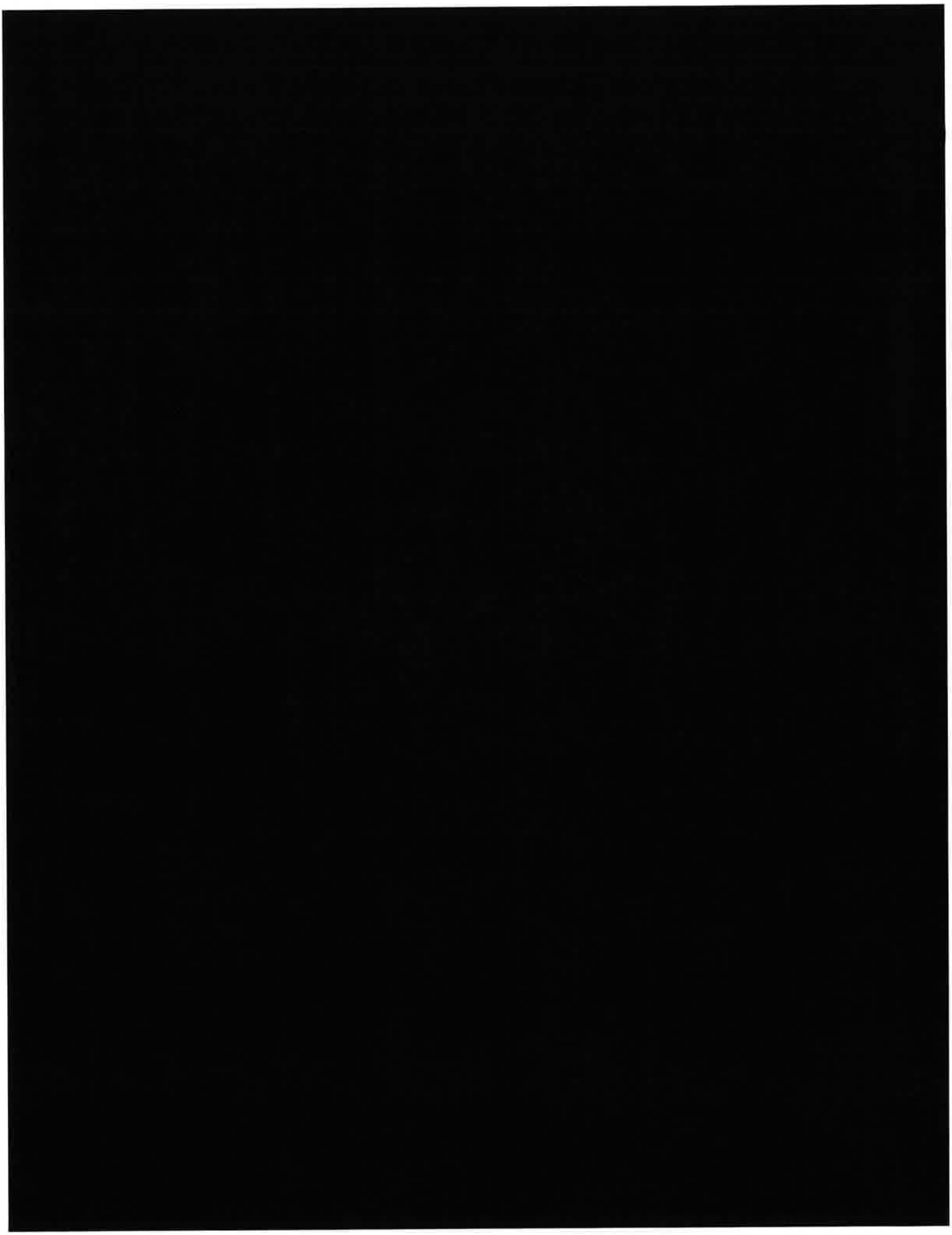


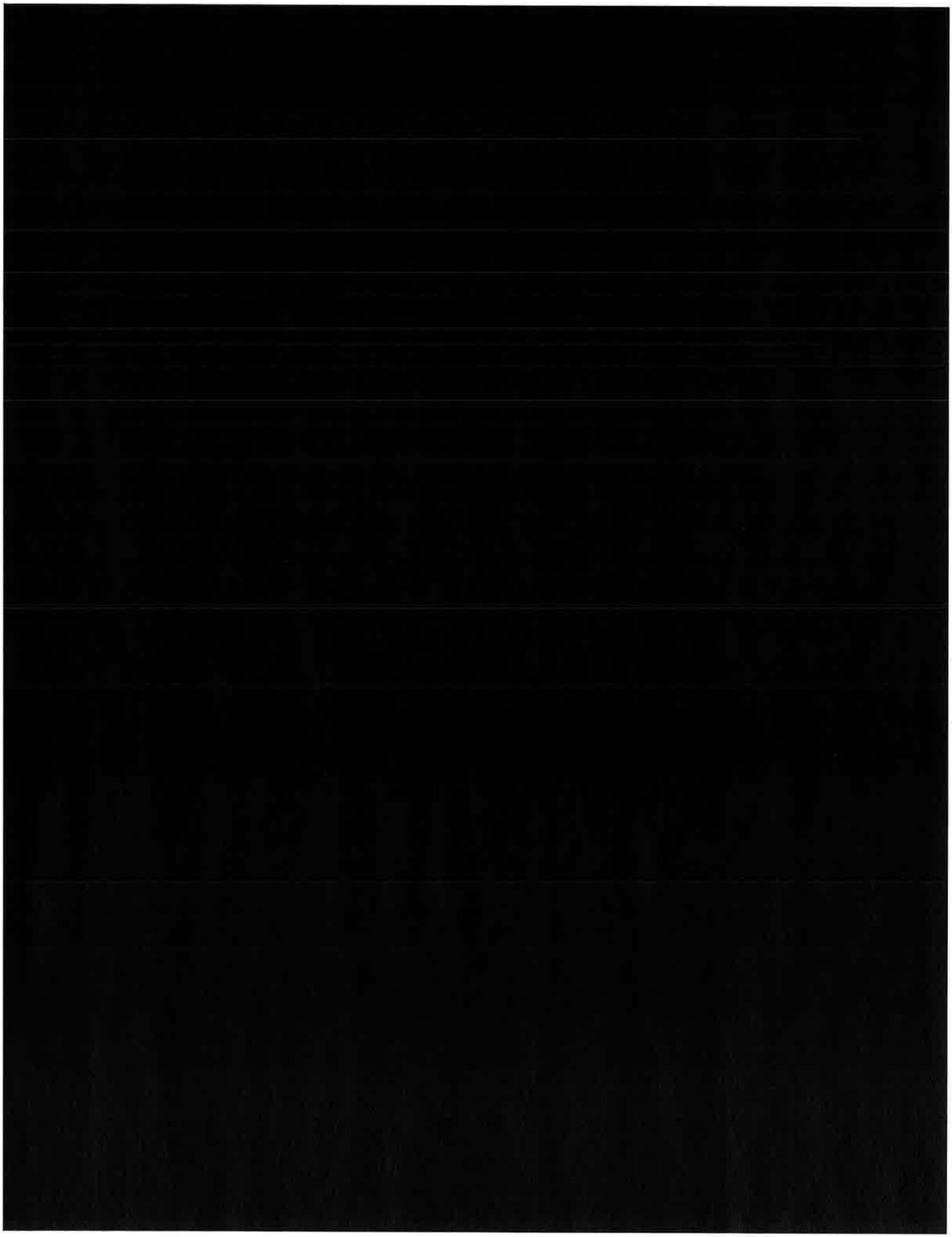


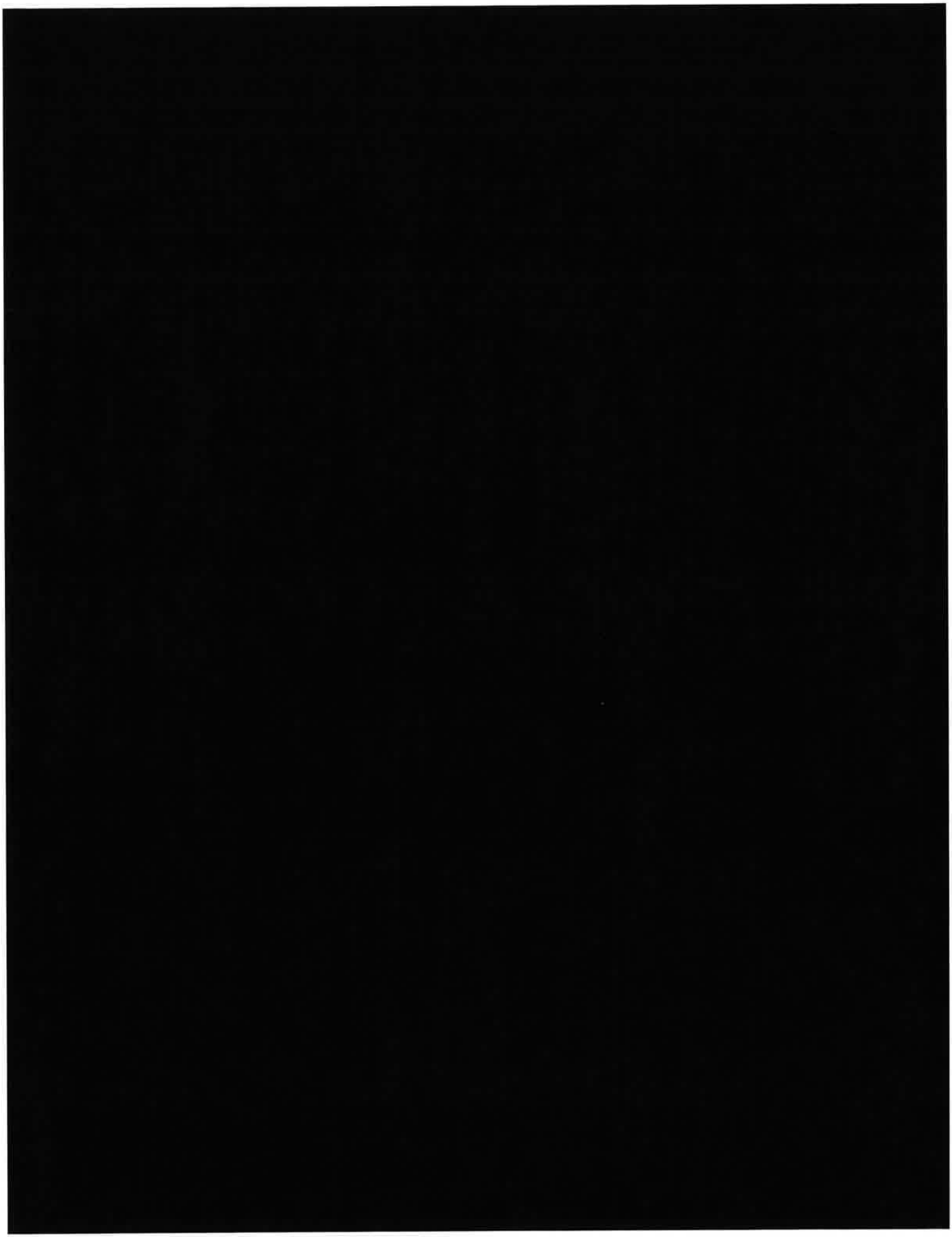












Idaho Power/502
Witness: Jared L. Ellsworth

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

Docket PCN 5

In the Matter of

IDAHO POWER COMPANY'S
PETITION FOR CERTIFICATE OF PUBLIC CONVENIENCE
AND NECESSITY

Updated BPA Letter to the Region
re: B2H and Southeast Idaho Load Service
(Jan. 9, 2023)

February 21, 2023

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

POWER SERVICES

January 9, 2023

In reply refer to: P-6

To parties interested in B2H and Southeast Idaho Load Service:

This notice announces that the Bonneville Power Administration, Idaho Power, and PacifiCorp have concluded negotiations on final agreements that memorialize and effectuate the Boardman to Hemingway, or B2H, with Transfer Service plan of service to southeast and southern Idaho loads. The proposed plan of service would deliver significant benefits for BPA and its customers, including essential congestion relief and removal of the dependence on conditional firm point-to-point service; consolidation of network integration transmission service from a single transfer service provider for all of BPA's deliveries to southeast and southern Idaho loads; and improved costs compared with today's interim service approach.

BPA now proposes to execute the contracts for the B2H with Transfer Service plan of service. Before making a final decision to execute the contracts, BPA is providing regional stakeholders with more information about the contracts and an opportunity to comment.

Attachment A includes background information, an overview of the contracts that BPA is proposing to execute for the B2H with Transfer Service plan of service, and information for how to submit comments.

We look forward to continued discussions with regional stakeholders on this important topic.

Sincerely,

Digitally signed by KIM THOMPSON
Date: 2023.01.09 10:01:57 -08'00'

Kim Thompson
Vice President, NW Requirements Marketing

MICHELLE MANARY
Digitally signed by MICHELLE MANARY
Date: 2023.01.09 10:00:24 -08'00'

Michelle Manary
Vice President, Transmission Marketing

Attachments

ATTACHMENT A

Updated BPA Letter to the Region re: B2H and Southeast Idaho Load Service

I. Background

In a Letter to the Region dated January 18, 2022 ("2022 Letter"), BPA announced its signature of a non-binding term sheet ("Term Sheet") that clarified and updated BPA's role in Idaho Power and PacifiCorp's potential future construction of their new transmission line from Boardman, Oregon to Hemingway, Idaho (the "Boardman to Hemingway Project" or "B2H"). The 2022 Letter provided background on the B2H negotiations, the history of BPA's load service to the six preference customers in Idaho ("Southeast Idaho Load Service" or "SILS customers"), and challenges with the current interim plan of service to these customers' loads. BPA explained how the proposed B2H project could provide BPA a long-term plan of service for the SILS customers that includes BPA taking network transfer service from Idaho Power ("B2H with Transfer Service"). BPA also explained the related challenges associated with BPA's long term service to the 15 preference customers in Southern Idaho, many located near Burley, Idaho, and the benefits that the B2H with Transfer Service plan of service provides to these customers. BPA noted that Idaho Power, PacifiCorp, and BPA intended to negotiate binding contracts to memorialize and effectuate the B2H with Transfer Service plan of service. The 2022 Letter and the Term Sheet are available at Southeast Idaho Load Service - Bonneville Power Administration (bpa.gov).

BPA is pleased to share that negotiations have concluded. BPA now proposes to execute binding contracts for the B2H with Transfer Service plan of service. Before making a final decision to execute the contracts, BPA is providing regional stakeholders with more information about the contracts and an opportunity to comment. BPA is also conducting appropriate National Environmental Policy Act ("NEPA") processes before making a final decision.

Under the B2H with Transfer Service plan of service, BPA's role as permitting partner and potential future partial owner of the B2H project would be removed from the B2H ownership structure. BPA would transfer its B2H permitting interest share to Idaho Power in a Purchase, Sale, and Security Agreement. Idaho Power and PacifiCorp would jointly own and construct the B2H project pursuant to separate agreements between them. To serve the SILS customers' loads, BPA would enter into a network integration transmission service agreement ("NITSA") with Idaho Power under its Open Access Transmission Tariff ("OATT") for service to the five SILS customers in the Goshen area and a second NITSA for service to Idaho Falls. These NITSAs would provide BPA with a single leg of network integration transmission service ("NITS") from Idaho Power to deliver resources from the BPA transmission system to the SILS customers' various points of delivery.

To facilitate Idaho Power's ability to serve the SILS customers' loads as network loads, PacifiCorp would transfer assets to Idaho Power in an agreement between PacifiCorp and Idaho Power. This asset transfer allows the SILS customers' loads currently served on PacifiCorp's southeast Idaho transmission system to be served fully on Idaho Power's transmission system. In consideration of PacifiCorp transferring assets to Idaho Power and with other stipulations, BPA would provide point-to-point ("PTP") transmission service in central Oregon to PacifiCorp

through the redirect of existing PTP service paired with a conversion of legacy scheduling rights in central Oregon to PTP service. Additionally, BPA would provide Idaho Power with PTP service to the B2H interconnection at the proposed BPA Longhorn substation near Boardman, Oregon. PacifiCorp and Idaho Power would take and pay for the PTP services pursuant to BPA's OATT and rate schedules. BPA would also enter into contracts with Idaho Power and PacifiCorp associated with the B2H interconnection at the proposed BPA Longhorn substation.

For BPA, the construction of B2H by Idaho Power and PacifiCorp in conjunction with the transfer of assets between Idaho Power and PacifiCorp means that BPA would receive firm network transmission service for its SILS customer loads using only one wheel of transmission beyond the BPA transmission system (as opposed to two wheels, which is part of the current interim plan of service). By stepping out of the B2H ownership structure, BPA also avoids the complexity and foregone revenue of other previously considered plans of service.

This letter announces the final terms of the B2H with Transfer Service plan of service. Section II describes the agreements that BPA proposes to execute. Section III provides an explanation of BPA's business case for this plan of service, including the quantitative and qualitative benefits. Key benefits include elimination of today's reliance on conditional firm PTP service for deliveries of BPA resources to the SILS customers' loads, migration of SILS customer loads to firm network transmission service, financial benefits of having a single wheel of transmission for service to the SILS customer and incremental revenues from new PTP sales, congestion relief that benefits BPA's deliveries for all Southern and Southeast Idaho customers, and eliminating today's interim service's reliance on market purchases that carry cost, availability, and carbon-content risks.

Finally, this letter initiates the start of a public comment period that will conclude on February 9, 2023. Section IV provides information for how stakeholders may submit comments. BPA will answer stakeholder questions and discuss aspects of the business case associated with the B2H with Transfer Service plan of service at the January 23, 2023, workshop. BPA intends to make a final decision regarding whether to execute the agreements for the B2H with Transfer Service plan of service in a Closeout Letter to the region on or about March 23, 2023.

II. Final Terms for the B2H with Transfer Service Plan of Service

A. Arrangements to effectuate long-term firm transfer service for the SILS customers' loads

Under the B2H with Transfer Service plan of service, BPA would not become an owner or participate in the construction of the B2H project. Instead, BPA would sell its B2H permitting interest share (around 24%) and its right to future ownership in B2H to Idaho Power. Together with Idaho Power's existing rights to the B2H project, this sale of BPA's permitting interest would allow Idaho Power to fund construction and hold a 45.45% ownership share in the B2H project. PacifiCorp would continue to fund construction and hold a 55.55% ownership share in the B2H project.

To serve the SILS customers' loads after the B2H project is constructed, BPA would purchase long-term firm NITS from Idaho Power. Currently, service to the SILS customers' loads uses transmission facilities that are owned by PacifiCorp. In order to facilitate Idaho Power's ability to serve the SILS customers' loads entirely from its transmission system after the B2H project is constructed, PacifiCorp would transfer an ownership interest to Idaho Power in the PacifiCorp facilities that are presently used to serve BPA's SILS loads (the "asset exchange"). In addition, BPA would pay Idaho Power $10 million upon execution of the NITSAs as security for Idaho Power's construction of the B2H project to provide BPA with the NITS service. The security would allow Idaho Power to provide assurances to its regulatory bodies that its retail rate payers were insulated from risk associated with Idaho Power purchasing BPA's share of the B2H permitting interest.

Following execution of the Term Sheet, Idaho Power and BPA merged the terms for the sale of BPA's permitting interest and the NITSA security payment into a single agreement, the Purchase, Sale, and Security Agreement, because the subject matters were interrelated. The key provisions of the Purchase, Sale, and Security Agreement, NITSAs, and agreements between Idaho Power and PacifiCorp needed to serve the SILS loads are described below. If BPA's final decision is to proceed with the B2H with Transfer Service plan of service, BPA would execute these agreements concurrent with issuing the Closeout Letter.

1. Purchase, Sale, and Security Agreement

In the Purchase, Sale, and Security Agreement, BPA would transfer its permitting interest share to Idaho Power in exchange for payment to BPA for the costs BPA incurred towards permitting the B2H project (around $30 million). BPA would also pay Idaho Power the $10 million security payment. The payment for the value of the permitting interest and the security is the Purchase Price. The agreement sets forth the requirements associated with the reimbursement of the Purchase Price to address the risks and uncertainties associated with Idaho Power taking on a larger ownership share in the B2H project and constructing a major new transmission line to provide BPA with NITS service.

If Idaho Power successfully completes construction and energization of the B2H project by the milestones in the Purchase, Sale, and Security Agreement, Idaho Power would return the $10 million security to BPA within 60 days of energization of the B2H project. The remaining amount of the Purchase Price would be paid in installments based on a 20 year payment schedule. The first installment of the Purchase Price payment would begin 10 years after B2H is energized, provided that BPA takes the NITS service from Idaho Power during those 10 years. Additionally, during those 10 years of NITS service, BPA's NITS loads must reach 400 MW or more on the hour of Idaho Power's transmission system peak on a twelve-month rolling average basis. If BPA's NITS loads do not reach the 400 MW threshold during the initial 10 years of service, Idaho Power would begin repaying BPA the Purchase Price on the next year after the 400 MW threshold is met.

The Purchase, Sale, and Security Agreement also addresses reimbursement of the Purchase Price to BPA if problems arise with Idaho Power completing construction and energization of the B2H project:

- If Idaho Power does not receive the necessary governmental authorizations and, as a result, cannot complete the B2H project to provide NITS service to BPA, Idaho Power would not be obligated to pay the Purchase Price to BPA. BPA is agreeing to accept this financial risk because Idaho Power would be funding a higher percentage of B2H costs in order to provide BPA with NITS service under the B2H with Transfer Service plan of service.

- If Idaho Power does not receive governmental authorization by January of 2025, and has not commenced construction by January of 2026, or other timeline as mutually agreed to by BPA and Idaho Power, BPA would have the option to terminate the NITSAs. The option to terminate the NITSAs allows BPA to pursue an alternative plan of service for the SILS loads if there is substantial risk that the B2H project would not be completed.

    - If BPA exercises the option to terminate the NITSAs and Idaho Power ultimately receives governmental authorizations and completes the B2H project, Idaho Power would return the security to BPA and pay the remaining amount of the Purchase Price. If Idaho Power does not complete the B2H project, then Idaho Power is relieved of the obligation to pay BPA the Purchase Price.

    - If BPA does not exercise the option to terminate the NITSAs and Idaho Power ultimately completes the B2H project, then Idaho Power would pay BPA the Purchase Price based on the installment payment schedule described above.

- If Idaho Power receives all necessary governmental authorizations by January of 2025, but decides to no longer proceed with constructing and energizing the B2H project, Idaho Power would return the security to BPA. Additionally, Idaho Power must attempt to market the transferred permitting interest. Idaho Power would then pay BPA for its proportional share of the sale proceeds.

The Purchase, Sale, and Security Agreement generally reflects the deal and structure envisioned in the Term Sheet. The 400 MW limit is a new term that the parties negotiated after execution of the Term Sheet to allow Idaho Power to provide assurances to its regulatory bodies that its retail ratepayers were insulated from risk associated with Idaho Power purchasing BPA's share of the B2H permitting interest. The Term Sheet also contemplated that Idaho Power would return security amounts as credits offsetting BPA's NITSA bills. The Purchase Price payments will be independent of the NITSA billing.

2. NITS Agreements with Idaho Power

For the B2H with Transfer Service plan of service, BPA would enter into two new long-term firm NITSAs with Idaho Power. One new NITSA would provide for service to the Goshen area customers (Lower Valley, Soda Springs, Fall River, Lost River, and Salmon River) ("Goshen NITSA"). A second new NITSA would provide service for Idaho Falls ("Idaho Falls NITSA"). The Goshen and Idaho Falls NITSAs, together with the asset exchange between Idaho Power and PacifiCorp, would allow BPA to deliver energy to the SILS customers' loads from BPA's

transmission system on a single leg of firm network transmission service across Idaho Power's system as opposed to relying on the conditional firm service under the interim plan of service. Finally, BPA would update three existing NITSAs that support service to BPA's Southern Idaho customers.

Service under the Goshen and Idaho Falls NITSAs would commence after two conditions precedent are satisfied. First, Idaho Power must complete construction and energization of the B2H project. Second, Idaho Power and PacifiCorp must exchange assets sufficient to enable Idaho Power to deliver resources from the BPA transmission system across the Idaho Power system on a single leg of transmission to the SILS customers' loads (see subsection 3 below). Commensurate with the asset exchange, the SILS customers' loads under the Goshen NITSA would move from the PacifiCorp Balancing Authority Area to the Idaho Power Balancing Authority Area. Arrangements for the Idaho Falls NITSA are described below.

After these conditions precedent are met, service under the Goshen and Idaho Falls NITSAs would commence upon energization of B2H, or a later date if specified by the Federal Energy Regulatory Commission (Idaho Power must obtain regulatory approval from the Commission for the NITSAs). Service under the NITSAs would terminate on July 1, 2046, and could be rolled over for additional terms consistent with Idaho Power's OATT.

The NITSAs also include an assignment provision that would allow BPA to request assignment of some or all of the service under the NITSA to the wholesale customers that are served by the NITSA. Idaho Power may not unreasonably withhold its consent to such assignment, provided the wholesale customer qualifies as an Eligible Customer consistent with Idaho Power's OATT and assumes BPA's rights and obligations under the assigned NITSA.

Idaho Falls would be served under a separate NITSA because of its unique supply arrangements with other parties. Idaho Falls currently purchases BPA's slice/block product and is responsible for managing its hourly balancing needs. Idaho Falls contracts with Utah Associated Municipal Power Systems ("UAMPS") for this balancing service, which UAMPS provides under a legacy transmission service agreement with PacifiCorp to balance the Idaho Falls load in the PacifiCorp Balancing Authority Area. Due to this unique arrangement and after discussion with Idaho Falls, BPA determined that it was reasonable to negotiate a separate NITSA for Idaho Falls. One of BPA's objectives in negotiating the Idaho Falls NITSA was to ensure that there was no impact to the existing relationship between Idaho Falls and UAMPS, or the legacy agreement between UAMPS and PacifiCorp. Accordingly, the Idaho Falls NITSA would only serve the portion of Idaho Falls load served by BPA resources.

With regard to the updates to existing NITSAs, BPA has three existing NITSAs with Idaho Power. BPA uses these NITSAs to serve 15 preference customers, including the customers in the Burley area, and to deliver reserve power to the United States Bureau of Reclamation and irrigation customers. Idaho Power has identified transmission constraints associated with serving increased loads under these NITSAs. One of the key benefits associated with the completion and energization of the B2H project is that B2H increases the capacity on Idaho Power's system that could be used to serve future load growth for these customers. After B2H is energized, these existing NITSAs would be updated to include a new B2H point of receipt that BPA can use to

deliver resources from the BPA transmission system to BPA's customers located on Idaho Power's system.

3. Agreements between Idaho Power and PacifiCorp

As noted above, concurrently with BPA executing the Purchase, Sale, and Security Agreement to divest BPA of any interest in the B2H project, Idaho Power and PacifiCorp would enter into agreements for the continued funding of the B2H project, including permitting, preconstruction, and construction (with Idaho Power funding 45.45% of all further costs associated with the B2H project). Idaho Power and PacifiCorp would also enter into other agreements necessary for ownership and the ongoing operation and maintenance of the B2H project. In addition, Idaho Power and PacifiCorp would proceed with obtaining all state and federal regulatory approvals applicable to them.

With regard to the asset exchange that is a key feature of the B2H with Transfer Service plan of service, Idaho Power and PacifiCorp would enter into an agreement to transfer Goshen area assets from PacifiCorp to Idaho Power. In many instances, these assets are already jointly owned by Idaho Power and PacifiCorp, so the asset exchange would adjust the ownership share of the jointly owned facilities to increase Idaho Power's share. The asset exchange would commence upon the energization of B2H and the NITSAs between BPA and Idaho Power.

BPA is not a party to the agreements between Idaho Power and PacifiCorp. If BPA's final decision is to proceed with B2H with Transfer Service, Idaho Power and PacifiCorp would execute the contracts they would be party to concurrent with BPA executing the contracts that BPA would be party to. Questions or comments about the agreements between Idaho Power and PacifiCorp or about the permitting and construction of the B2H project should be directed to Idaho Power and PacifiCorp. For more information about Idaho Power and PacifiCorp's B2H transmission line project, please visit Boardman to Hemingway - Idaho Power.

B. Transmission Agreements with PacifiCorp and Idaho Power

Under the B2H with Transfer Service plan of service, BPA would provide PTP transmission service to PacifiCorp and Idaho Power pursuant to BPA's OATT and rate schedules. Additionally, BPA would enter into other transmission arrangements with Idaho Power and PacifiCorp related to the interconnection of the B2H project with the proposed BPA Longhorn substation. This section describes these transmission arrangements.

1. BPA providing PTP service to PacifiCorp

The 2022 Letter explained that, in consideration for PacifiCorp transferring its Goshen assets to Idaho Power, BPA and PacifiCorp would evaluate options for BPA to provide PacifiCorp with 680 MW of firm PTP service at or near the 230kV side of the Ponderosa substation (Ponderosa 230) in central Oregon. BPA's evaluation would be consistent with BPA's OATT and business practices and would consider a 2021 joint study. The preferred option included conversion of PacifiCorp's legacy bidirectional scheduling rights over BPA's Buckley-Summer Lake line to PTP service. The transmission capacity associated with the conversion would be combined with

PacifiCorp requesting to redirect existing PTP service. PacifiCorp would pay for the PTP service pursuant to BPA's OATT and posted transmission rates. The second, back-up, option involved changes to how PacifiCorp scheduled the legacy bidirectional scheduling rights with other limitations.

As noted above, the Term Sheet provided that BPA's evaluation would take into consideration a 2021 joint study performed by BPA, Idaho Power, and PacifiCorp as well as two series capacitor projects identified in the study that Idaho Power and PacifiCorp intended to install. For one of the projects, Idaho Power and PacifiCorp would install a series capacitor around the midpoint of the B2H line and develop a remedial action scheme ("Midline Series Capacitor Project"). For the other project, PacifiCorp would upgrade the existing series capacitor at the Meridian substation or install an electrically equivalent series capacitor ("Meridian Series Capacitor Project"). The joint study demonstrated that these series capacitor projects would improve performance of the transmission system with B2H in service and would allow BPA to accommodate the PTP service PacifiCorp sought as compared to the existing system configuration. The Midline and Meridian Series Capacitor Projects enhance system stability and allow flows to be shifted from more constrained transmission facilities to less constrained parallel facilities. Both of these factors help to optimize the utilization of the overall transmission system. The 2021 joint study provides useful information, but does not serve as a replacement for PacifiCorp submitting transmission requests and BPA evaluating those requests consistent with BPA's OATT and applicable business practices. Therefore, the Term Sheet specified that PacifiCorp would need to submit transmission service requests so that BPA could do the OATT evaluation.

Following execution of the Term Sheet, BPA and PacifiCorp aligned on the details for the PTP redirect requests that would be paired with the conversion of the legacy scheduling rights under the preferred option. The second, back-up option was determined to be unworkable and did not receive further consideration. In April and June, 2022, PacifiCorp submitted the PTP redirect requests over BPA's OASIS. The following table describes the requests:

Parent (Existing) Reservation	**Redirect Reservation**
70 MW from Garrison 500 to Buckley 500	70 MW from Garrison 500 to Ponderosa 230
70 MW from McNary 230 to Buckley 500	70 MW from McNary 230 to Ponderosa 230
200 MW from Big Eddy 500 to Buckley 500	200 MW from Big Eddy 500 to Ponderosa 230
120 MW from Ponderosa 500 to Ponderosa 230	120 MW from Summer Lake 500 to Ponderosa 230
190 MW from Ponderosa 500 to Pilot Butte 230	190 MW from Summer Lake 500 to Pilot Butte 230
30 MW from Ponderosa 500 to Pilot Butte 230	30 MW from Summer Lake 500 to Pilot Butte 230

BPA evaluated the redirect requests consistent with its OATT and the standard evaluation processes, which are described in BPA's business practices including the Transmission Service Request Evaluation Business Practice. BPA's standard evaluation processes take into consideration existing obligations and higher queued requests. BPA evaluated the availability of

capacity to accommodate the conversion of the scheduling rights to PTP service based on the existing bidirectional capacity over the Buckley-Summer Lake line that PacifiCorp has been scheduling under the legacy contract (340 MW in the north-to south direction and 340 MW in the south-to-north direction). In order to pair the conversion with the redirect requests, BPA applied this bidirectional capacity to the redirected service. BPA then considered whether there were other impacts to the transmission system not reflected in the redirect and conversion analysis. Finally, BPA's consideration took into account the 2021 joint study and the installation of the series capacitor projects.

BPA concluded that the PTP service (the preferred option) can be accommodated with stipulations that are consistent with the Term Sheet. The PTP stipulations include the energization of the B2H project to include the Midline Series Capacitor Project, the installation of the Meridian Series Capacitor Project pursuant to a construction agreement between PacifiCorp and BPA, the transfer of the Goshen area assets between PacifiCorp and Idaho Power, and the commencement of BPA's Goshen and Idaho Falls NITSAs with Idaho Power.

Accordingly, BPA is proposing to execute several agreements with PacifiCorp concurrent with the issuance of the final decision in the Closeout letter. The PTP agreements with PacifiCorp reflect the service shown in the Redirect Reservation column of the table above and include conditions precedent to reflect the PTP stipulations. After the conditions precedent have been met, the service would commence upon energization of B2H. BPA also would execute an amendment to the legacy agreement with PacifiCorp to remove PacifiCorp's bidirectional scheduling rights upon commencement of the PTP service (as noted, this amendment reflects the conversion to the PTP service). PacifiCorp is required to file the amendment to the legacy agreement with the Commission for approval. Finally, BPA would execute a construction and coordination agreement with PacifiCorp which sets forth PacifiCorp's obligations to design, coordinate with BPA, and install at its sole expense the Meridian Series Capacitor Project.

Following the February 8, 2022 workshop, several stakeholders asked how the proposed PacifiCorp transmission service would affect the constrained transmission system in central Oregon. Customers also asked whether BPA was considering additional upgrades in central Oregon as part of the B2H negotiations and, if so, whether there was an opportunity for BPA's customers to share the costs and benefits for those upgrades. As BPA explained in its April 1, 2022, response to the workshop comments, the conversion paired with the redirected service does not affect the transmission service BPA provides to other customers in central Oregon. As described above, BPA evaluated the service consistent with its business practices which take into account existing obligations and higher queued requests. Further, the 2021 joint study undertaken by BPA, PacifiCorp, and Idaho Power identified the Midline and Meridian Series Capacitor Projects as upgrades that would improve system performance with B2H in service. However, these projects and the B2H project do not increase the capacity available to BPA's other customers in central Oregon.

2. BPA providing PTP Service to Idaho Power

The 2022 Letter explained that, in lieu of a previously considered asset exchange between BPA and Idaho Power under the B2H with Asset Swap proposal, Idaho Power would acquire 500 MW

of PTP service from BPA for delivery of northwest resources to the B2H connection at the proposed BPA Longhorn substation. Before execution of the Term Sheet, Idaho Power submitted a transmission request seeking this service. BPA evaluated the request as part of the 2021 TSEP Cluster Study. Following the study, BPA determined that the request could be accommodated with stipulations. The stipulations include the energization of the B2H project and the interconnection of the B2H project to the proposed BPA Longhorn substation (see subsection 3 for discussion about the proposed B2H interconnection). Idaho Power would pay for the PTP service pursuant to BPA's OATT and posted transmission rates. BPA is proposing to execute the PTP agreement with conditions precedent reflecting these stipulations concurrent with the issuance of the final decision in the Closeout letter.

3. B2H Interconnection to the Proposed BPA Longhorn Substation

The northern terminus for the B2H project and the point of interconnection with BPA's system would be BPA's proposed Longhorn substation near Boardman, Oregon. The 2022 Letter explained that to facilitate the B2H interconnection at the proposed BPA Longhorn substation, BPA, Idaho Power, and PacifiCorp would develop line and load interconnection and related funding and construction agreements. In February of 2022, Idaho Power as project manager for the B2H project, submitted a line and load interconnection request (L0515) for the B2H interconnection. BPA is currently studying this request, which will include environmental review, and intends to offer additional agreements and make decisions on design, advance funding, and construction in accordance with BPA's line and load interconnection business practice.

BPA is not making a final decision to construct the proposed Longhorn substation as part of B2H with Transfer Service decision. Prior to Idaho Power's B2H interconnection request L0515, Umatilla Electric Cooperative ("UEC") submitted a load interconnection request (L0482) ("UEC project") and the construction of the proposed Longhorn substation has been identified as a need for the UEC project. At this time, the UEC project is further along in the study process than the proposed B2H interconnection. BPA has completed the technical studies for the UEC request and is currently in the process of completing environmental review of the potential impacts to the human and natural environments (*e.g.*., physical, biological, and cultural resources) under NEPA. The NEPA documentation for the UEC interconnection request will be made available to the public on BPA's website. After BPA completes the environmental studies, which is expected in February, 2023, BPA will make a final decision about the construction of the Longhorn substation in response to the UEC interconnection request. Accordingly, BPA's decision to construct the proposed Longhorn substation would be in response to the UEC request and would not be driven by the final decision for the B2H with Transfer Service plan of service.

While BPA's final decision to construct the Longhorn substation will be in response to the UEC request and not the B2H with Transfer Service plan of service, BPA would design the proposed Longhorn substation to accommodate the B2H interconnection request and other future interconnection requests. Equipment specific to the UEC project and the B2H interconnection request, such as an additional 500 kV terminal for the proposed B2H interconnection, 500/230 kV transformers, and a 230 kV yard for the UEC project, would be designed, funded, and developed in accordance with BPA's line and load interconnection business practice. BPA

anticipates allocating advance funding responsibilities between the UEC project and the B2H interconnection in accordance with BPA's line and load interconnection business practices. Consistent with the Term Sheet in recognition of the benefits exchanged, BPA would require advance funding from the B2H project, subject to repayment through transmission credits on OATT service, for costs associated with the B2H interconnection at the proposed BPA Longhorn substation.

4. Removal of a segment of BPA's Boardman-to-Ione transmission line

A portion of BPA's Boardman-to-Ione 69-kV transmission line is located in a right-of-way crossing the U.S Navy's ("Navy") Naval Weapons Systems Training Facility Boardman Property in Umatilla County, Oregon. BPA uses this line to serve Columbia Basin Electric Cooperative, Inc. ("Columbia Basin"). Idaho Power and PacifiCorp need a segment of this right-of-way for B2H construction. For B2H to be constructed on the right-of-way, BPA's Boardman-Ione transmission line must be removed first. Additionally, BPA would need to find an alternative to serve Columbia Basin.

In 2019, BPA decided to enter into an amended Boardman-to-Ione transmission line land use agreement with the Navy to allow for the removal of the line from the Navy property so that the B2H project could repurpose a segment of the right-of-way, with the remaining segment to be removed to the benefit of cultural and natural resources in the area. See Bonneville Power Administration, Record of Decision, Boardman-to-Ione 69kV Transmission Line (May 13, 2019), *available at* https://www.bpa.gov/-/media/Aep/efw/nepa/active/boardman-to-hemingway/board-ione-lua-nepa-rod-05-13-2019-final.pdf. BPA's decision was contingent on multiple considerations, including BPA entering an agreement with Idaho Power and PacifiCorp to ensure that BPA would be reimbursed in full for all costs associated with removing the Boardman-to-Ione line and providing an alternative to service Columbia Basin's load. In the event the B2H project is not constructed, BPA will retain its right-of-way on the Navy property.

On March 18, 2020, BPA, Idaho Power, and PacifiCorp executed an agreement for PacifiCorp and Idaho Power to pay or reimburse BPA for its costs associated with removing and replacing the Boardman-to-Ione line if the B2H project is constructed. BPA's costs include providing replacement service for Columbia Basin's loads, which would include studies and design, environmental review, building a step down substation, tap line and tap, and other necessary construction or reconfigurations to accommodate the removal. These reimbursement commitments were acknowledged in the section of the Term Sheet describing Idaho Power and PacifiCorp's intent for the B2H construction funding agreement. The commitments have also been incorporated into agreements with Idaho Power, as project manager for B2H, associated with BPA's removal and replacement of the Boardman-to-Ione line.

With regard to BPA finding an alternative to serve Columbia Basin, BPA intends to request transmission service from UEC to serve Columbia Basin's load. As an initial step, BPA has submitted a line interconnection request to UEC. This request starts the process for BPA to construct a new step down substation and transmission facilities to connect the UEC end point of service to Columbia Basin's system. At this time, BPA is siting, designing, and studying these proposed facilities. As planning progresses, BPA would conduct environmental review of the

potential impacts to the human and natural environments that could be expected from implementing the Boardman-to-Ione line relocation. As noted above, pursuant to the March 18, 2020, agreement, BPA will recover costs associated with the Boardman-to-Ione line relocation from PacifiCorp and Idaho Power. Energization of the proposed alternative service would need to be completed by spring of 2025, to allow time to remove the old line and build the new B2H line by spring of 2026.

5. Operational agreement with Idaho Power and PacifiCorp

The 2022 Letter described BPA, Idaho Power, and PacifiCorp's intent to develop an operational agreement covering various facilities and agreements that affect Path 14 (Idaho to Northwest, the WECC transmission path that will include B2H), Path 75 (Hemingway-Summer Lake 500kV), and the Northwest AC Intertie. Following execution of the Term Sheet, BPA, PacifiCorp, and Idaho Power prioritized negotiation of the contracts described above. Negotiation of the operational agreement will begin this winter.

C. Assignment Agreement with PacifiCorp

The 2022 Letter explained that BPA currently purchases 200 MW of conditional firm PTP service from Idaho Power to wheel power over Idaho Power's system for ultimate delivery to SILS customers on PacifiCorp's system. With the construction of the B2H project, the NITSAs, and associated asset exchanges between Idaho Power and PacifiCorp, BPA will no longer need to procure these conditional firm PTP services. The 2022 Letter described BPA's intent to assign its conditional firm PTP service agreements on Idaho Power's system to PacifiCorp, subject to certain stipulations. Prior to the assignment, BPA would submit redirect requests to the points of receipt and points of delivery selected by PacifiCorp. PacifiCorp would be responsible for all costs associated with the redirect and assignment. This redirect and assignment is to PacifiCorp's benefit for the B2H deal, but would not result in any increased costs to BPA.

Following execution of the Term Sheet, BPA and PacifiCorp negotiated a Letter Agreement setting out the terms for the future redirect and assignment of BPA's conditional firm PTP service. BPA is proposing to execute the Letter Agreement concurrent with issuing the final decision in the Closeout Letter. Pursuant to the Letter Agreement, BPA would submit redirect requests pursuant to Idaho Power's OATT for the two conditional firm service agreements on Idaho Power's system. BPA would request the redirected service to commence following the energization of B2H and commencement of BPA's NITSAs with Idaho Power. PacifiCorp would reimburse BPA for all study costs and fees assessed by Idaho Power.

Following Idaho Power's evaluation of the redirect requests, PacifiCorp would determine if the redirected service, including any conditions Idaho Power might assess, is acceptable to PacifiCorp. If the service is acceptable to PacifiCorp, then BPA would confirm the requests and assign the redirected reservations to PacifiCorp. If PacifiCorp determined that the redirected service was not acceptable, then BPA would withdraw the requests and, if directed by PacifiCorp, submit alternative redirect requests. If B2H is energized and BPA's NITSAs have commenced but PacifiCorp has not yet accepted assignment of the conditional firm PTP service agreements, PacifiCorp would reimburse BPA for all rates and charges that Idaho Power assesses to BPA for the two 100 MW conditional firm PTP service agreements, until such time as the service is assigned to or waived by PacifiCorp.

III. Business Case for the B2H with Transfer Service Plan of Service

The 2022 Letter described BPA's business case for the B2H with Transfer Service plan of service at a high level, noting that the proposal would provide a firm, stable, and long-term transmission path to deliver resources from the BPA transmission system to the SILS customers' loads at an economical cost. During the February 8, 2022, workshop, BPA explained that the estimated benefits of B2H with Transfer Service is a 35% to 52% improvement in net present value ("NPV") over the interim plan of service. Now that contract negotiations are complete, BPA has updated the assumptions in the business case. This letter provides an overview of BPA's business case.

Quantitatively, BPA analyzed the costs associated with the B2H with Transfer Service plan of service and the current interim plan of service using a NPV methodology over a 30-year horizon and with a discount rate of 2.81%. Notably, there are significant uncertainties associated with the assumptions used for a 30-year period. Therefore, BPA evaluated numerous rate, cost, and revenue assumptions to determine a range of cost savings that could be expected over a 30-year period. On average over 30 years, the B2H with Transfer Service plan of service yields an estimated cost of around $520 million. Over that same time period, the continuation of the current interim plan of service yields an estimated cost of around $1.24 billion. Accordingly, the B2H with Transfer Service provides an estimated $720 million of cost savings as compared to the interim plan of service.

Each of the scenarios evaluated in the business case includes significant complexity, with many factors driving cost, savings, and relative value. However four primary drivers account for the majority of the significant financial benefit associated with the B2H with Transfer Service plan of service over the current interim plan of service. First, the B2H with Transfer Service plan of service eliminates the need to acquire two legs of transmission that BPA currently uses to serve the SILS customers' loads. Eliminating one leg of transmission yields an expected value of approximately $250 million in cost savings over the 30-year period.

Second, Idaho Power is expected to have lower rates for NITS as compared to PacifiCorp's rates for NITS under the interim plan of service. As such, taking NITS from Idaho Power is expected to have a lower cost compared to the PacifiCorp NITS costs BPA anticipates if BPA were to continue the current interim plan of service. BPA's analysis of Idaho Power's expected rates took into account projected increases following its construction of B2H, as well as the implications of such rate increases on BPA's costs under the existing NITSAs for service to

BPA's other preference customers in southern Idaho. The NITS service from Idaho Power is expected to yield approximately $190 million in cost savings over the 30-year period.

Third, BPA expects $45 million in lower overall Energy Costs over the 30-year period by reducing BPA's reliance on market power in the vicinity of the SILS customers.

Lastly, the B2H with Transfer Service plan of service yields incremental revenue for BPA associated with 500 MW of PTP service that BPA would provide to Idaho Power. This PTP service is estimated to yield an expected value of approximately $200 million in revenue over a 30-year period.

BPA also expects $40 million in the recovery of sunk cost (the sunk cost is the Purchase Price for the sale of BPA's permitting interest, which includes the payment of the $30 million BPA incurred towards permitting plus the $10 million security). BPA anticipates the costs associated with purchasing transmission service from UEC to serve Columbia Basin's load to be modest.

In addition to these quantitative financial benefits, BPA expects other substantial benefits. As noted above, BPA's current interim plan of service relies on a leg of transmission over Idaho Power's system that is "conditional firm" PTP service. Conditional firm PTP service is a type of transmission service that can be curtailed more readily under certain system conditions. The conditions associated with this service are reviewable by Idaho Power every two years, increasing the risk of additional conditions for curtailment of BPA's PTP service over time. With Idaho Power's construction of B2H, BPA would receive long-term firm network transmission to serve its southeast Idaho loads. Network transmission is redispatched rather than curtailed like PTP, substantially reducing BPA's risk of service to its loads.

Additionally, the increase in transmission capacity across Idaho Power's system from the construction of B2H would enhance BPA's ability to serve its other existing preference customers currently served by NITSAs over Idaho Power's transmission system. BPA uses these existing NITSAs to serve 13 preference customers in the Burley, Idaho area, Oregon Trail Electric Cooperative in eastern Oregon, and the City of Weiser in western Idaho. BPA also uses an existing NITSA to deliver reserve power from the federal system to the United States Bureau of Reclamation and irrigation customers. The completion of the B2H project would create capacity on Idaho Power's system that could be used to serve the load growth of these existing customers. Accordingly, potential transmission system congestion on federal power deliveries to these customers over Idaho Power's system would be alleviated.

The B2H with Transfer Service plan of service also reduces BPA's reliance on market power in the vicinity of the SILS customers. The current interim plan of service has BPA sourcing market power from the desert Southwest, which carries with it resource adequacy considerations and negative implications for the carbon content of BPA's fuel mix. Reduced market reliance alleviates these negative effects and generally reduces BPA's cost risk in a region where resource retirements loom and BPA has already observed reduced liquidity.

Additionally, while providing PacifiCorp with PTP service in central Oregon would not result in additional revenues for BPA because it reflects the redirect of existing PTP service that

PacifiCorp currently pays for, that aspect of the B2H with Transfer Service arrangement works to achieve BPA's strategic objectives of converting legacy service to standard OATT service. Idaho Power and PacifiCorp would also fund the series capacitor projects that improve system performance when B2H is in service. Lastly, the B2H with Transfer Service plan of service avoids the complexities and complications of joint ownership and asset swaps originally considered in the B2H with Asset Swap proposal (a description of the B2H with Asset Swap proposal was provided in the 2022 Letter).

IV. Public Process and Next Steps

BPA is proposing to proceed with the B2H with Transfer Service plan of service and execute binding contracts with Idaho Power and PacifiCorp. Public participation and input on the B2H with Transfer Service plan of service is important to BPA. Before BPA makes a final decision, BPA is seeking public comment through February 9, 2023. Comments should be submitted here. BPA will hold a workshop to answer questions about the B2H with Transfer Service plan of service on January 23, 2023. Please find details of that workshop here. BPA is also conducting appropriate NEPA processes. If BPA decides to proceed, BPA will issue a Closeout letter to the region on or about March 23, 2023, describing its reasoning and responding to comments.

If BPA's final decision is to proceed, BPA would execute the Purchase, Sale, and Security Agreement, the two NITSAs with Idaho Power, the PTP agreements and other related transmission agreements with PacifiCorp and Idaho Power, and the Letter Agreement with PacifiCorp concurrent with issuing the Closeout letter to the region. The decision to execute agreements associated with the proposed B2H interconnection to the BPA Longhorn substation and the removal and replacement of BPA's Boardman-to-Ione transmission line would be in accordance with BPA's line and load interconnection processes.

Idaho Power/503
Witness: Jared L. Ellsworth

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

Docket PCN 5

In the Matter of

IDAHO POWER COMPANY'S
PETITION FOR CERTIFICATE OF PUBLIC CONVENIENCE
AND NECESSITY

BPA B2H Workshop Presentation
(Jan. 23, 2023)

February 21, 2023



B2H Workshop

January 23, 2023

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Welcome to the Boardman to Hemingway (B2H) w/ Transfer Service Workshop - *The meeting will begin momentarily*

- When joining the Event, enter your name and email address where indicated so your name is visible in the Participant window to the meeting host
- Use the "Call Me using phone" (recommended) or "Use computer audio" for your Audio connection to the meeting
- Once in the meeting, open both the Participant and Chat windows for interacting with panelist and seeing your meeting status

Meeting Participation and How to Ask Questions:

- After you join the WebEx Event, you will not be able to unmute yourself or share your video/webcam unless the presenter makes you a panelist.
- **To be recognized for asking a question:**
  1. *Use the Chat option to send a question request to "Everyone"*
  2. *Or use the "Raise your Hand" option to signal you have a question*



- The Host/Panelists will monitor these actions and unmute or move you to "Panelist Status" and then call on you to ask a question.
- When finished the Host will re-mute or move you back to Attendee status. Please remember to re-mute and lower your hand when done speaking.

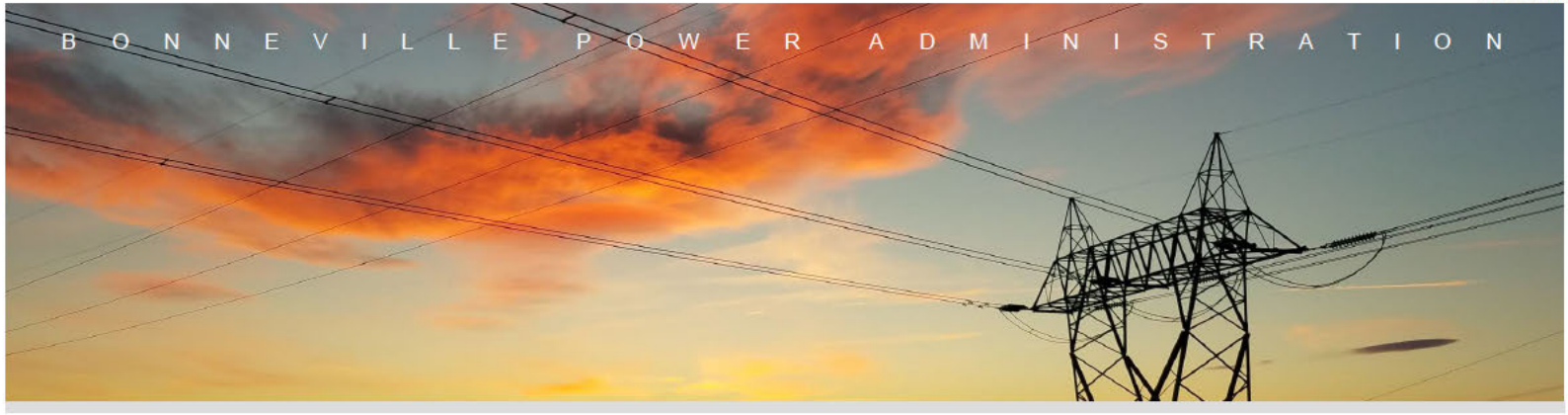
B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Agenda

- Executive Overview
- Background and Context
- Business Case
- Final Terms and Agreements
  - Arrangements to effectuate long-term firm transfer service for SILS customers' loads
  - Transmission arrangements for PacifiCorp and Idaho Power
- Next Steps
- Q & A

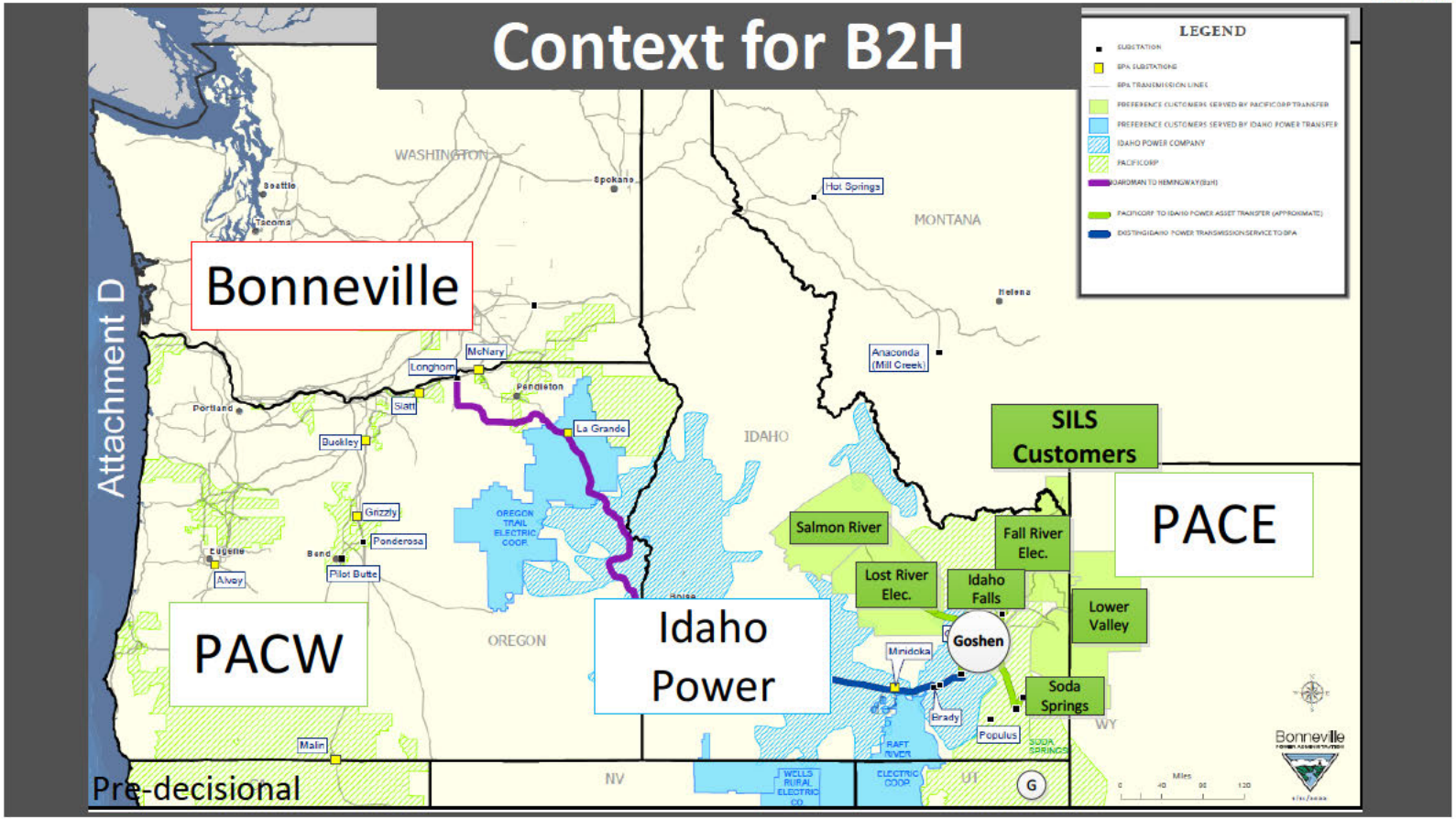
Executive Overview

- Contract negotiation for B2H with Transfer Service have concluded and BPA is proposing to execute these contracts
  - Contracts reflect terms in the non-binding Term Sheet
- Key Benefits:
  - Eliminates reliance on conditional firm PTP for transfer service to SILS customers
  - Financial benefits of having a single wheel of transfer service
  - Migration of SILS customer loads to simplified, durable and reliable firm network transmission service
  - Congestion relief that benefits BPA's deliveries for all Southern and Southeast Idaho customers
  - Eliminating today's interim service reliance on market purchases
  - Incremental revenues from new PTP sales over BPA's system

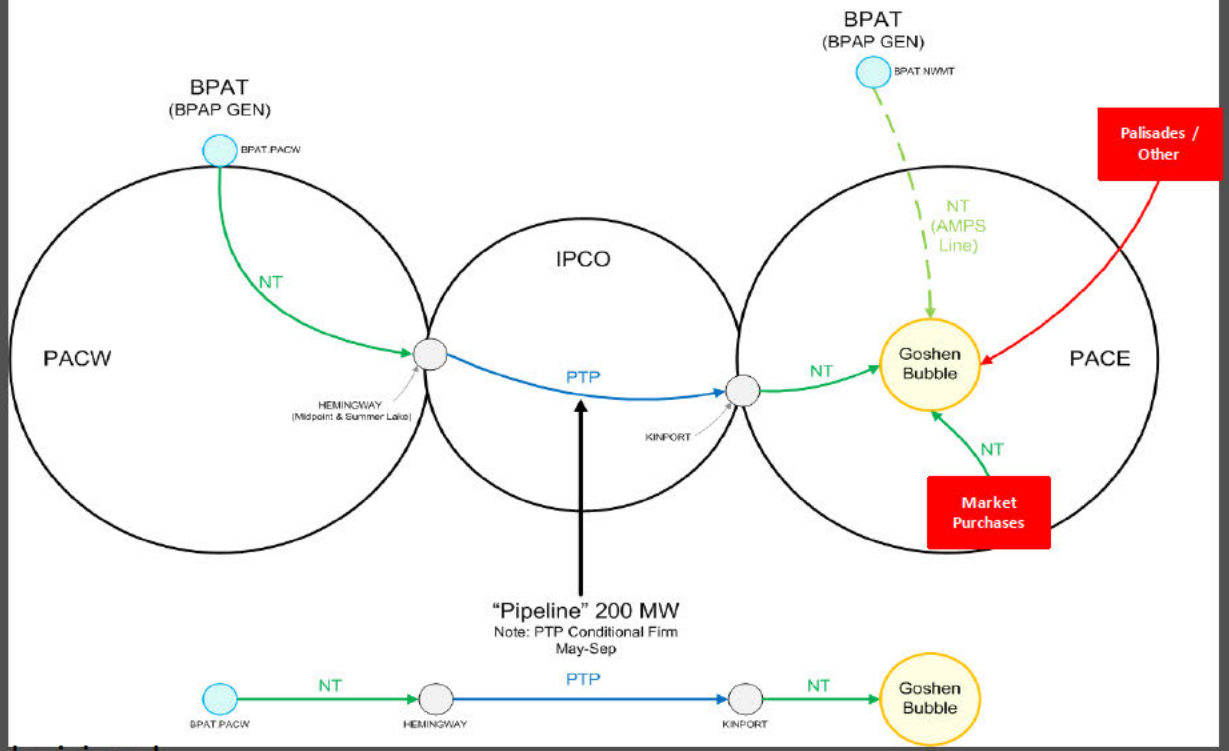


Background and Context

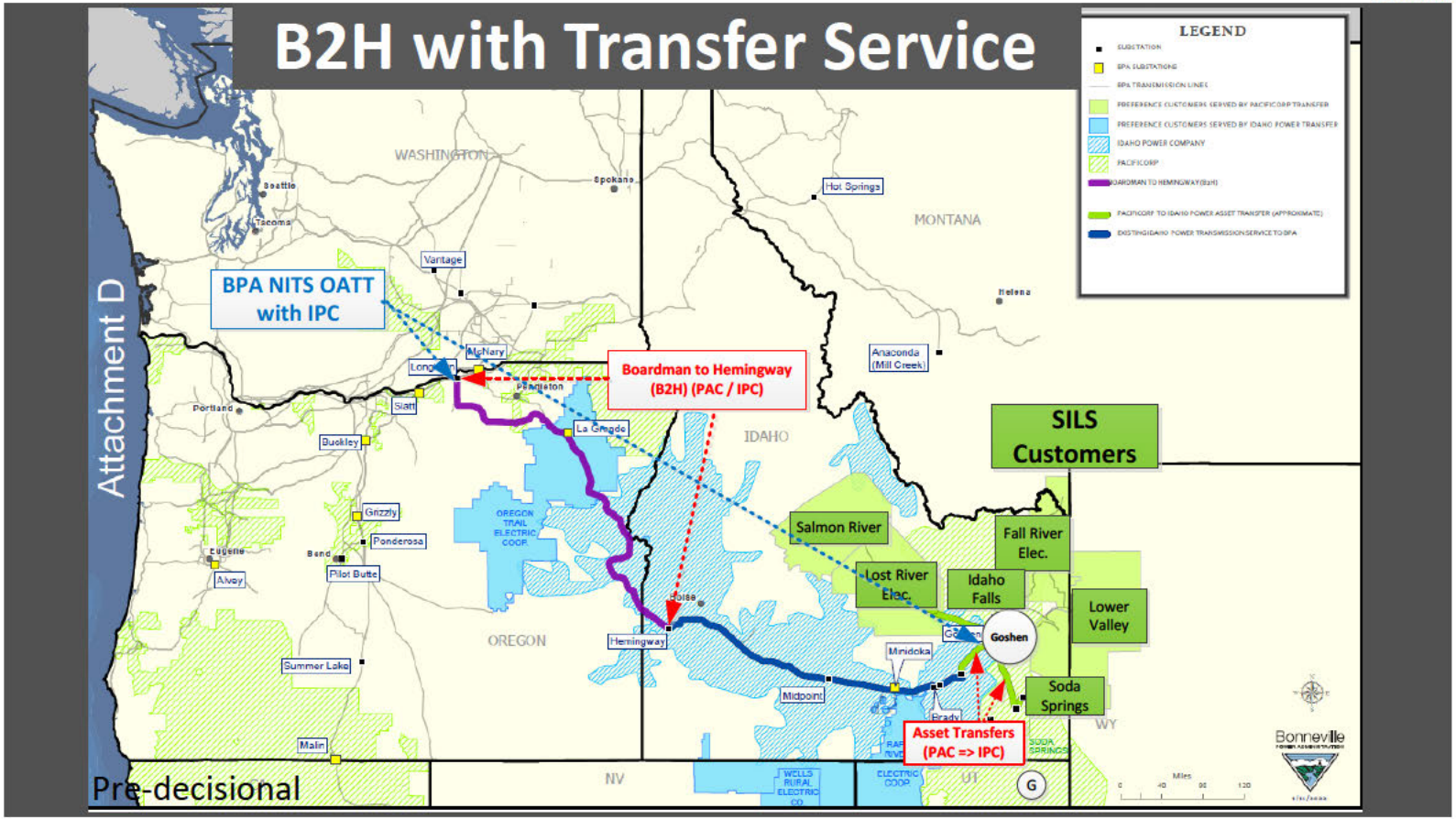
Pre-decisional

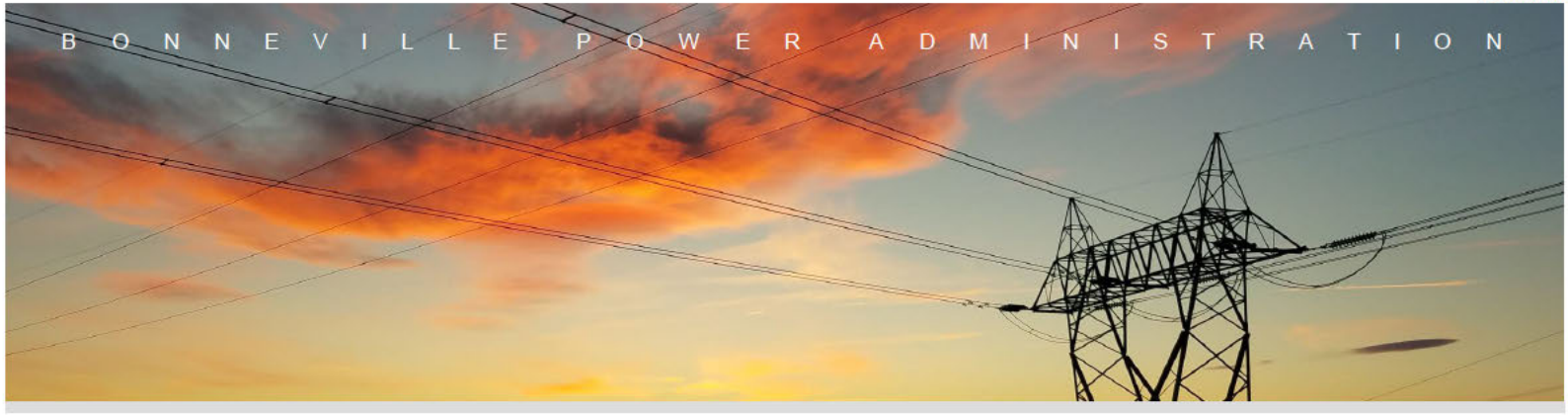

Context for B2H
Attachment D
Bonneville
PACW
Idaho Power
PACE
SILS Customers
Salmon River
Lost River Elec.
Fall River Elec.
Idaho Falls
Lower Valley
Goshen
Soda Springs
Pre-decisional
LEGEND
WASHINGTON
OREGON
IDAHO
MONTANA
WY
NV
UT
Seattle
Tacoma
Spokane
Hot Springs
Helena
Anaconda (Mill Creek)
McNary
Longhorn
Pendleton
Portland
Slatt
La Grande
Buckley
Grizzly
Ponderosa
Eugene
Bend
Alvey
Pilot Butte
Boise
Minidoka
Brady
Populus
Malin
OREGON TRAIL ELECTRIC COOP
WELLS RURAL ELECTRIC CO
RAFT RIVER ELECTRIC COOP
SODA SPRINGS
G

Current Load Service



Pre-decisional


B2H with Transfer Service
LEGEND
BPA NITS OATT with IPC
Boardman to Hemingway (B2H) (PAC / IPC)
SILS Customers
Salmon River
Fall River Elec.
Lost River Elec.
Idaho Falls
Lower Valley
Goshen
Soda Springs
Asset Transfers (PAC => IPC)
Hemingway
Midpoint
Minidoka
Brady
Summer Lake
Malin
Grizzly
Ponderosa
Pilot Butte
Alvey
Buckley
Slatt
McNary
Vantage
La Grande
Anaconda (Mill Creek)
Hot Springs
Helena
Spokane
Seattle
Tacoma
Portland
Eugene
Bend
Boise
WASHINGTON
OREGON
IDAHO
MONTANA
WY
NV
UT
Attachment D
Pre-decisional



Business Case

Pre-decisional

Business Case

- Over 30 year period:
  - Interim plan of service (current state): $1.24B
  - B2H with Transfer Service: $520M
  - Gross Savings $720M
- Primary Quantitative Cost Factors:
  - Lower transmission costs from IPC from removing an additional wheel across Idaho Power
  - Reduced energy cost by reduced reliance on market purchases
  - Recovery of sunk costs
  - Incremental transmission revenue
- Additional Qualitative Benefits:
  - NITS service on firm transmission with redispatch compared to PTP CF which is non-firm for a period of the year
  - Additional capacity on IPC's system enhances ability to serve existing preference customers on IPC's system
  - Reduced reliance on market purchases for SILS customers
  - Conversion of legacy rights to OATT

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Business Case – Status Quo PV

Cost Summary	Present Value Cost
($ in Millions)	
Energy Costs, net	(46.4)
PAC Transmission Costs	(681.2)
IPC PTP Costs	(281.8)
IPC NT Costs	(230.7)
IPC NEPA/Pre-Construction Sunk Cost Recovery	0
Sales Revenue (Longhorn to Mid-C w/ IPC)	0
Total Cost	**(1,240.1)**

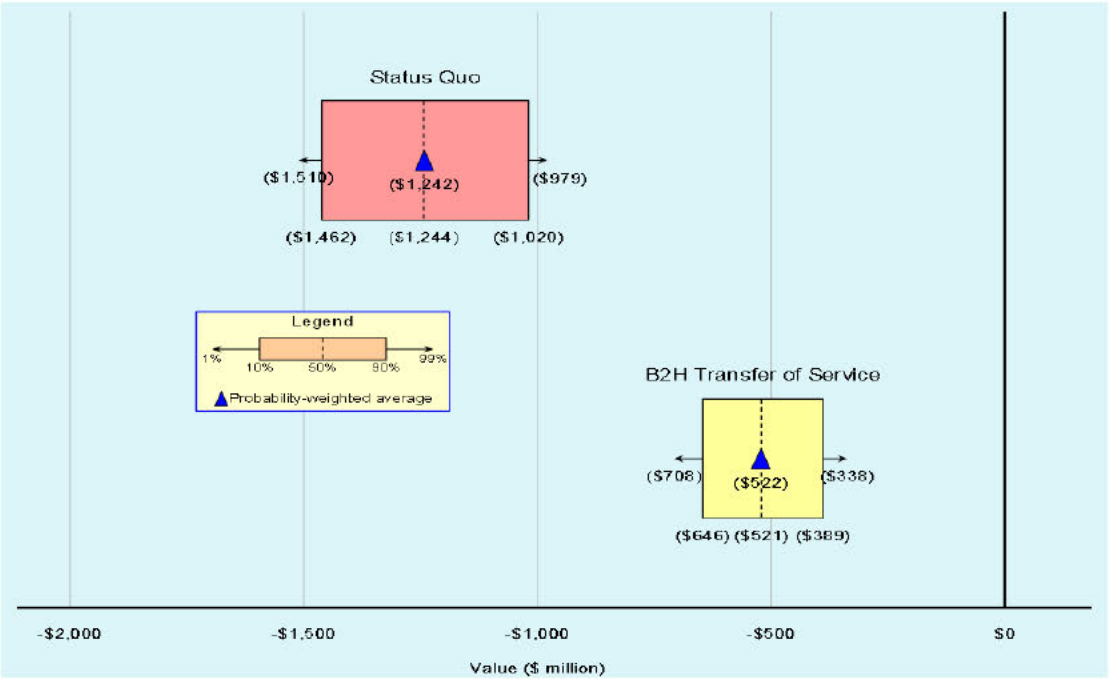
B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Business Case – B2H with Transfer Service PV

Cost Summary	Present Value Cost
($ in Millions)	
Energy Costs, net	(0.9)
PAC Transmission Costs	(61.0)
IPC PTP Costs	(30.3)
IPC NT Costs	(654.8)
IPC NEPA/Pre-Construction Sunk Cost Recovery	34.9
Sales Revenue (Longhorn to Mid-C w/ IPC)	193.5
Total Cost	**(518.6)**

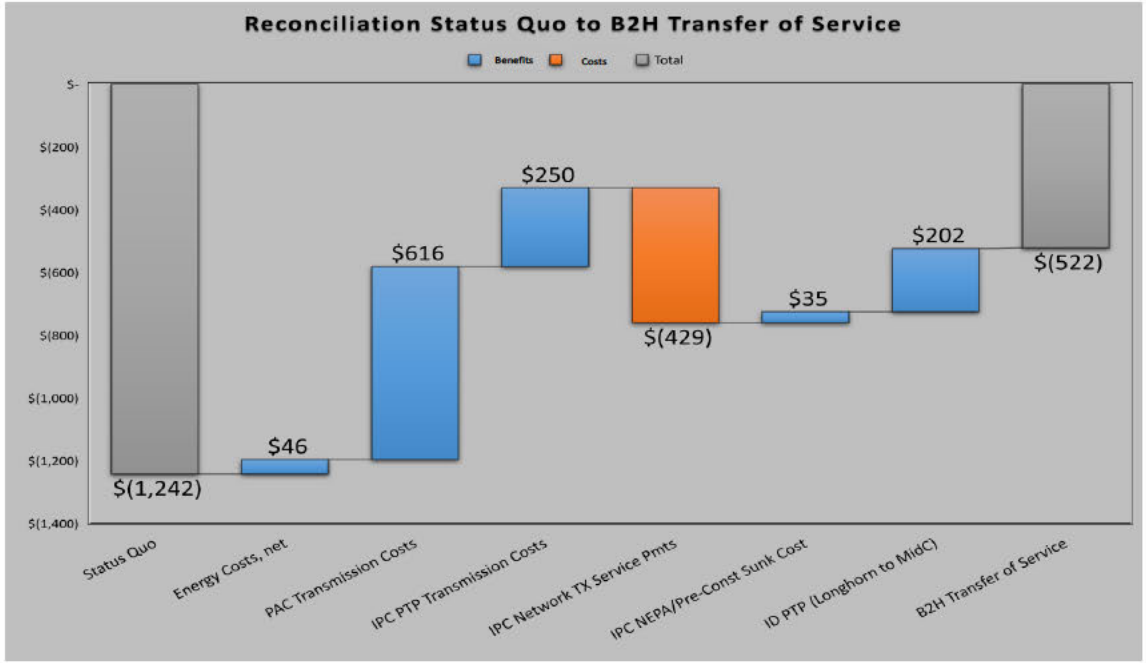
B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Business Case – PV Summary



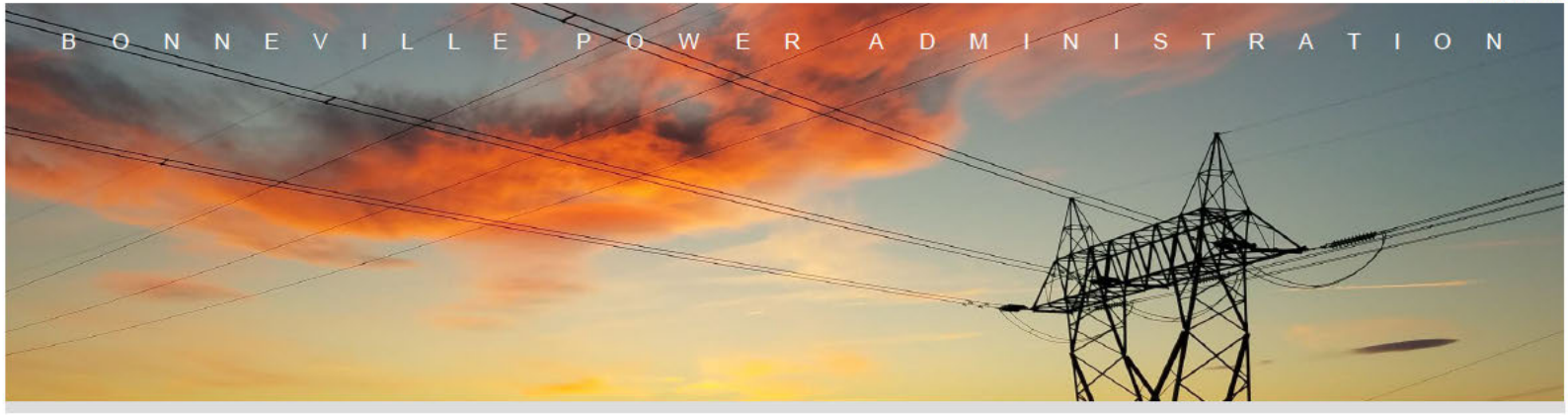
B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Business Case – PV Crosswalk



Business Case – Key Assumptions

- Period of analysis 30 years (Benefits) plus construction period (2023 through 2027)
- Discount Rate: 2.81% (BPA weighted average cost of debt)
- BPA Southern Idaho Load Forecast
- BPA Energy Price Forecast for Mid-C and Mona (Palo Verde)
- Contract energy purchases to firm up energy delivery renewed in July 2022 for another 5 year term. Assume renewal every 5 years in Status Quo – continued transfer service
- Sale of Transmission service to IPC
  - IPC purchase of 500 MW of PTP for 5 years after energization, with reduced sales following
- Rate Assumptions (escalations based on 10 years of historic increases)
  - BPA – Current Rates (BP-22) escalated at 2.21% (PTP Service)
  - IPC Current PTP Rate escalated at 3.41%
  - IPC Network Rate (Revenue Requirement) escalated at 3.3%, plus IPC share of B2H investment (45%)
  - PAC Network Rate – current escalated at 3.22%



Final Terms and Agreements

Pre-decisional

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Purchase, Sale, and Security Agreement

- BPA would transfer its permitting interest share to Idaho Power in exchange for payment to BPA for the costs BPA incurred towards permitting the B2H project
- BPA would also pay Idaho Power the $10 million security payment. Idaho Power would return the $10 million security to BPA within 60 days of energization of the B2H project
- The remaining amount of the Purchase Price would be paid in installments based on a 20 year payment schedule, beginning 10 years after B2H is energized, provided that loads reach required level

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

NITS Agreements with Idaho Power

- 2 New NITSAs:
  - NITSA to provide service to the Goshen area customers (Lower Valley, Soda Springs, Fall River, Lost River, and Salmon River) (“Goshen NITSA”)
  - NITSA to provide service for Idaho Falls (“Idaho Falls NITSA”)
  - Service under the NITSAs would commence upon energization of B2H. Service would terminate on July 1, 2046, and could be rolled over for additional terms

Existing NITSA with Idaho Power

- BPA has three existing NITSA with Idaho Power serving 15 Preference customers and Reserve Power Customers (USBR irrigation load)
- Idaho has identified transmission constraints serving these load from our current designated network resources
- BPA will add new Points of Receipt in these 3 NITSA once B2H is energized

Wells Rural Elec
Albion
Burley, City of
Declo, City of
East End Mutual
Farmers Electric
Heyburn, City of
Minidoka, City of
Oregon Trail
Riverside Electric
Rupert, City of
South Side Electric
Raft River REC
United Electric Co-op, Inc.
Weiser, City of

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Assignment Agreement with PacifiCorp

- BPA has 200 MWs of PTP CF from Idaho Power
  - Won't be needed with B2H with Transfer Service
- BPA would submit redirect requests and assign its two 100 MW PTP CF agreements to PacifiCorp after B2H energization
- The redirect and assignments for PacifiCorp would be at no cost to BPA. PacifiCorp would reimburse BPA for all costs BPA incurs

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

BPA providing PTP service to PacifiCorp

- BPA would provide PacifiCorp with 680 MW PTP service at/near the Ponderosa substation, which includes:
  - Conversion of PacifiCorp legacy scheduling rights over BPA's Buckley-Summer Lake line to PTP service paired with the redirect of PacifiCorp's existing PTP service
  - PacifiCorp will pay for the PTP service pursuant to BPA's posted transmission rates
- Service would commence after the following conditions precedent are satisfied:
  - The B2H Project, which includes series compensation at the midpoint of the line, is energized
  - PacifiCorp transferring its Goshen assets to Idaho Power w/ BPA taking NITS from Idaho Power
  - PacifiCorp increases the series compensation at the Meridian substation
- Evaluation of the PTP service was consistent with BPA's Tariff and business practices
  - PacifiCorp submitted transmission service requests last spring
  - BPA's evaluation took into account existing obligations and higher queued requests
  - BPA's evaluation concluded that conversion paired with redirected service does not affect transmission service BPA provides to other customers in central Oregon

BPA providing PTP service to Idaho Power

- BPA would provide Idaho Power with 500 MW of PTP service for delivery of northwest resources to the B2H interconnection at the proposed Longhorn substation
- TSR submitted prior to the execution of the Term Sheet
- Evaluated as part of the 2021 TSEP Cluster Study
  - Request could be accommodated after energization of B2H and the proposed B2H interconnection at Longhorn
- Idaho Power to pay for the PTP service pursuant to BPA's posted transmission rates

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

B2H Interconnection to the proposed BPA Longhorn Substation

- BPA is studying the line and load interconnection request to interconnect the B2H project to the proposed BPA Longhorn substation
- BPA's decision to build Longhorn is not being made as part of this B2H with Transfer Service decision
  - BPA's decision on building Longhorn substation will be made in response to Umatilla's interconnection request, which predated Idaho Power's B2H interconnection request
  - Technical studies for the Umatilla interconnection request are complete and environmental review is in process (expected completion February 2023)
- Design of Longhorn substation would accommodate the B2H interconnection request and future interconnections
- Equipment specific to each request would be designed, funded, and developed in accordance with BPA's line and load interconnection practice
  - Allocation of advance funding responsibilities between Umatilla and B2H

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

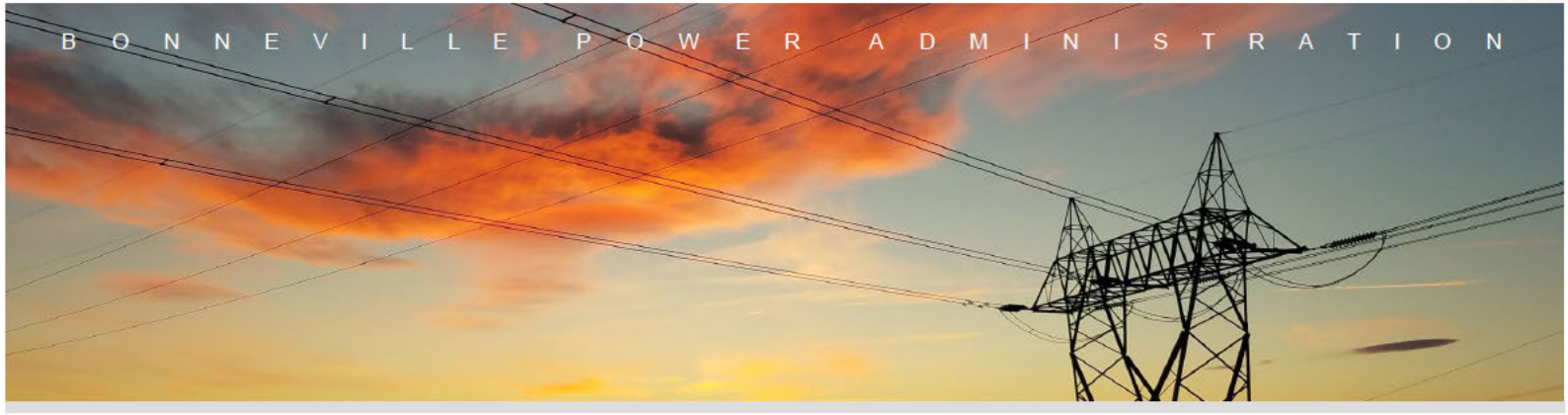
Removal of a segment of BPA's Boardman-to-Ione transmission line

- Transmission path south of Boardman is congested
- BPA's Boardman-Ione 69kV serves Columbia Basin Electric
  - BPA to construct alternative service to Ione south of Navy property
  - Power will come from recently built Umatilla Electric Line
  - BPA will then abandon easement on Navy property
  - B2H to use part of the abandoned path
  - B2H will reimburse BPA for all costs associated with removal/replacement
  - B2H needs access to path by spring 2025 in order to energize B2H spring 2026
  - B2H is currently funding BPA's scoping and transformer procurement



Next Steps

- Comment period is open through February 9, 2023
- Closeout Letter would be issued on or about Mar 23, 2023
  - BPA's final decision
  - Responding to public comments
- If BPA's decision is to proceed with B2H with Transfer Service, then contracts would be executed concurrent with the Closeout Letter



Q & A

Pre-decisional

Idaho Power/504
Witness: Jared L. Ellsworth

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

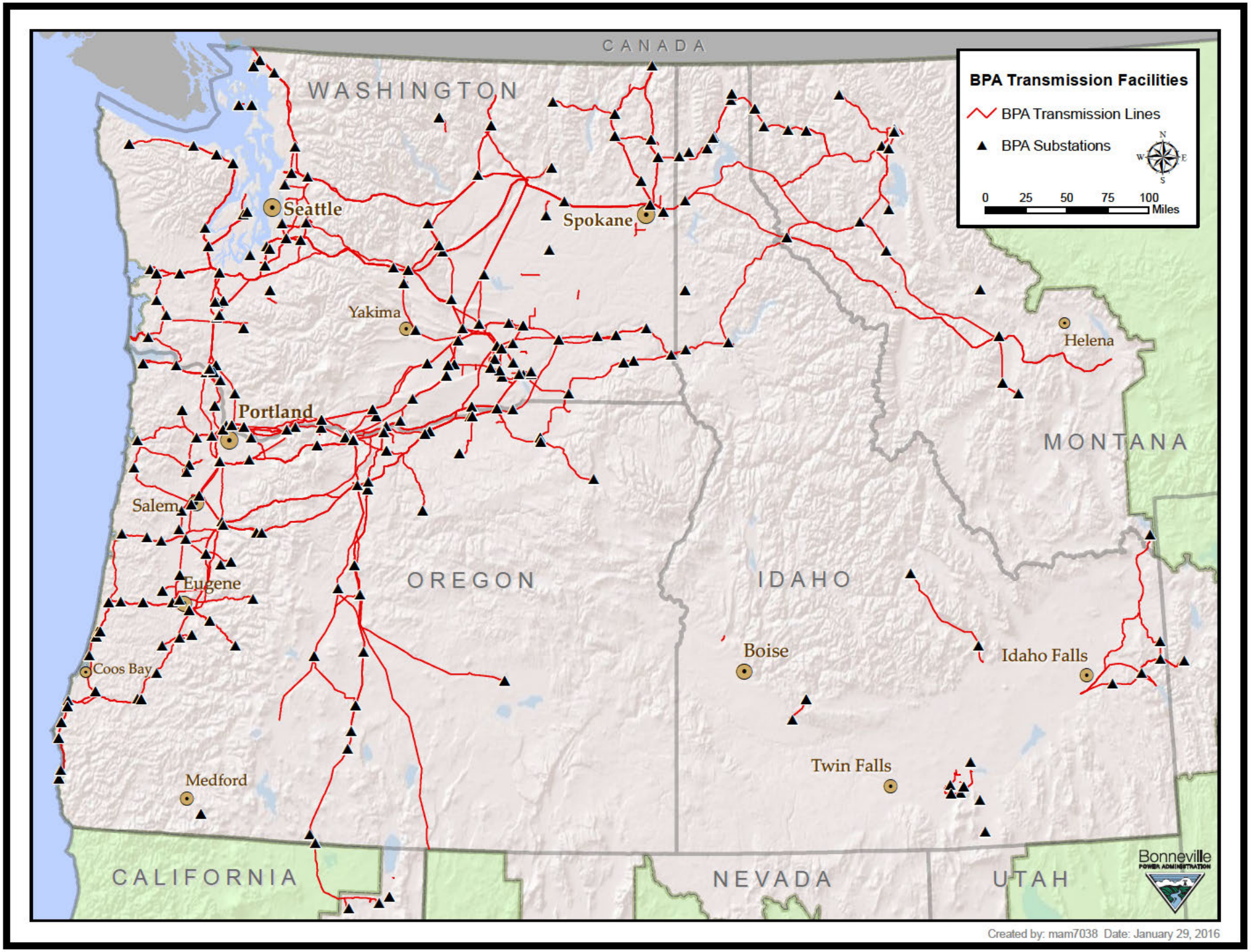
Docket PCN 5

In the Matter of

IDAHO POWER COMPANY'S
PETITION FOR CERTIFICATE OF PUBLIC CONVENIENCE
AND NECESSITY

Maps Identifying BPA Customers and Utility Service Territories

February 21, 2023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Medford
Boise
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Twin Falls
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BPA Transmission Lines
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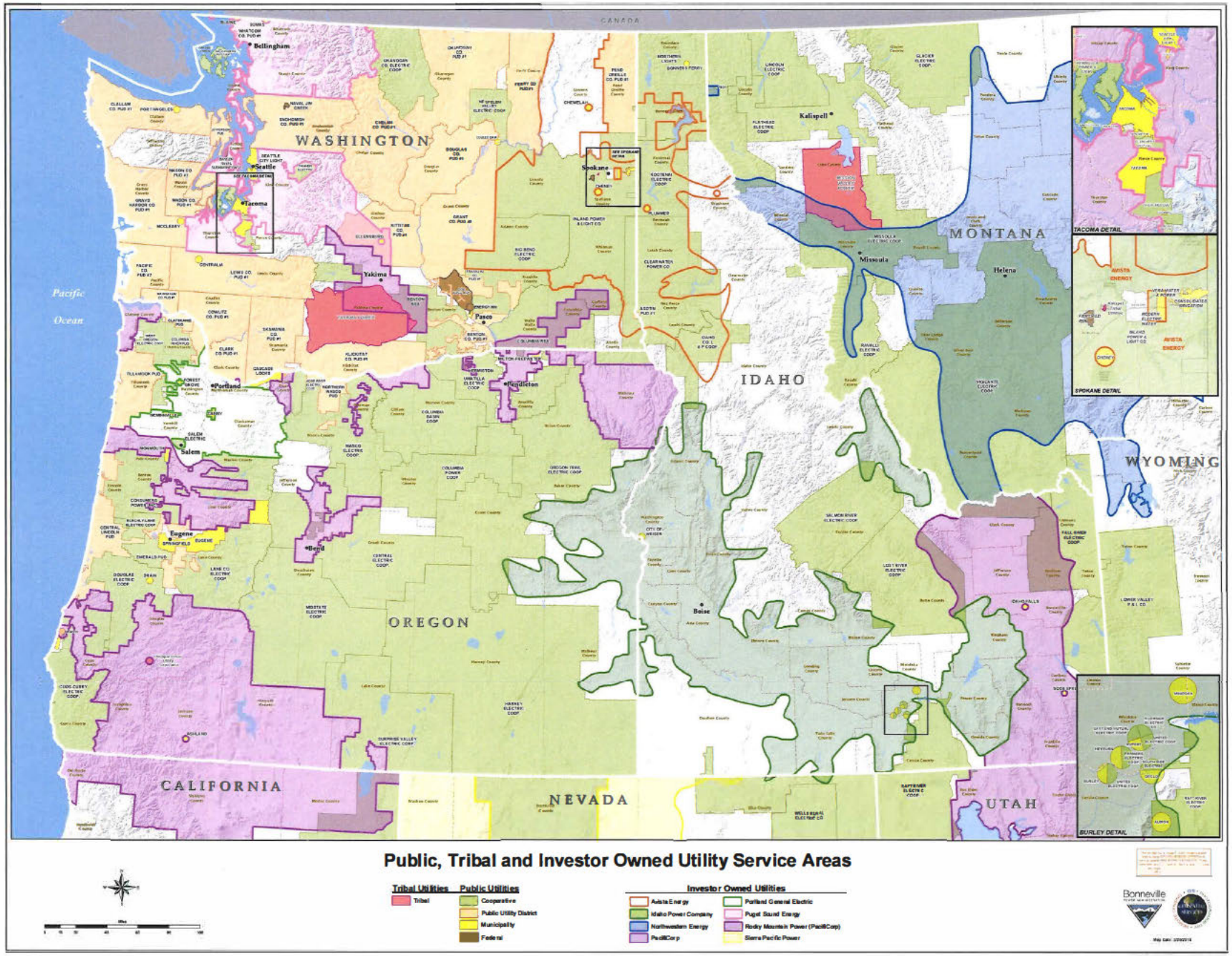
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CALIFORNIA
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IDAHO
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UTAH
Pacific
Ocean
Bellingham
Seattle
Tacoma
Spokane
Kalispell
Missoula
Helena
Yakima
Pasco
Pendleton
Portland
Salem
Eugene
Bend
Boise
TACOMA DETAIL
SPOKANE DETAIL
BURLEY DETAIL
Public, Tribal and Investor Owned Utility Service Areas
Tribal Utilities
Tribal
Public Utilities
Cooperative
Public Utility District
Municipality
Federal
Investor Owned Utilities
Avista Energy
Idaho Power Company
Northwestern Energy
PacifiCorp
Portland General Electric
Puget Sound Energy
Rocky Mountain Power (PacifiCorp)
Sierra Pacific Power
Bonneville

Idaho Power/505
Witness: Jared L. Ellsworth

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

Docket PCN 5

In the Matter of

IDAHO POWER COMPANY'S
PETITION FOR CERTIFICATE OF PUBLIC CONVENIENCE
AND NECESSITY

Comments from BPA Customers and Stakeholders

February 21, 2023

Comments for Southeast Idaho Loads and B2H Transfer Service Proposal

The following comments were submitted in response to the open comment period described below.

BPA is accepting public comments on proposing to execute contracts outlined in a Jan. 9, 2023 Letter to the Region associated with the Boardman to Hemingway with Transfer Service Term Sheet. The proposed plan of service would deliver significant benefits for BPA and its customers, including essential congestion relief and removal of the dependence on conditional firm point-to-point service; consolidation of network integration transmission service from a single transfer service provider for all of BPA's deliveries to southeast and southern Idaho loads; and improved costs compared with today's interim service approach. More information about the Term Sheet and BPA's Southeast Idaho Load Service can be found at Southeast Idaho Load Service - Bonneville Power Administration (bpa.gov). A workshop is scheduled for Jan. 23, 2023 from 1PM-3PM PST to provide additional information on these proposals, updated information is available on the BPA Event Calendar. If you do not see your comment posted two business days after you submit it, please contact (800) 622-4519.

B2HTX23 0001 - Campbell/Raft River Electric

I wish to share my support and the support of the members of Raft River Electric Cooperative (whom I represent as the chairmen of the Board of Directors) for the construction and implementation of the B2H transmission line. As a small rural electric coop in Southern Idaho we have been greatly benefited by our relation ship to BPA. Securing transmission through B2H into southern Idaho will ensure our communities success for years into the future, and help maintain a stable and predictable transmission cost to our members. Please help see B2H become a reality. Thanks John Campbell

B2HTX23 0003 - Black/Raft River Electric Cooperative

Thank you for the oppurtunity to provide comments in support of the Boardman to Hemingway Transmission build. This project is essential to providing clean, affordable and reliable energy to numerous customers in the entire South Idaho region, including parts of Northern Nevada and Northern Utah. This project must happen to effectuate long term transfer service without relying on conditional firm point to point transfer. This project wil also eliminate the reliance of interim service provided by market purchases, projecting savings upwards of 700 million dollars over the next 30 years. With these savings, eliminating the transmission constraints will also provide vast economic development oppurtunities, from food processing to mining loads. This will only be possible with access to firm,reliable electrical energy. Understanding there are still many details to work through, I am strongly in support of this project. I also support Bonneville Power not owning a portion of the line but allowing Idaho to retain its ownership to expedite and simplify the build out process, encouraging Bonneville to retain the appropiate reservation on this line to supply current and future load growth needs. Thank You for the oppurtunity to provide these comments in favor of moving forward with the Boardman to Hemingway transmission line build out.

B2HTX23 0006 - Gilligan/Liberty Gold / Pilot Gold USA

Liberty Gold, through its US entity Pilot Gold USA Inc., for the past 6 years has been exploring the viability of re-opening the historic Black Pine gold mine (operational in the 90's), located within Raft River Electrics' service territory. One of the most basic needs of any mining operation is access to sufficient, affordable and reliable electrical power. We have been in discussions with Raft River Electric since the beginning of this exploration period and as we have worked together to come up with solutions for our power needs, it has become obvious that the transmission system that Raft River Electric relies upon is severely restricted. It is our opinion that the B2H transmission project ("Project") is essential to sustaining reliable power supply in the service area, as demand increases. The Project needs to be taken extremely seriously and all possibilities explored to execute this in the shortest practical timeframe. Reliable power is an essential enabler of growth and development in the region and we offer our full corporate support for this very necessary initiative.

WELLS RURAL ELEC. CO.

Wells Rural Electric Company

PO Box 365 • Wells, NV 89835-0365 • (775)752-3328 • www.wrec.coop

February 9, 2023

Submitted via webportal

Kim Thompson
Bonneville Power Administration
Portland, OR 97232

Dear Kim,

On behalf of Wells Rural Electric Company (WREC), thank you for the opportunity to submit the following comments in response to Bonneville Power Administration's ("BPA") proposed terms for the agreements governing Boardman to Hemingway ("B2H") with Transfer Service. WREC appreciates the information shared in BPA's January 9, 2023 "Letter to the Region" and the materials and discussion during its January 23, 2023 Workshop.

WREC was incorporated in 1958 as a not-for-profit rural electric cooperative to provide electricity to consumers in the ranching valleys surrounding Wells, Nevada. WREC has since grown to serve 6,254 accounts held by 4,161 members spanning 10,552 square miles of service territory in Elko, Eureka and Lander Counties in Nevada and in Tooele County, Utah. In addition to relying on Transfer Service to connect our system to the larger Pacific Northwest and Nevada power grids, WREC owns and operates 111 miles of overhead transmission voltage powerline, 102 miles of underground distribution voltage powerline and 1,204 miles of overhead distribution voltage powerline, totaling 1,417 miles, to serve its members. As a low-density transfer customer located in Northeast Nevada, WREC's members depend on transfer service from BPA.

In agreement with Northwest Requirements Utilities (NRU) submitted comments, WREC supports the B2H with Transfer Service proposal as an alternative plan of service. WREC looks forward to the many improvements to regional transmission service that are expected to follow completion of the B2H line including increased reliability at a reduced cost.

Moving forward, WREC would appreciate additional detail with respect to BPA's plans for improving its ability to accommodate the forecasted load growth of preference customers like WREC who are directly impacted by the B2H Transfer Service proposal.

Additionally, WREC would appreciate information from BPA with respect to the following:

- Clarification from BPA that continued OATT service over Idaho Power's system will not limit BPA customers' ability to access additional transmission capacity to serve load growth, as needed, and on what terms additional capacity is expected to be made available.
- Confirmation that OATT service will in no way limit preference customers' ability to engage in future market opportunities and/or organized market participation, should such opportunities arise.
- Affirmative confirmation that there will be no change to the billing treatment of transfer customers impacted by the planned removal of a segment of BPA's Boardman-to-Ione transmission line.

We continue to appreciate the public process and open dialogue provided by BPA and look forward to continuing to work with you to secure reliable and cost-effective transfer service

We would welcome an opportunity to discuss or clarify any of the information provided. Please feel free to contact WREC by sending email to tballard@wrec.coop or by calling 775-752-1523.

Respectfully submitted,



Thad S. Ballard
Director of Administration and Power Supply

Northwest Requirements Utilities

(503) 233-5823
Fax (503) 233-3076
825 NE Multnomah, Suite 1135
Portland, Oregon 97232

February 9, 2023

Submitted via webportal

Kim Thompson
Bonneville Power Administration
Portland, OR 97232

Dear Kim:

Northwest Requirements Utilities ("NRU") submits the following comments in response to Bonneville Power Administration's ("BPA") proposed terms for the agreements governing Boardman to Hemingway ("B2H") with Transfer Service. NRU represents the interests of its 57 member utilities located in 7 states throughout the region, all of which are BPA Load Following and Network Transmission ("NT") transmission customers.

NRU has 37 members utilizing transfer service provided by BPA, including three members located in southeastern Idaho that are identified as Southeast Idaho Load Service (SILS) customers. Along with all of BPA's preference customers, NRU members benefit from the cost savings of BPA's transfer service program. Accordingly, we maintain a strong interest in the B2H with Transfer Service project and its potential to cost-effectively improve the reliability of transfer service throughout the region, and to enhance the financial benefits of transfer service overall.

NRU appreciates the information shared in BPA's January 9, 2023 "Letter to the Region" and the materials and discussion during its January 23 Workshop. NRU supports the B2H with Transfer Service proposal as an alternative plan of service that is both more cost effective than the status quo and that is expected to help facilitate construction of B2H in time for 2026 energization. Additionally, our members continue to look forward to the many improvements to regional transmission service that are expected to follow completion of the B2H line.

NRU supports BPA's proposed plan to no longer own or participate in the construction of the B2H project. We recognize the complexity associated with joint ownership, including the asset swaps and permitting hurdles that BPA's continued ownership would have entailed, and appreciate the improved efficiency of the proposed alternative. Further, NRU believes that the proposed plan of service will benefit impacted customers through continued facilitation of the construction of B2H, expected

improvements to reliability and reduced transmission constraints, along with considerable benefits to preference customers outside of the southeast Idaho and southwest Wyoming region resulting from improved integration capabilities with generation east of Boardman. Additionally, NRU understands that the elimination of the need for an additional wheel of transmission over PacifiCorp's system represents a significant improvement from both a cost and efficiency perspective, and the conversion of the affected customers from conditional firm point-to-point ("PTP") transmission to two Network Transmission Service (NITS) contracts represents an improvement to expected reliability as well. Finally, NRU looks forward to working with BPA to leverage the new NITS agreements to serve the considerable load growth that BPA's preference customers in the region are experiencing, and that is forecast to continue, which is considerably more difficult under the current PTP arrangements.

With respect to the financial impacts of BPA's B2H with Transfer Service proposal, NRU appreciates the financial analysis that BPA shared, representing an expected gross savings of roughly $720 million over the next 30 years, assuming continued OATT service from both Idaho Power and PacifiCorp. The improved energy cost assumptions stemming from BPA's reduced reliance on market purchases was particularly interesting, given the fact that BPA has not updated those financials to include the potential impacts of recent increased market volatility. While we would appreciate an updated financial analysis using 2022 market data, in the interim the combination of the quantitative and qualitative expected benefits remains compelling, and NRU looks forward to working with BPA and other stakeholders to continue to improve regional reliability and ensure resilient and cost-effective transfer service for all preference customers.

Moving forward, NRU would appreciate additional detail with respect to BPA's plans for improving its ability to accommodate the forecast load growth of preference customers; both for those customers who are directly impacted by the B2H Transfer Service proposal, and those who are otherwise impacted by the related asset swaps, rights conversions, and line removals that are anticipated as part of the service plan. Additionally, NRU would appreciate additional information from BPA with respect to the following:

- Clarification from BPA that continued OATT service over Idaho Power's system will not limit BPA customers' ability to access additional transmission capacity to serve load growth, as needed, and on what terms additional capacity is expected to be made available.
- Confirmation that OATT service will in no way limit preference customers' ability to engage in future market opportunities and/or organized market participation, should such opportunities arise.
- Given the potential for significant generation development in the area, the results of any analysis BPA has conducted or plans to conduct in the near future on the expected impact to BPA's ability to meet its SILS load service obligations, and the potential added value that bidirectional transmission rights may bring over a uniformly west-to-east strategy, going forward.
- The results of any analysis BPA has conducted or plans to conduct in the near future regarding potential impacts to the carbon content of BPA's "single system mix", given the potential for an exchange of and/or access to new resources in the region.
- Affirmative confirmation that there will be no change to the billing treatment of transfer customers impacted by the planned removal of a segment of BPA's Boardman-to-Ione transmission line.

We continue to appreciate the public process and open dialogue provided by BPA and look forward to continuing to work with you to secure reliable and cost-effective transfer service for BPA's preference customers. Thank you for considering these comments and questions.

Sincerely,

Matthew A. Schroettnig
Director of Operations and General Counsel

PNGC Power
Smart. Local. Connected.

February 9, 2023

Via Email:

Public Comment Portal

To: Bonneville Power Administration

From: PNGC Power

RE: PNGC Comments on Boardman to Hemingway with Transfer Service Project (B2H)

PNGC submits these comments regarding B2H project as a whole and the recent discussion held January 23, 2023. PNGC wants to reiterate the value from the B2H project for the region as a whole. Transmission development needs to continue, and this project is in the best interest of the region and public power overall. We continue to see the need for this project and support it moving forward.

The direction BPA is heading regarding the agreement with Idaho Power and PacifiCorp seems to make good economic and physical sense. Renewable and other generation is being developed and transmission like B2H is needed to integrate this generation and to maintain regionally reliability. The nature of the transmission system reliability is independent of ownership. B2H will benefit the region regardless of ownership. There is a need in the region for resource development to meet reliability concerns and state-mandated programs.

Next, we want to spend some time discussion the areas that are of critical impact and importance. Starting with transmission access and nondiscriminatory transfer service. The principle of "Comparability" between BPA's transfer and non-transfer (direct connect) transmission customers must be maintained. We are concerned about the initial direction BPA headed on this issue of comparability. We think it is important that all power (BPA and non-federal) that relies on the BPA system including a line like B2H that is obtained as a contractual right must be treated comparably. The scenario where customers are only able to utilize transfer service for federal power does not meet the "Comparability" requirement.

A large part of the value to this B2H decision is around the impact to transfer service. The benefit of creating two transmission wheels vs three to reach Southern ID loads cannot be negated by other transfer decisions. There is value in the proposed LT agreements, but that value diminishes if we cannot utilize the full set of resources the region is developing. We think BPA's direction on B2H is supported by a clear need for the line, but also can build on an important track-record of BPA building or buying transmission as it makes sense to the region and its customers. Treatment of all power flowing over that line fairly will help assure that we see development of renewable resources.

Pacific Northwest Generating Cooperative
8440 SE Sunnybrook Blvd •Clackamas, OR 97015
(503) 288-1234 • Fax (503) 288-2334 • www.pngcpower.com

Another area of critical importance that still needs to be answered is around the proposed asset swaps and redirects between the three parties as a part of the nonbinding term sheet. Better understanding on the impact to Central Oregon is needed.

We look forward to continued dialogue and engagement throughout this process.

PNGC Team

PUBLIC POWER COUNCIL
Bringing public power together

650 NE Holladay St, Suite 810
Portland, OR 97232
(503) 595-9770
www.ppcpdx.org

Submitted Electronically

February 9, 2023

John Hairston
Administrator, Bonneville Power Administration
Portland, OR 97232

RE: Southeast Idaho Loads and B2H Transfer Service Proposal

Dear Administrator Hairston,

The Public Power Council (PPC) appreciates the opportunity to comment on BPA's proposal for serving its preference customers in Southeast Idaho which BPA has referred to as the "B2H with transfer" approach. In developing plans of service for its transfer customers BPA should be striving to achieve two important objectives: 1) improving and enhancing the quality of service received by those transfer customers, and 2) reducing the costs of providing that service, which are borne by all of BPA's power customers. We acknowledge that these two objectives can sometimes require tradeoffs and would like to commend BPA staff's efforts to identify a creative solution which will achieve both of these results. This is a successful outcome, and we appreciate BPA staff's commitment to achieving these objectives with regards its Southeast Idaho plan of service.

We look forward to additional opportunities for BPA to apply these types of creative solutions to continue to enhance transfer service. BPA's transfer customers continue to struggle with transmission constraints into and across their territories. These constraints impact the service they can provide to their customers, as well as their options for developing and accessing non-federal resources, which could help ease the burden that preference customers put on the federal system post-2028. PPC looks forward to further discussion and will be looking for BPA to make some specific commitments in its decision letter regarding how it will partner with its customers to address these challenges and continue building on the successes of this proposal.

Regarding BPA's "B2H with Transfer Service" approach, PPC observes multiple benefits in this proposal compared to the status quo. First, PPC supports a solution that facilitates the construction of the Boardman to Hemmingway project. Construction of this project should improve service to BPA's customers and improve trade opportunities across the region. Second, we appreciate BPA's effort to develop an alternative that will improve and streamline transfer service to its Southeast Idaho load customers, as well as improve service for its transfer customers in Northern Nevada. The proposed agreement should provide more reliable service at lower costs compared to the status quo. The agency's efforts to reduce the costs of transfer service, which are borne by all power customers, are important and we acknowledge the progress on those efforts in this proposal.

Based on these benefits, PPC supports BPA's proposed alternative as an improvement over the status quo. As BPA works to implement this planned approach, it must ensure that it improves the outcome for all of its preference customers as intended. To that end, the agency should

commit that this planned approach will not negatively impact the current or planned load service to its preference customers.

As part of that commitment, PPC is seeking confirmation that the proposed Open Access Transmission Tariff (OATT) agreement with Idaho Power will not limit potential opportunities for BPA or its customers under future organized market outcomes. BPA should confirm with Idaho Power that it will facilitate the use of the transmission contract for delivery to BPA's transfer customers through any market construct that BPA may participate in the future – much like how the agency facilitated use of transmission on BPA's system in the Western Energy Imbalance Market (WEIM) for other entities prior to becoming an WEIM participant itself. Ensuring that Idaho Power will facilitate deliveries over the transmission through a market that BPA chooses to participate in is critical for providing "comparable" service with that provided to directly connected customers. It is particularly important to get this clarity given the unknowns surrounding future organized markets including which organized market opportunities BPA may pursue and the potential that Idaho Power could participate in the same organized market, a different organized market or no organized market at all. Confirmation of Idaho Power's willingness to facilitate such participation would ensure that BPA is not foreclosing or limiting future options for service to its transfer customers through its proposed approach.

Thank you for the opportunity to comment and again we commend and thank BPA staff for their thoughtful and creative approach to this important matter.

Sincerely,

Lauren Tenney Denison
Director, Market Policy & Grid Strategy
Public Power Council

United Electric
CO-OP INC.

February 9, 2023

Bonneville Power Administration
Attention: John Hairston, Administrator
Kim Thompson, VP Northwest Requirements Marketing

RE: United Electric Co-op, Inc. – Comments on Bonneville Power Administration's Proposal – Boardman to Hemingway with Transfer Service

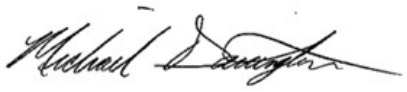
United Electric Co-op, Inc. ("United Electric") appreciates this opportunity to comment on Bonneville Power Administration's ("BPA") Boardman to Hemingway Transmission Line ("B2H") with Transfer Service proposal. United Electric is a preference customer of BPA with service area located in Minidoka and Cassia Counties of southern Idaho. United Electric commends BPA for its efforts in working with Idaho Power and Pacificorp to develop long-term and cost-effective solutions to relieve existing transmission constraints through the development of B2H and its continued commitment to serve its customers in southern Idaho and neighboring states through transfer service. With no direct connection to BPA's transmission assets, United Electric is dependent on transfer service provided by BPA over Idaho Power's transmission system.

United Electric supports the comments provided by Northwest Requirements Utilities and the Public Power Council on this topic and recommends that BPA consider the comments from these organizations applicable to the proposed plan of service associated with B2H. As outlined in BPA's January 9, 2023, Letter to the Region, United Electric recognizes and appreciates the expected savings to be approximately $720 million over 30 years, assuming continued open access service across parties' systems. In addition, United Electric specifically appreciates that construction and energization of the B2H project will increased capacity across Idaho Power's system to serve future load growth in accordance with Network Integration Transmission Service Agreements ("NITSAs") applicable to United Electric and neighboring preference customers.

Based on the benefits described in BPA's Letter to the Region, United Electric supports BPA's efforts to facilitate construction of the B2H project as added transmission capacity is greatly needed throughout the region. Moving forward, United Electric would appreciate further information and details regarding BPA's commitment to transfer service customers as the agency will have a necessary and important role in proper NITSA contract management and implementation, active involvement in third-party transmission providers' rate cases, and engagement with Federal Energy Regulatory Commission on the applicable open access transmission tariff terms and conditions.

United Electric appreciates and commends BPA's commitment to developing creative and cost-effective solutions to transmission projects and looks forward to the transfer service benefits the B2H project will provide.

Thank you,



Michael Darrington
General Manager
United Electric Co-op, Inc.

Idaho Power/506
Witness: Jared L. Ellsworth

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

Docket PCN 5

In the Matter of

IDAHO POWER COMPANY'S
PETITION FOR CERTIFICATE OF PUBLIC CONVENIENCE
AND NECESSITY

Resource Adequacy in the Pacific Northwest
(Mar. 2019)

February 21, 2023

Resource Adequacy in the Pacific Northwest

March 2019



Energy+Environmental Economics

Resource Adequacy in the Pacific Northwest

March 2019

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Study Sponsors

This study was sponsored by Puget Sound Energy, Avista, NorthWestern Energy, and the Public Generating Pool (PGP). PGP is a trade association representing 10 consumer-owned utilities in Oregon and Washington: Chelan County PUD, Clark Public Utilities, Cowlitz County PUD, Eugene Water and Electric Board, Klickitat PUD, Grant County PUD, Lewis County PUD, Tacoma Power, Snohomish County PUD, and Benton PUD.

Acknowledgements

E3 thanks the staff of the Northwest Power and Conservation Council (NWPCC) for providing data and technical review.

Conventions

The following conventions are used throughout this report:

- All costs are reported in **2016 dollars.**
- All levelized costs are assumed to be **levelized in real terms** (i.e., a stream of payments over the lifetime of the contract that is constant in real dollars).

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Acronyms

CONE	Cost of New Entry
DR	Demand Response
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
FOR	Forced Outage Rate
GENESYS	NWPCC's Generation Evaluation System Model
GHG	Greenhouse Gas
ISO	Independent System Operator
LOLE	Loss-of-Load Expectation
LOLF	Loss-of-Load Frequency
LOLP	Loss-of-Load Probability
MISO	Midwest Independent System Operator
MMT	Million Metric Ton
MTTR	Mean Time to Repair
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
PNUCC	Pacific Northwest Utilities Conference Committee
PRM	Planning Reserve Margin
RA	Resource Adequacy
RECAP	E3's Renewable Energy Capacity Planning Model
RPS	Renewables Portfolio Standard
RTO	Regional Transmission Operator
SPP	Southwest Power Pool
WECC	Western Electricity Coordinating Council

Executive Summary

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

This study finds that deep decarbonization of the Northwest grid is feasible without sacrificing reliable electric load service. But this study also finds that, absent technological breakthroughs, achieving 100% GHG reductions using *only* wind, solar, hydro, and energy storage is both impractical and prohibitively expensive. Firm capacity – capacity that can be relied upon to produce energy when it is needed the most, even during the most adverse weather conditions – is an important component of a deeply-decarbonized

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grid. Increased regional coordination is also a key to ensuring reliable electric service at reasonable cost under deep decarbonization.

Background and Approach

This study builds on the previous Northwest Low-Carbon Scenario Analysis conducted by E3 for PGP in 2017-2018 by focusing on long-run reliability and Resource Adequacy. This study uses E3's Renewable Energy Capacity Planning (RECAP) model, a loss-of-load-probability model designed specifically to test the Resource Adequacy of high-renewable electricity systems under a wide variety of weather conditions, renewable generation, and forced outages of electric generating resources. Specifically, this study examines four key questions:

- How to maintain Resource Adequacy in the 2020-2030 timeframe under growing loads and increasing coal retirements?
- How to maintain Resource Adequacy in the 2050 timeframe under different levels of carbon abatement goals, including zero carbon?
- How much effective capacity can be provided by wind, solar, electric energy storage, and demand response?
- How much firm capacity is needed to maintain reliable electric service at various levels of carbon reductions?

Key Findings

1. It is possible to maintain Resource Adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient **firm capacity** is available during periods of low wind, solar, and hydro production;
    - Natural gas generation is the most economic source of firm capacity today;

- Adding new gas generation capacity is not inconsistent with deep reductions in carbon emissions because the significant quantities of zero-marginal-cost renewables will ensure that gas is only used during reliability events;
- Wind, solar, demand response, and short-duration energy storage can contribute but have important limitations in their ability to meet Northwest Resource Adequacy needs;
- Other potential low-carbon firm capacity solutions include (1) new nuclear generation, (2) fossil generation with carbon capture and sequestration, (3) ultra-long duration electricity storage, and (4) replacing conventional natural gas with carbon-neutral gas such as hydrogen or biogas.

2. It would be **extremely costly and impractical** to replace all carbon-emitting firm generation capacity with solar, wind, and storage, due to the very large quantities of these resources that would be required;

- Firm capacity is needed to meet the new paradigm of reliability planning under deep decarbonization, in which the electricity system must be designed to withstand prolonged periods of low renewable production once storage has depleted; renewable overbuild is the most economic solution to completely replace carbon-emitting resources but requires a 2x buildout that results in curtailment of almost half of all wind and solar production.

3. The Northwest is expected to need new capacity in the near term in order to maintain an acceptable level of Resource Adequacy after planned coal retirements.

4. Current planning practices risk underinvestment in the new capacity needed to ensure Resource Adequacy at acceptable levels;

- Reliance on market purchases or front-office transactions (FOTs) reduces the cost of meeting Resource Adequacy needs on a regional basis by taking advantage of load and resource diversity among utilities in the region;
- Capacity resources are not firm without a firm fuel supply; investment in fuel delivery infrastructure may be required to ensure Resource Adequacy even under a deep decarbonization trajectory;

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- Because the region lacks a formal mechanism for ensuring adequate physical firm capacity, there is a risk that reliance on market transactions may result in double-counting of available surplus generation capacity;
- The region might benefit from and should investigate a formal mechanism to share planning reserves on a regional basis, which may help ensure sufficient physical firm capacity and reduce the quantity of capacity required to maintain Resource Adequacy.

1 Introduction

1.1 Study Background & Context

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

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1.2 Prior Studies

In 2017-2018, E3 completed a series of studies[1] for PGP and Climate Solutions to evaluate the costs of alternative electricity decarbonization strategies in Washington and Oregon. These studies were conducted using E3's RESOLVE model, which is a dispatch and investment model that identifies optimal long-term generation and transmission investments in the electric system to meet various decarbonization and renewable energy targets. The studies found that the least-cost pathway to reduce greenhouse gases from electricity generation is to replace coal generation with a mix of energy efficiency, renewables, and natural gas generation. While these studies examined in great detail the economics of new resources needed to achieve decarbonization, including the type, quantity, and location of these resources, they did not look in-depth at reliability and Resource Adequacy.

1.3 Purpose of Study

This study builds on the previous Northwest Low-Carbon Scenario Analysis conducted by E3 for PGP in 2017-2018 by focusing on long-run reliability and Resource Adequacy. This study uses E3's Renewable Energy Capacity Planning (RECAP) model, a loss-of-load-probability model designed specifically to test the Resource Adequacy of high-renewable electricity systems under a wide variety of weather conditions, renewable generation, and forced outages of electric generating resources. Specifically, this study examines four key questions:

- How to maintain Resource Adequacy in the 2020-2030 timeframe under growing loads and increasing coal retirements?
- How to maintain Resource Adequacy in the 2050 timeframe under different levels of carbon abatement goals, including zero carbon?

[1] https://www.ethree.com/projects/study-policies-decarbonize-electric-sector-northwest-public-generating-pool-2017-present/

- How much effective capacity can be provided by wind, solar, electric energy storage, and demand response?
- How much firm capacity is needed to maintain reliable electric service at various levels of carbon reductions?

1.4 Report Contents

The remainder of this report is organized as follows:

- Section 2 introduces Resource Adequacy and current practices in the Northwest
- Section 3 describes the study's modeling approach
- Section 4 highlights key inputs and assumptions used in the modeling
- Section 5 presents results across a variety of time horizons and resource portfolios
- Section 6 discusses implications of the results
- Section 7 summarizes the study's conclusions and lessons learned

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2 Resource Adequacy in the Northwest

2.1 What is Resource Adequacy?

Resource adequacy is the ability of an electric power system to serve load across a broad range of weather and system operating conditions, subject to a long-run standard on the maximum frequency of reliability events where generation is insufficient to serve all load. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability. Ensuring resource adequacy is an important goal for utilities seeking to provide reliable service to their customers.

While utility portfolios are typically designed to meet specified resource adequacy targets, there is no single mandatory or voluntary national standard for resource adequacy. Across North America, resource adequacy standards are established by utilities, regulatory commissions, and regional transmission operators, and each uses its own conventions to do so. The North American Electric Reliability Council (NERC) and the Western Electric Coordinating Council (WECC) publish information about resource adequacy but have no formal governing role.

While a variety of approaches are used, the industry best practice is to establish a standard for resource adequacy using a two-step process:

+ **Loss-of-load-probability (LOLP) modeling:** LOLP modeling uses statistical techniques and/or Monte Carlo approaches to simulate the capability of a generation portfolio to produce sufficient generation to meet loads across a wide range of different conditions. Utilities plan the system to meet a specific reliability standard that is measured through LOLP modeling such as the expected frequency and/or size of reliability events; a relatively common standard used in LOLP modeling

is "one day in ten years," which is often translated to an expectation of 24 hours of lost load every ten years, or 2.4 hours per year.[2]

+ **Planning reserve margin (PRM) requirements:** Utilities then determine the required PRM necessary to ensure that the system will meet the specific the reliability standard from the LOLP modeling. A PRM establishes a total requirement for capacity based on the peak demand of an electric system plus some reserve margin to account for unexpected outages and extreme conditions; reserve margin requirements typically vary among utilities between 12-19% above peak demand. To meet this need, capacity from resources that can produce their full power on demand (e.g., nuclear, gas, coal) are typically counted at or near 100%, whereas resources that are constrained in their availability or ability to dispatch (e.g., hydro, storage, wind, solar) are typically de-rated below full capacity.

While LOLP modeling is more technically rigorous, most utilities perform LOLP modeling relatively infrequently and use a PRM requirement to heuristically ensure compliance with a specific reliability standard due to its relative simplicity and ease of implementation. The concept and application of a PRM to measure resource adequacy has historically worked well in a paradigm in which most generation capacity is "firm"; that is, the resource will be available to dispatch to full capacity, except in the event of unexpected forced outages. Under this paradigm, as long as the system has sufficient capacity to meet its peak demand (plus some reserve margin for extreme weather and unexpected forced outages), it will be capable of serving load throughout the rest of the year as well.

However, growing penetrations of variable (e.g., wind and solar) and energy-limited (e.g., hydro, electric energy storage, and demand response) resources require the application of increasingly sophisticated modeling tools to determine the appropriate PRM and to measure the contribution of each resource towards resource adequacy. Because wind and solar do not always generate during the system peak and because storage may run out of charge while it is serving the system peak, these resources are often de-

[2] Other common interpretations of the "one day in ten year" standard include 1 "event" (of unspecified duration) in ten years or "one hour in ten years" i.e., 0.1 hrs/yr

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rated below the capability of a fully dispatchable thermal generator when counted toward meeting the PRM.

2.2 Planning Practices in the Northwest

A number of entities within the Northwest conduct analysis and planning for resource adequacy within the region. Under its charter to ensure prudent management of the region's federal hydro system while balancing environmental and energy needs, the Northwest Power and Conservation Council (NWPCC) conducts regular assessments of the resource adequacy position for the portion of the Northwest region served by the Bonneville Power Administration. The NWPCC has established an informal reliability target for the region of 5% annual loss of load probability[3]—a metric that ensures that the region will experience reliability events in fewer than one in twenty years—and uses GENESYS, a stochastic LOLP model with a robust treatment of the resource's variable hydroelectric conditions and capabilities, to examine whether regional resources are sufficient to meet this target on a five-year ahead basis.[4] These studies provide valuable information referenced by regulators and utilities throughout the region.

While the work of the Council is widely regarded as the most complete regional assessment of resource adequacy for the smaller region, the Council itself holds no formal decision-making authority to prescribe new capacity procurement or to enforce its reliability standards. Instead, the ultimate administration of resource adequacy lies in the hands of individual utilities, often subject to the oversight of state commissions. Most resource adequacy planning occurs within the planning and procurement processes

[3] This Council's standard, which focuses only on whether a reliability event occurred within a year, is unique to the Northwest and is not widely used throughout the rest of the North America

[4] The most recent of these reports, the Pacific Northwest Power Supply Adequacy Assessment for 2023, is available at: **https://www.nwcouncil.org/sites/default/files/2018-7.pdf** (accessed January 18, 2019).

of utilities: individual utilities submit integrated resource plans (IRPs) that consider long-term resource adequacy needs and conduct resource solicitations to satisfy those needs.

Utilities rely on a combination of self-owned generation, bilateral contracts, and front-office transactions (FOTs) to satisfy their resource adequacy requirements. FOTs represent short-term firm market purchases for physical power delivery. FOTs are contracted on both a month-ahead, day-ahead and hour-ahead basis. A survey of the utility IRPs in the Northwest reveals that most of the utilities expect to meet a significant portion of their peak capacity requirements in using FOTs.

FOTs may be available to utilities for several potential reasons including 1) the region as a whole has a capacity surplus and some generators are uncontracted to a specific utility or 2) natural load diversity between utilities such that one utility may have excess generation during another's peak load conditions and vice versa. The use of FOTs in place of designated firm resources can result in lower costs of providing electric service, as the cost of contracting with existing resources is generally lower than the cost of constructing new resources.

However, as loads grow in the region and coal generation retires, the region's capacity surplus is shrinking, and questions are emerging about whether sufficient resources will be available for utilities to contract with for month-ahead and day-ahead capacity products. In a market with tight load-resource balance, extensive reliance on FOTs risks under-investment in the firm capacity resources needed for reliable load service.

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Table 1: Contribution of FOTs Toward Peak Capacity Requirements in 2018 in the Northwest

Utility	Capacity Requirement (MW)	Front Office Transactions (MW)	% of Capacity Requirement from FOTs
Puget Sound[5]	6,100	1,800	30%
Avista[6]	2,150	-	0%
Idaho Power[7]	3,078	313	10%
PacifiCorp[8]	11,645	462	4%
BPA[9]	11,506	-	0%
PGE[10]	4,209	106	3%
NorthWestern[11]	1,205	503	42%

[5] Figure 6-7: Available Mid C Tx plus Additional Mid-C Tx w/ renewals in PSE 2017 IRP: https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/8a_2017_PSE_IRP_Chapter_book_compressed_110717.pdf?la=en&revision=bb9e004c-9da0-4f75-a594-6c30dd6223f4&hash=75800198E4E8517954C63B3D01E498F2C5AC10C2

[6] Figure 6.1 (for peak load), Chapter 4 Tables for resources in Avista 2017 IRP: https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2017-electric-irp-final.pdf?la=en

[7] Table 9.11 in Idaho Power 2017 IRP: https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf

[8] Table 5.2 in PacifiCorp 2017 IRP (Interruptible Contracts + Purchases): https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf

[9] Bottom of the page in BPA fact sheet: https://www.bpa.gov/news/pubs/GeneralPublications/gi-BPA-Facts.pdf

[10] PGE 2016 IRP Table P-1 Spot Market Purchases (rounded from 106), Capacity Need : https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/2016-irp

[11] Table 2-2 for peak load and netted out existing resources (Ch. 8) @ 12%PRM from NorthWestern Energy 2015 IRP: https://www.northwesternenergy.com/our-company/regulatory-environment/2015-electricity-supply-resource-procurement-plan

3 Modeling Approach

3.1 Renewable Energy Capacity Planning (RECAP) Model

3.1.1 MODEL OVERVIEW

This study assesses the resource adequacy of electric generating resource portfolios for different decarbonization scenarios in the Northwest region using E3's Renewable Energy Capacity Planning (RECAP) model. RECAP is a loss-of-load-probability model developed by E3 that has been used extensively to test the resource adequacy of electric systems across the North American continent, including California, Hawaii, Canada, the Pacific Northwest, the Upper Midwest, Texas, and Florida.

RECAP calculates a number of reliability metrics which are used to assess the resource adequacy for an electricity system with a given set of loads and generating resources.

- **Loss of Load Expectation (hrs/yr) – LOLE**
  - The total number of hours in a year where load + reserves exceeds generation
- **Expected Unserved Energy (MWh/yr) – EUE**
  - The total quantity of unserved energy in a year when load + reserves exceeds generation
- **Loss of Load Probability (%/yr) – LOLP**
  - The probability in a year that load + reserves exceeds generation at any time
- **Effective Load Carrying Capability (%) – ELCC**
  - The additional load met by an incremental generator while maintaining the same level of system reliability (used for dispatch-limited resources such as wind, solar, storage, hydro, and demand response). Equivalently, this is the quantity of perfectly dispatchable

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generation that could be removed from the system by an incremental dispatch-limited generator

+ **Planning Reserve Margin (%) – PRM**
    - The resource margin above a 1-in-2 peak load, in %, that is required in order to meet a specific reliability standard (such as 2.4 hrs./yr. LOLE)

This study uses 2.4 hrs./yr. LOLE reliability standard which is based on a commonly accepted 1-day-in-10-year standard. All portfolios that are developed by RECAP in this analysis for resource adequacy are designed to meet a 2.4 hrs./yr. LOLE standard.

RECAP calculates reliability statistics by simulating the electric system with a specific set of generating resources and loads under a wide variety of weather years, renewable generation years, and stochastic forced outages of electric generation resources and imports on transmission. By simulating the system thousands of times with different combinations of these factors, RECAP provides robust, stochastic estimation of LOLE and other reliability statistics.

RECAP was specifically designed to calculate the reliability of electric systems operating under high penetrations of renewable energy and storage. Correlations enforced within the model capture linkage among load, weather, and renewable generation conditions. Time-sequential simulation tracks the state of charge and energy availability for dispatch-limited resources such as hydro, energy storage, and demand response.

3.1.2 MODEL METHODOLOGY

The steps of the RECAP modeling process are shown below in Figure 1. RECAP calculates long-run resource availability through Monte Carlo simulation of electricity system resource availability using weather conditions from 1948-2017. Each simulation begins on January 1, 1948 and runs hourly through December 31, 2017. Hourly electric loads for 1948-2017 are synthesized using statistical analysis of actual load shapes and weather conditions for 2014-2017 combined with recorded historical weather conditions.

Then, hourly wind and solar generation profiles are drawn from simulations created by the National Renewable Energy Laboratory (NREL) and paired with historical weather days through an E3-created day-matching algorithm. Next, nameplate capacity and forced outage rates (FOR) for thermal generation are drawn from various sources including the GENESYS database and the Western Electric Coordinating Council's Anchor Data Set. Hydro is dispatched based on the load net of renewable and thermal generation. Annual hydro generation values are drawn randomly from 1929-2008 water years and shaped to calendar months and weeks based on the Northwest Power and Conservation Council's GENESYS model. For each hydro year, we identify all the hydro dispatch constraints including maximum and minimum power capacity, 2-hour to 10-hour sustained peaking limits, and hydro budget, specific to the randomly-drawn hydro condition. For each x-hour sustained peaking limit (where x = 2, 4, and 10), RECAP dispatches hydro so that the average capacity over consecutive x hours does not exceed the sustained peaking capability. Overall, hydro is dispatched to minimize the post-hydro net load subject to the above constraints. In other words, hydro is used within assumed constraints to meet peak load needs while minimizing loss-of-load. Finally, RECAP uses storage and demand response to tackle the loss-of-load hours and storage is only discharged during loss-of-load hours. A more detailed description of the RECAP model is in Appendix B.2.

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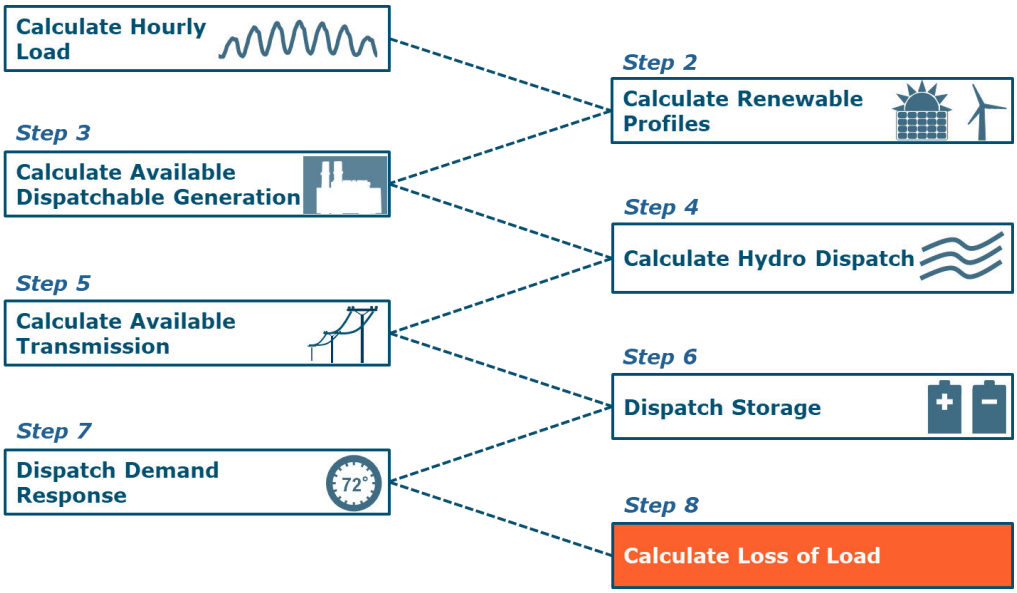
Figure 1: Overview of RECAP Model



3.1.3 PORTFOLIO DEVELOPMENT

RECAP is used in this study to both test the reliability of the existing 2018 Greater Northwest electricity system as well as to determine a total capacity need in 2030 and to develop portfolios in 2050 under various levels of decarbonization that meet a 1-day-in-10-year reliability standard of 2.4 hrs./yr.

To develop each 2050 decarbonization portfolio, RECAP calculates the reliability of the system in 2050 after forecasted load growth and the removal of all fossil generation but the maintenance of all existing carbon-free resources. Unsurprisingly, these portfolios are significantly less reliable than the required 2.4 hrs./yr. nor do they deliver enough carbon-free generation to meet the various decarbonization targets. To improve the reliability and increase GHG-free generation of these portfolios, RECAP tests the

contribution of small, equal-cost increments of candidate GHG-free resources. The seven candidate resources in this study are:

- Northwest Wind (WA/OR)
- Montana Wind
- Wyoming Wind
- Solar (based on an assumed diverse mix of resources from each state)
- 4-Hour Storage
- 8-Hour Storage
- 16-Hour Storage

The resource that improves reliability the most (as measured in loss-of-load-expectation) is then added to the system. This process is repeated until the delivered GHG-free generation is sufficient to meet the GHG target (e.g., 80% reduction) for each particular scenario. Once a portfolio has achieved the objective GHG target, RECAP calculates the residual quantity of perfect firm capacity that is needed to bring the portfolio in compliance with a reliability standard of 2.4 hrs./yr. This perfect firm MW capacity is converted to MW of natural gas capacity by grossing up by 5% to account for forced outages. Natural gas capacity is used because it is the most economic source of firm capacity. To the extent that other carbon-free resources can substitute for natural gas capacity, this is reflected in deeper decarbonization portfolios that have higher quantities of wind, solar, and storage along with a smaller residual requirement for firm natural gas capacity.

Figure 2 illustrates a simple example of this portfolio development process where RECAP has 3 candidate resources: wind, solar, and storage. The model evaluates the contribution to reliability of equal-cost increments of the three candidate resources and selects the resource that improves reliability the most. From that new portfolio, the process is repeated until either the system reaches a reliability standard of 2.4 or a particular GHG target is achieved.

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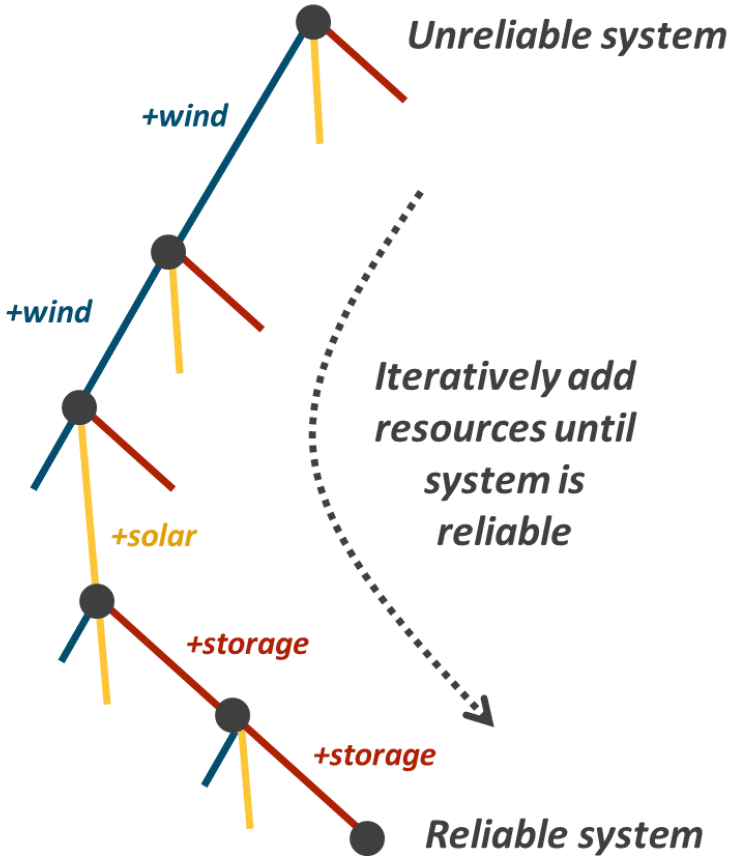
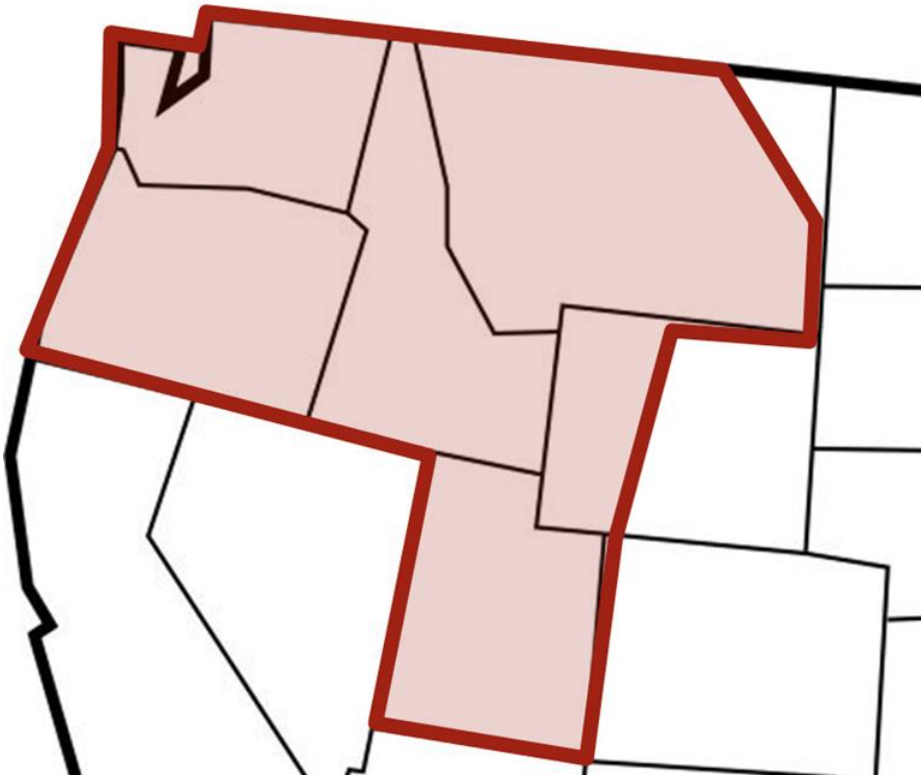
Figure 2: RECAP Portfolio Development Process



3.2 Study Region

The geographic region for this study consists of the U.S. portion of the Northwest Power Pool (NWPP), excluding Nevada, which this study refers to as the "Greater Northwest". This region includes the states of Washington, Oregon, Idaho, Utah, and parts of Montana and Wyoming.

Figure 3: The study region - The Greater Northwest



It is important to note that this is a larger region than was analyzed in the prior E3 decarbonization work in the Northwest which only analyzed a "Core Northwest" region consisting of Oregon, Washington, northern Idaho and Western Montana. The larger footprint encompasses the utilities that have traditionally coordinated operational efficiencies through programs under the Northwest Power Pool and includes utilities that typically transact with each other to maintain resource adequacy and optimize resource portfolios. The larger region also incorporates a footprint that allows for diversity of both load and resources which minimizes the need for firm capacity. The Balancing Authority Areas (BAAs) that were included in this Greater Northwest study region are listed in Table 2.

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Table 2: List of Balancing Authorities Included in Study

Balancing Authority Areas Included in Greater Northwest Study Region		
Avista	Bonneville Power Administration	Chelan County PUD
Douglas County PUD	Grant County PUD	Idaho Power
NorthWestern	PacifiCorp East	PacifiCorp West
Portland General Electric	Puget Sound Energy	Seattle City Light
Tacoma Power	Western Area Power Administration Upper Great Plains	

3.3 Scenarios & Sensitivities

This study examines the resource adequacy requirements of the Greater Northwest region across multiple timeframes and decarbonization scenarios.

+ **Near-term (2018)** reliability statistics are calculated for today's system based on 2018 existing loads and resources. These results are presented to give the reader a sense of existing challenges and as a reference for other scenario results.
+ **Medium-term (2030)** reliability statistics are calculated in 2030 for two scenarios: a *Reference* scenario and a *No Coal* scenario. The *Reference* scenario includes the impact of expected load growth and announced generation retirements, notably the Boardman, Centralia, and Colstrip coal plants. The *No Coal* scenario assumes that all coal is retired.
+ **Long-term (2050)** reliability statistics are calculated in 2050 for multiple scenarios including a *Reference* scenario and for a range of decarbonization targets. The *Reference* scenario includes the impact of load growth, growth in renewable capacity to meet current RPS policy goals, and the retirement of all coal. Decarbonization scenarios assume GHG emissions are reduced to 60%, 80%, 90%, 98% and 100% below 1990 GHG levels through the addition of wind, solar, and electric energy storage.

These scenarios are summarized in Table 3.

Table 3: List of Scenarios and Descriptions

Analysis Period	Scenario	Description
Near-term (2018)	Reference	2018 Existing Loads and Resources
Medium-Term (2030)	Reference	Includes load growth through 2030 and announced generation retirements, notably the Boardman, Centralia, and Colstrip coal plants
	No Coal	Same as 2030 reference but all coal generation in the region is retired (11 GW)
Long-Term (2050)	Reference	Includes load growth through 2050, renewable capacity additions to meet RPS targets, and ***retirement of all coal generation*** (11 GW)
	60% GHG Reduction	Scenarios achieve specified greenhouse gas reduction (relative to 1990 levels) through addition of solar, wind, and energy storage; sufficient gas generating capacity is maintained to ensure reliability (except in 100% GHG Reduction)
	80% GHG Reduction	
	90% GHG Reduction	
	98% GHG Reduction	
	100% GHG Reduction	

This study further explores the potential resource adequacy needs of a 100% carbon free electricity system in 2050 recognizing that emerging technologies beyond wind, solar, and electric energy storage that are not yet available today may come to play a significant role in the region's energy future. To better understand how those technologies might impact the viability of achieving this ambitious goal, the study includes several sensitivity analyses of the 100% GHG Reduction scenario that assume the wide-scale availability of several such emerging technology options. These sensitivities are described in Table 4.

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Table 4: 100% GHG Reduction in 2050 Sensitivities

Sensitivity Name	Description
Clean Baseload	Assesses the impact of technology that generates reliable baseload power with zero GHG emissions. This scenario might require a technology such as a small modular nuclear reactor (SMR), fossil generation with 100% carbon capture and sequestration, or other undeveloped or commercially unproven technology.
Ultra-Long Duration Storage	Assesses the impact of an ultra-long duration electric energy storage technology (e.g., 100's of hours) that can be used to integrate wind and solar. This technology is not commercially available today at reasonable cost.
Biogas	Assesses the impact of a GHG free fuel (e.g., biogas, renewable natural gas, etc.) that could be used with existing dispatchable generation capacity.

3.4 Key Portfolio Metrics

Each of the scenarios is evaluated using several different metrics which are defined below:

3.4.1 CLEAN ENERGY METRICS

A number of metrics are used to characterize the greenhouse gas content of generation within the region in each of the scenarios. These are:

+ Greenhouse Gas Emissions (MMT CO2): the annual quantity of greenhouse gas emissions attributed to ratepayers of the Greater Northwest region, measured in million metric tons.
+ Greenhouse Gas Reduction (%): the reduction below 1990 emission levels (approximately 60 million metric tons) for the Greater Northwest region.
+ Clean Portfolio Standard (%): the total quantity of GHG-free generation (including renewable, hydro, and nuclear) divided by retail electricity sales. Because this metric allows the region to retain the clean attribute for exported electricity and offset in-region or imported natural gas

generation, this metric can achieve or exceed 100% without reducing GHGs to zero. This metric is presented because it is a common policy target metric across many jurisdictions to measure clean energy progress and is the near-universal metric used for state-level Renewables Portfolio Standards. This metric is consistent with California's SB 100 which mandates 100% clean energy by 2045.

+ **GHG-Free Generation (%):** the total quantity of GHG-free generation, minus exported GHG-free generation, divided by total wholesale load. For this metric, exported clean energy cannot be netted against in-region or imported natural gas generation. When this metric reaches 100%, GHG emissions have been reduced to zero.

3.4.2 COST METRICS

+ **Renewable Curtailment (%):** the total quantity of wind and solar generation that cannot be delivered to loads in the region or exported, expressed as a share of total available potential generation from wind and solar resources.

+ **Annual Cost Delta ($B)** is the annual cost in 2050 of decarbonization scenarios relative to the 2050 Reference scenario. While the 2050 Reference scenario will require significant costs to meet load growth, this metric only evaluates the *change* in costs for each decarbonization scenario relative to the Reference scenario. By definition, the 2050 Reference scenario has an annual cost delta of zero. The annual cost delta is calculated by comparing the incremental cost of new wind, solar, and storage resources to the avoided cost of natural gas capital and operational costs.

+ **Additional Cost ($/MWh)** is the total annual cost delta ($B) divided by total wholesale load, which provides an average measure of the incremental rate impact borne by ratepayers within the region. While this metric helps to contextualize the annual cost delta, it is important to note that the incremental cost will not be borne equally by all load within the Greater Northwest region and some utilities may experience higher additional costs.

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3.5 Study Caveats

3.5.1 COST RESULTS

The study reports the incremental costs of achieving various GHG targets relative to the cost of the reference scenario. While the method used to estimate capital and dispatch costs is robust, it does not entail optimization and the results should be regarded as high-level estimates. For this reason, a range of potential incremental costs are reported rather than a point estimate. The range is determined by varying the cost of wind, solar, energy storage and natural gas.

3.5.2 HYDRO DISPATCH

For this study, RECAP utilizes a range of hydro conditions based on NWPCC data covering the time period 1929 – 2008. Within each hydro year, hydroelectric energy "budgets" for each month are allocated to individual weeks and then dispatched to minimize net load, subject to sustained peaking limit constraints that are appropriate for the water conditions. Hydro resources are dispatched optimally within each week with perfect foresight. There are many real-life issues such as biological conditions, flood control, coordination between different project operators, and others that may constrain hydro operations further than what is assumed for this study.

3.5.3 TRANSMISSION CONSTRAINTS

This analysis treats the Greater Northwest region as one zone with no internal transmission constraints or transactional friction. In reality, there are constraints in the region that may prevent a resource in one corner of the region from being able to serve load in another corner. To the extent that constraints exist, the Greater Northwest region may be less resource adequate than is calculated in this study and additional effective capacity would be required to achieve the calculated level of resource adequacy. It is assumed that new transmission can be developed to deliver energy from new renewable resources to wherever it

is needed, for a cost that is represented by the generic transmission cost adder applied to resources in different locations.

3.5.4 INDIVIDUAL UTILITY RESULTS

Cost and resource results in this study are presented from the system perspective and represent an aggregation of the entire Greater Northwest region. These societal costs include all capital investment costs (i.e., "steel in the ground") and operational costs (i.e., fuel and operation and maintenance) that are incurred in the region. The question of how these societal costs are allocated between individual utilities is not addressed in this study, but costs for individual utilities may be higher or lower compared to the region as a whole. Utilities with a relatively higher composition of fossil resources today are likely to bear a higher cost than utilities with a higher composition of fossil-free resources.

Resource adequacy needs will also be different for each utility as individual systems will need a higher planning reserve margin than the Greater Northwest region as a whole due to smaller size and less diversity. The capacity contribution of renewables will be different for individual utilities due to differences in the timing of peak loads and renewable generation production.

3.5.5 RENEWABLE RESOURCE AVALIBILITY AND LAND USE

The renewable resource availability assumed for this study is based on technical potential as assessed by NREL. It is assumed wind and solar generation can be developed in each location modeled in this study up to the technical potential. However, the land consumption is significant for some scenarios and it is not clear whether enough suitable sites can be found to develop the large quantities of resources needed for some scenarios. Land use is also a significant concern for the new transmission corridors that would be required.

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4 Key Inputs & Assumptions

4.1 Load Forecast

The Greater Northwest region had an annual load of 247 TWh and peak load of 43 GW in 2017. This data was obtained by aggregating hourly load data from the Western Electric Coordinating Council (WECC) for each of the selected balancing authority areas in the Greater Northwest region.

This study assumes annual load growth of **1.3% pre-energy efficiency** and **0.7% post-energy efficiency**. This assumption is consistent with the previous E3 decarbonization work for Oregon and Washington and is benchmarked to multiple long-term publicly available projections listed in Table 5. The post-energy efficiency growth rate includes the impact of all cost-effective energy efficiency identified by the NWPCC, scaled up to the full Greater Northwest region and assumed to continue beyond the end of the Council's time horizon. Electrification of vehicles and buildings is only included to the extent that it is reflected in these load growth forecasts. For example, the NWPCC forecast includes the impact of 1.1 million electric vehicles by 2030.

In general, E3 believes these load growth forecasts are conservatively low because they exclude the effect of vehicle and building electrification that would be expected in a deeply decarbonized economy. To the extent that electrification is higher than forecasted in this study, resource adequacy requirements would also increase. In this study, total loads increase 25% by 2050, whereas other studies[12] that have comprehensively examined cost-effective strategies for economy-wide decarbonization include

[12] https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf

significant quantities of building, vehicle, and industry electrification that cause electricity-sector loads to grow by upwards of 60% by 2050 even with significant investments in energy efficiency.

Table 5. Annual load growth forecasts for the Northwest

Source	Pre EE	Post EE
PNUCC Load Forecast	1.7%	0.9%
BPA White Book	1.1%	-
NWPCC 7th Plan	0.9%	0.0%
WECC TEPPC 2026 Common Case	-	1.3%
E3 Assumption	**1.3%**	**0.7%**

Hourly load profiles are assumed to be constant through the analysis period and do not account for any potential impact due to electrification of loads or climate change. The Greater Northwest system is a winter peaking system with loads that are highest during cold snaps on December and January mornings and evenings. An illustration of the average month/hour load profile for the Greater Northwest is shown in Figure 4.

Figure 4: Month/Hour Average Hourly Load in the Greater Northwest (GW)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	28	27	26	26	26	27	29	32	33	34	33	33	32	32	31	31	31	32	34	34	33	33	31	29
Feb	26	25	25	25	25	26	28	31	32	32	32	31	31	30	29	29	29	30	31	32	32	31	30	28
Mar	24	23	23	23	24	25	28	30	30	30	30	29	29	28	28	27	27	28	28	29	29	28	27	25
Apr	22	22	21	22	22	24	27	28	28	28	28	27	27	27	26	26	26	26	27	27	28	27	25	23
May	22	21	21	21	21	22	24	26	26	27	27	27	27	27	27	27	27	27	27	27	27	27	25	23
Jun	23	22	21	21	22	22	24	26	27	27	28	28	29	29	29	29	29	29	29	29	28	28	26	24
Jul	24	23	22	22	22	23	24	26	27	28	29	30	31	31	32	32	32	32	32	31	30	30	28	26
Aug	23	22	21	21	21	22	24	25	26	27	28	29	29	30	30	31	31	31	30	30	30	28	26	24
Sep	21	20	20	20	20	22	24	25	26	26	26	27	27	27	27	27	27	28	27	28	27	26	24	22
Oct	21	21	20	20	21	23	25	26	27	27	27	27	27	26	26	26	26	27	27	28	27	26	24	22
Nov	24	23	23	23	23	24	26	28	30	30	30	29	29	28	28	28	28	29	31	30	30	29	28	26
Dec	27	26	26	26	26	27	29	31	33	33	33	32	32	31	31	31	31	33	34	34	33	33	31	29

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Projecting these hourly loads using the post-energy efficiency load growth forecasts yields the following load projections in 2030 and 2050.

Table 6. Load projections in 2030 and 2050 for the Greater NW Region

Load	2018	2030	2050
Median Peak Load (GW)	43	47	54
Annual Energy Load (TWh)	247	269	309

To evaluate the reliability of the Greater Northwest system under a range of weather conditions, hourly load forecasts for 2030 and 2050 are developed over seventy years of weather conditions (1948-2017). Historical weather data was obtained from the National Oceanic and Atmospheric Administration (NOAA) for the following sites in the Greater Northwest region.

Table 7: List of NOAA Sites for Historical Temperature Data

City	Site ID
Billings, MT	USW00024033
Boise, ID	USW00024131
Portland, OR	USW00024229
Salt Lake City, UT	USW00024127
Seattle, WA	USW00024233
Spokane, WA	USW00024157

4.2 Existing Resources

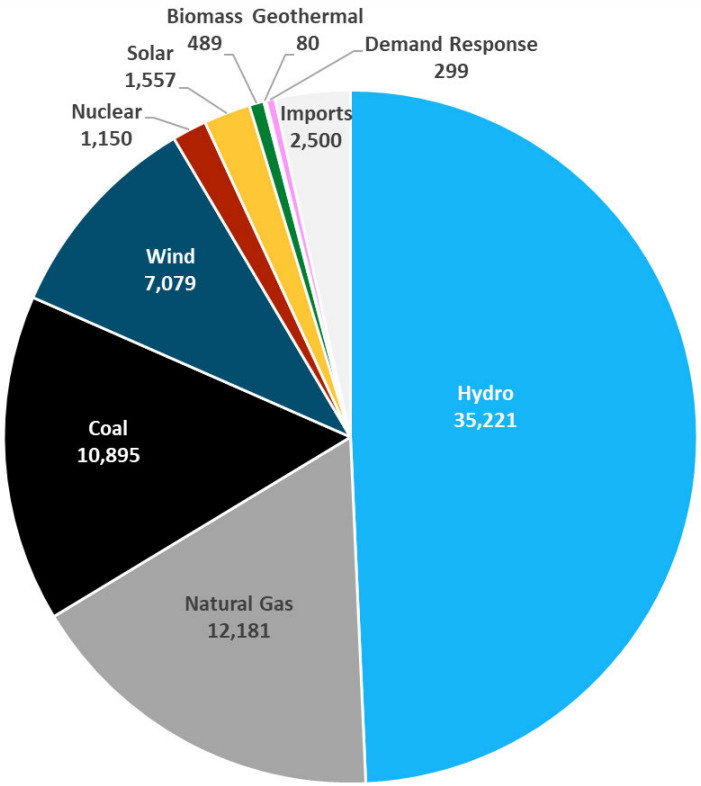
A dataset of existing generating resources in the Greater Northwest was derived from two sources: 1) the NWPCC's GENESYS model, used to characterize all plants within the Council's planning footprint; and 2)

the WECC's Anchor Data Set, used to gather input data for all existing plants in areas outside of the NWPCC's footprint. For each resource, the dataset contains:

- Dependable capacity (MW)
- Location
- Commission and announced retirement date
- Forced outage rate (FOR) and mean time to repair (MTTR)

A breakdown of existing resources by type is shown in Figure 5.

Figure 5: Existing 2018 Installed Capacity (MW) by Resource Type



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Several power plants have announced plans to retire one or more units. The table below lists the notable coal and natural gas planned retirements through 2030.

Table 8: Planned Coal and Natural Gas Retirements

Power Plant	Resource Type	Capacity (MW)
Boardman	Coal	522
Centralia	Coal	1,340
Colstrip 1 & 2	Coal	614
North Valmy	Coal	261
Naughton	Natural Gas	330

4.2.1 WIND AND SOLAR PROFILES

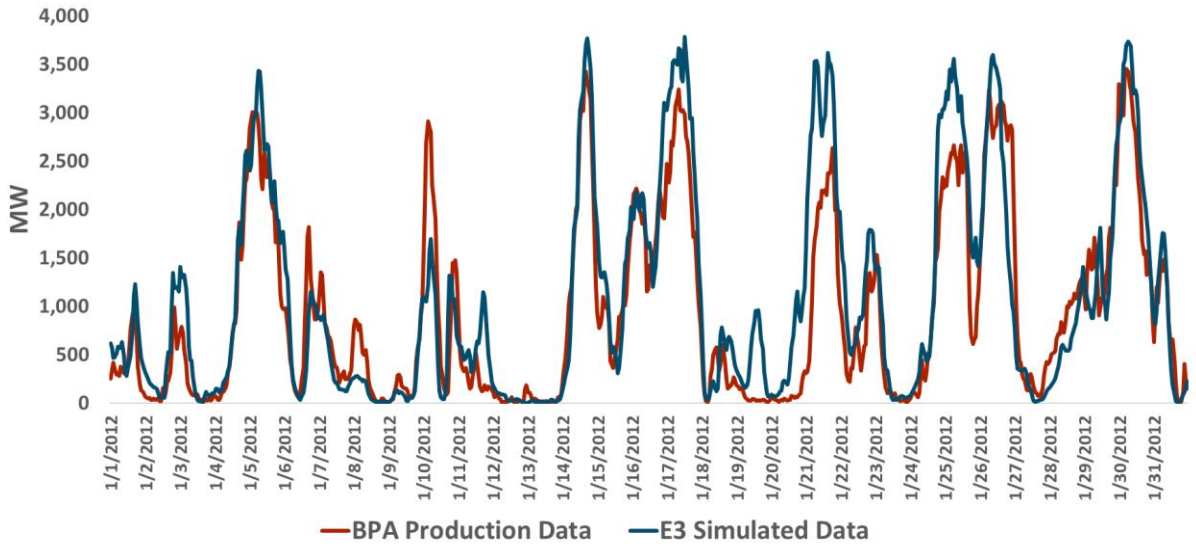
Hourly wind and solar data were collected for each existing resource in the combined dataset at the location of the resource. For wind, NREL's Wind Integration National Dataset Toolkit was used which includes historical hourly wind speed data from 2007-2012. For solar, NREL's Solar Prospector Database was used which includes historical hourly solar insolation data from 1998-2012. These hourly wind speeds and solar insolation values were then converted into power generation values using the NREL System Advisor Model (SAM) under assumptions for wind turbine characteristics (turbine power curve and hub height) and solar panel characteristics (solar inverter ratio). RECAP simulates future electricity generation from existing wind and solar resources using the historical wind speed data and solar insolation data respectively.

Simulated wind generation from existing wind plants within BPA territory was benchmarked to historical wind production data[13]. To simulate wind generation from existing plants accurately, wind turbine

[13] BPA publishes production from wind plants within its Balancing Authority Area in 5-min increments: https://transmission.bpa.gov/Business/Operations/Wind/default.aspx

technology (power curve and hub height) varies for each existing wind farm, based on the year of installation. Figure 6 shows how the simulated wind production compares to historical wind production in BPA territory in January 2012.

Figure 6: Comparison of historical wind generation to simulated wind production for January 2012



A detailed description of the renewable profile simulation process is described in Appendix C.

4.2.2 HYDRO

Hydro availability is based on a random distribution of the historical hydro record using the water years from 1929-2008. This data was obtained from the NWPCC's GENESYS model. Future electricity generation from existing hydro resources is simulated using the historical hydro availability. Available hydro energy is dispatched in RECAP subject to sustained peaking limits (1-hr, 2-hr, 4-hr, 10-hr) and minimum output levels. The sustained peaking limits are based on detailed hydrological models developed by NWPCC. Available hydro budgets, sustained peaking limits, and minimum output levels are shown for three hydro

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years – 1937 (critical hydro year), 1996 (high hydro year), and 2007 (typical hydro year). The 10-hour sustained peaking limits for each month represent the maximum average generation for any continuous 10-hour period within the month.

Figure 7: Monthly budgets, sustained peaking limits and minimum outputs levels for 1937 (critical hydro)

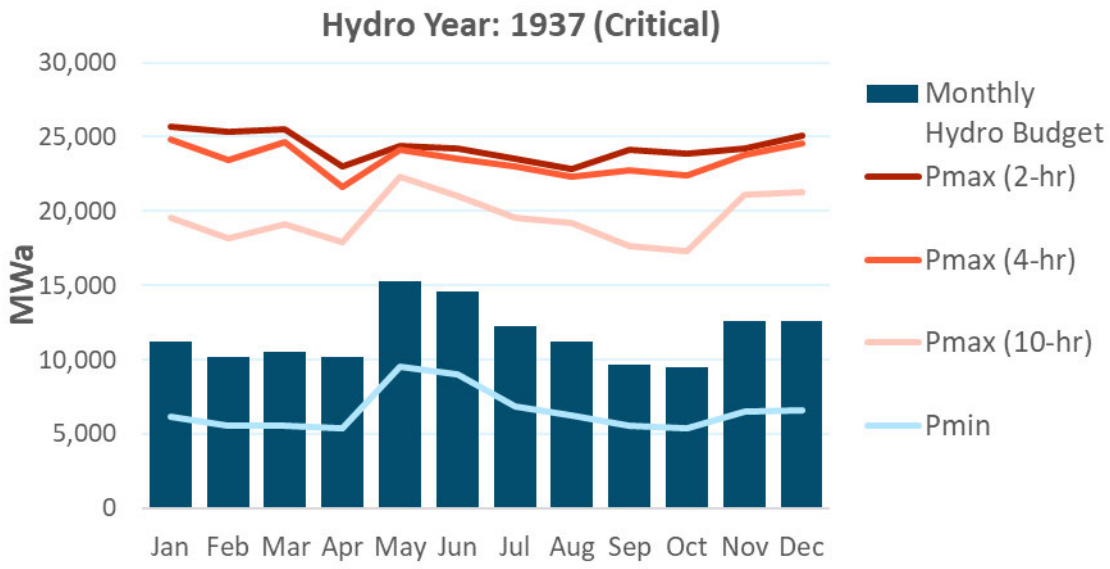


Figure 8: Monthly budgets, sustained peaking limits and minimum outputs levels for 1996 (high hydro)

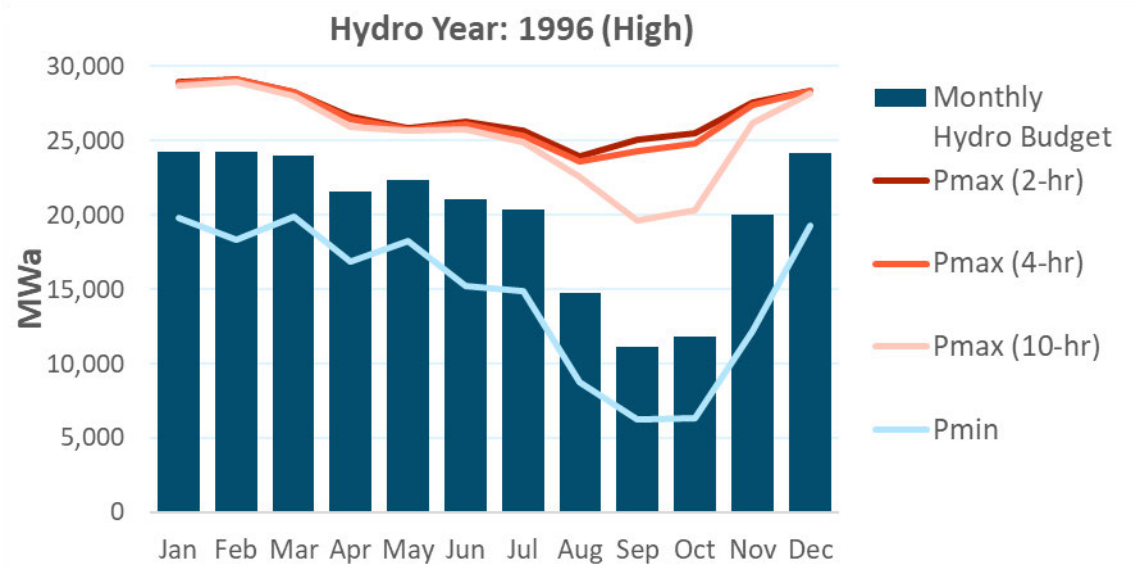
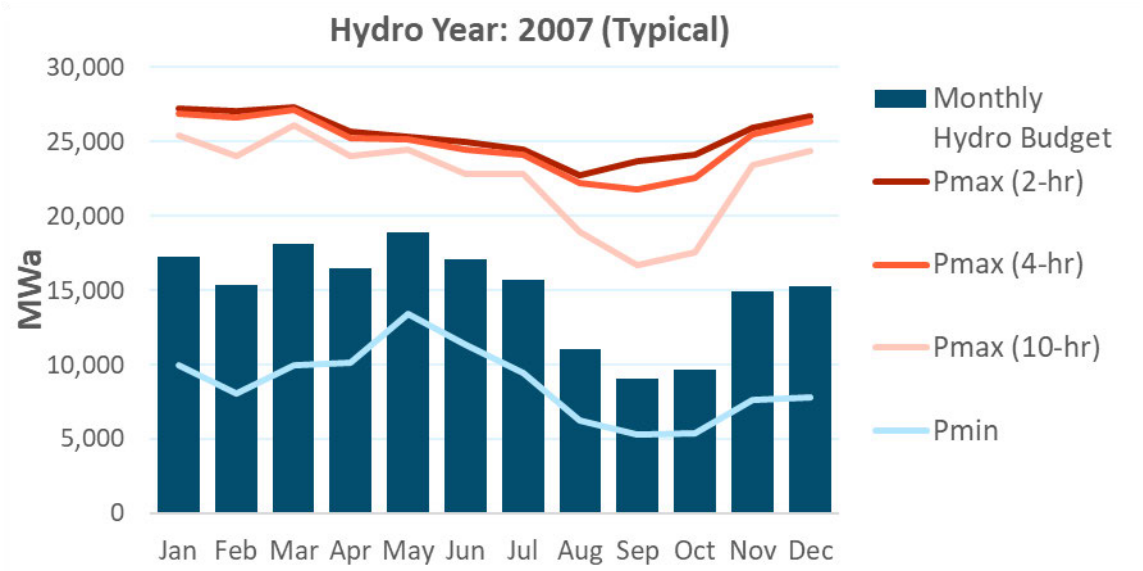


Figure 9: Monthly budgets, sustained peaking limits and minimum outputs levels for 2007 (typical hydro)



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4.2.3 IMPORTS/EXPORTS

The Greater Northwest region is treated as one zone within the model, but it does have the ability to import and export energy with neighboring regions, notably California, Canada, Rocky Mountains, and the Southwest. Import and export assumptions used in this model are consistent with the NWPCC's GENESYS model and are listed in Table 9. Monthly and hourly import availabilities are additive but in no hour can exceed the simultaneous import limit of 3,400 MW. In the 100% GHG Reduction scenarios, import availability is set to zero to prevent the region from relying on fossil fuel imports.

Table 9: Import Limits

Import Type	Availability	MW
Monthly Imports	Nov – Mar	2,500
	Oct	1,250
	Apr – Sep	-
Hourly Imports	HE 22 – HE 5	3,000
	HE 5 – HE 22	-
Simultaneous Import Limit	**All Hours**	**3,400**

For the purposes of calculating the CPS % metric i.e., "clean portfolio standard", the model assumes an instantaneous exports limit of 7,200 MW in all hours.

Table 10: Export Limit

Export Type	Availability	MW
Simultaneous Export Limit	**All Hours**	**7,200**

4.3 Candidate Resources

Candidate resources are used to develop portfolios of resources in 2050 to both achieve GHG reduction targets or ensure acceptable reliability of 2.4 hrs./yr. LOLE. For a more detailed description of the portfolio development process, see Section 3.1.3. The 7 candidate resources are:

- Solar (geographically diverse across Greater Northwest)
- Northwest Wind (WA/OR)
- Montana Wind
- Wyoming Wind
- 4-Hour Storage
- 8-Hour Storage
- 16-Hour Storage

Natural gas generation is also added as needed to meet any remaining reliability gaps after the GHG reduction target is met. The new renewable candidate resources (solar, NW wind, MT wind, WY wind) are assumed to be added proportionally across a geographically diverse footprint which has a strong impact on the ability of variable renewable resources to provide reliable power that can substitute for firm generation. Figure 10 illustrates the location of new candidate renewable resources. When a resource is added, it is added proportionally at each of the locations shown in the figure below.

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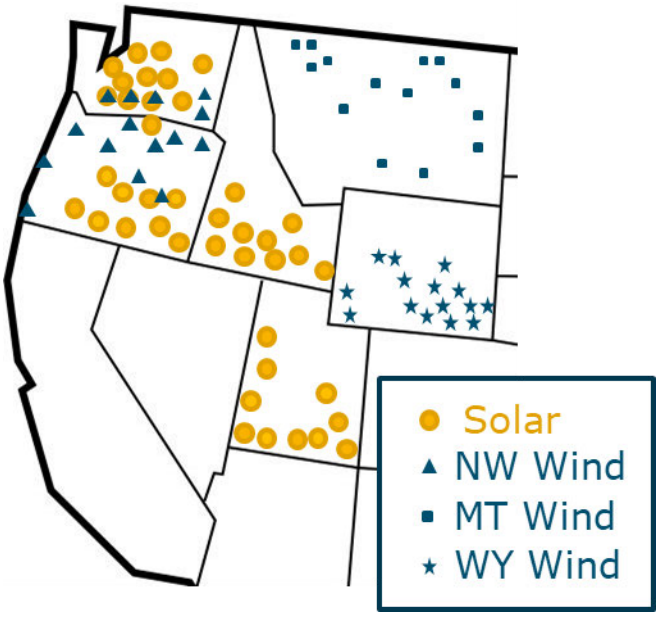
Figure 10: New Renewable Candidate Resources



The generation output profile for each location was simulated by gathering hourly wind speed and solar insolation data from NREL's Wind Integration National Dataset Toolkit and Solar Prospector Database and converting to power output using NREL's System Advisor Model. The wind profiles used in this study are based on 135 GW of underlying wind production data from hundreds of sites. The solar profiles used in this study are based on 80 GW of underlying solar production data across four states. This process is described in more detail in Appendix C.

New storage resources are available to the model in different increments of duration at different costs which provide different value in terms of both reliability and renewable integration for GHG reduction. Note that the model can choose different quantities of each storage duration which results in a fleet-wide storage duration that is different than any individual storage candidate resource. Because storage is modeled in terms of capacity charge/discharge and duration, many different storage technologies could provide this capability. The cost forecast trajectory for Li-Ion battery storage was used to estimate costs,

but any storage technology that could provide equivalent capacity and duration, such as pumped hydro or flow batteries, could substitute for the storage included in the portfolio results of this study.

New renewable portfolios are within the bounds of current technical potential estimates published in NREL.

Table 11. NREL Technical Potential (GW)

State	Wind Technical Potential (GW)
Washington	18
Oregon	27
Idaho	18
Montana	944
Wyoming	552
Utah	13
Total	**1,588**

4.3.1.1 Resource Costs

All costs in this study are presented in 2016 dollars. The average cost of each resource over the 2018-2050 timeframe is shown in Table 12 while the annual cost trajectories from 2018-2050 are shown in Figure 11.

Table 12. Resource Cost Assumptions (2016 $)

Technology	Unit	High[14]	Low[15]	Transmission	Notes
Solar PV	$/MWh	$59	$32	$8	Capacity factor = 27%
NW Wind	$/MWh	$55	$43	$6	Capacity factor = 37%
MT/WY Wind	$/MWh	$48	$37	$19	Capacity factor = 43%
4-hr Battery	$/kW-yr	$194	$97		

[14] Source for high prices: 2017 E3 PGP Decarbonization Study
[15] Source for low prices: NREL 2018 ATB Mid case for wind and solar; Lazard LCOS Mid case 4.0 for batteries

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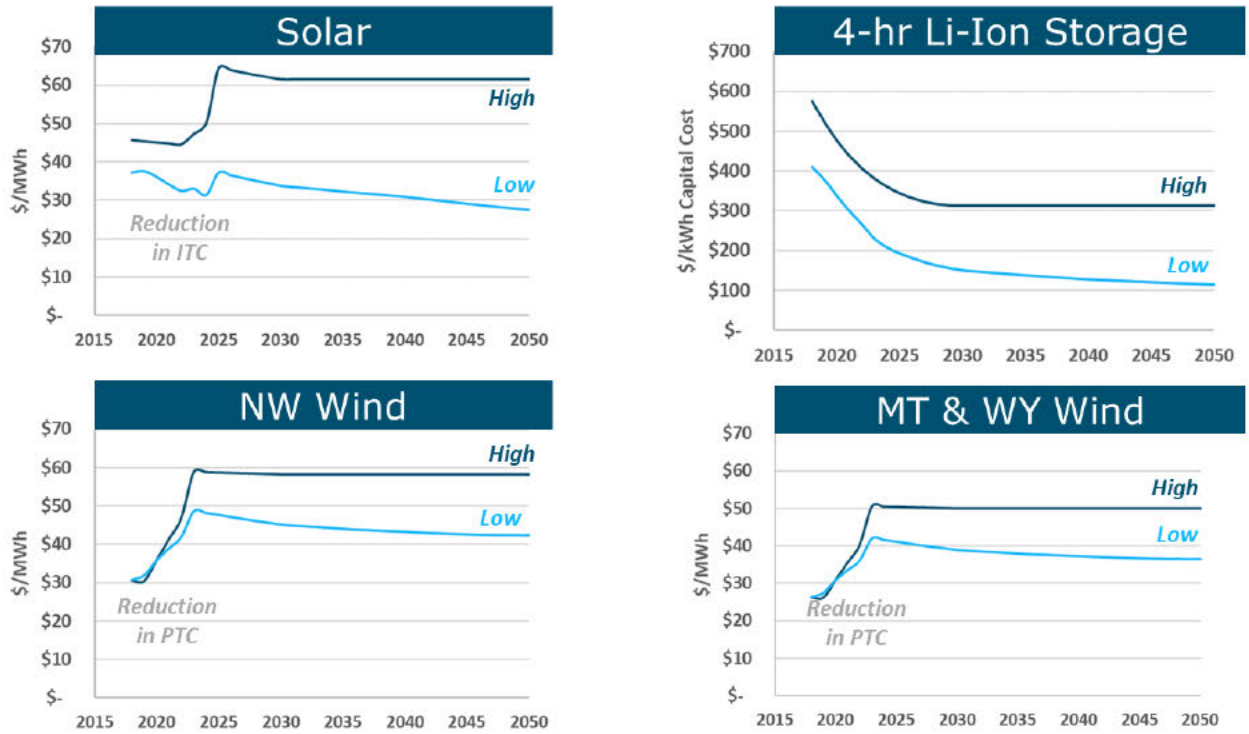
Technology	Unit	High[14]	Low[15]	Transmission	Notes
8-hr Battery	$/kW-yr	$358	$189		
16-hr Battery	$/kW-yr	$686	$373		
Natural Gas Capacity	$/kW-yr	$150	$150		7,000 Btu/kWh heat rate; $5/MWh variable O&M
Gas Price	$/MMBtu	$4	$2		
Biogas Price	$/MMBtu	$39	$39		

Figure 11: Cost trajectories over the 2018-2050 timeframe (2016 $)



4.4 Estimating Cost and GHG Metrics

The cost of the future electricity portfolios consists of (1) fixed capital costs for building new resources, and (2) operating costs for running both existing and new resources. For new wind and new solar resources, the cost of generation is calculated using their respective levelized costs (see Table 12). Cost of electricity generation from natural gas plants includes both the capital cost for new natural gas plants and the operating costs (fuel costs and variable operating costs). All the natural gas plants are assumed to operate at a heat rate of 7,000 Btu/kWh, with the price of natural gas varying from $2 to $4 per MMBtu (see Table 12). Storage resources are assumed to have only fixed cost, but no operating cost. All exports are assumed to yield revenues of $30 per MWh.

In this study, annual GHG emissions are compared against 1990 emission levels, when the emissions for the Greater Northwest region was 60 million metric tons. GHG emissions are calculated for each thermal resource depending on the fuel type. For natural gas plants, an emission rate of 117 lb. of CO_2 per MMBtu of natural gas is assumed, yielding 0.371 metric tons of CO_2 per MWh of electricity generated from natural gas (assumed 7,000 Btu/kWh heat rate). For coal plants, an emission rate of 1.0 ton of CO_2 per MWh of electricity generated from coal is assumed.

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5 Results

5.1 Short-Term Outlook (2018)

The 2018 system (today's system) in the study region is supplied by a mix of various resources, as described in Section 4.2. The annual electricity load for the study region is 247 TWh with a winter peak demand of 43 GW. Hydro energy provides the plurality of generation capacity with significant contributions from natural gas, coal and wind generation.

Resource adequacy conclusions vary depending on what metric is used for evaluation. The region has sufficient capacity to meet the current standard used by the NWPCC of 5% annual loss of load probability (LOLP). The region does not have sufficient capacity to meet the 2.4 hrs./yr. LOLE standard used in this study. In other words, most loss of load is concentrated in a few number of years which matches intuition for a system that is dependent upon the annual hydro cycle and susceptible to drought conditions. Full reliability statistics for the Greater Northwest region are shown in Table 13.

Table 13. 2018 Reliability Statistics

Metric	Units	Value
Annual LOLP (%)	%	3.7%
Loss of Load Expectation (LOLE)	hrs/yr	6.5
Expected Unserved Energy (EUE)	MWh/yr	5,777
Normalized EUE	%	0.003%
1-in-2 Peak Load	GW	43
PRM Requirement	% of peak	12%
Total Effective Capacity Requirement	GW	48

Table 14. 2018 Load and Resource Balance

Load			Load GW
Peak Load			42.1
Firm Exports			1.1
PRM (12%)			5.2
Total Requirement			**48.4**
Resources	**Nameplate GW**	**Effective %**	**Effective GW**
Coal	10.9	100%	10.9
Gas	12.2	100%	12.2
Biomass & Geothermal	0.6	100%	0.6
Nuclear	1.2	100%	1.2
Demand Response	0.6	50%	0.3
Hydro	35.2	53%	18.7
Wind	7.1	7%	0.5
Solar	1.6	12%	0.2
Storage	0	—	0
Total Internal Generation	**69.1**		**44.7**
Firm Imports	3.4	74%	2.5
Total Supply	**72.5**		**47.2**
Surplus/Deficit			
Capacity Surplus/Deficit			**-1.2**

In order to meet an LOLE target of 2.4 hrs./yr., a planning reserve margin (PRM) of 12% is required. The PRM is calculated by dividing the quantity of effective capacity needed to meet the LOLE target by the median peak load, then subtracting one. This result is lower than many individual utilities currently hold within the region (typical PRM ~15%) due to the load and resource diversity across the geographically large Greater Northwest region. As shown in Table 14, the total effective capacity (47 GW) available is slightly lower than the total capacity requirement (48 GW) which is consistent with the finding that the

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system is not sufficiently reliable to meet a 2.4 hrs./yr. LOLE target. The effective capacity percent contributions from wind and solar are shown to be 7% and 12%, respectively. These relatively low values stem primarily from the non-coincidence of wind and solar production during high load events in the Greater Northwest region, notably very cold winter mornings and evenings.

It should be noted that the effectiveness of firm capacity is set to 100% by convention in calculating a PRM. The contribution of variable resources is then measured relative to firm capacity, incorporating the effect of forced outage rates for firm resources.

5.2 Medium-Term Outlook (2030)

The Greater Northwest system in 2030 is examined under two scenarios:

+ **Reference**
    - Planned coal retirements; new gas gen for reliability
+ **No Coal**
    - All coal retired; new gas gen for reliability

The resulting generation portfolios in both scenarios (both of which meet the 2.4 hrs./yr. LOLE reliability standard) are shown in Figure 12 alongside the 2018 system for context. To account for the load growth by 2030, 5 GW of net new capacity is required to maintain reliability. In the *Reference* Scenario where 3 GW of coal is retired, 8 GW of new firm capacity is needed by 2030 for reliability. Similarly, the *No Coal* Scenario (where all 11 GW of coal is retired) results in 16 GW of new firm capacity need by 2030. The study assumes all the new capacity in the 2030 timeframe need is met through additional natural gas build. It should be noted that regardless of what resource mix is built to replace the retirement of coal, the siting, permitting, and construction of these new resources will take significant time so planning for

these resources needs to begin well before actual need. The portfolio tables for each scenario are summarized in Appendix A.2.

Figure 12: Generation Portfolios in 2030

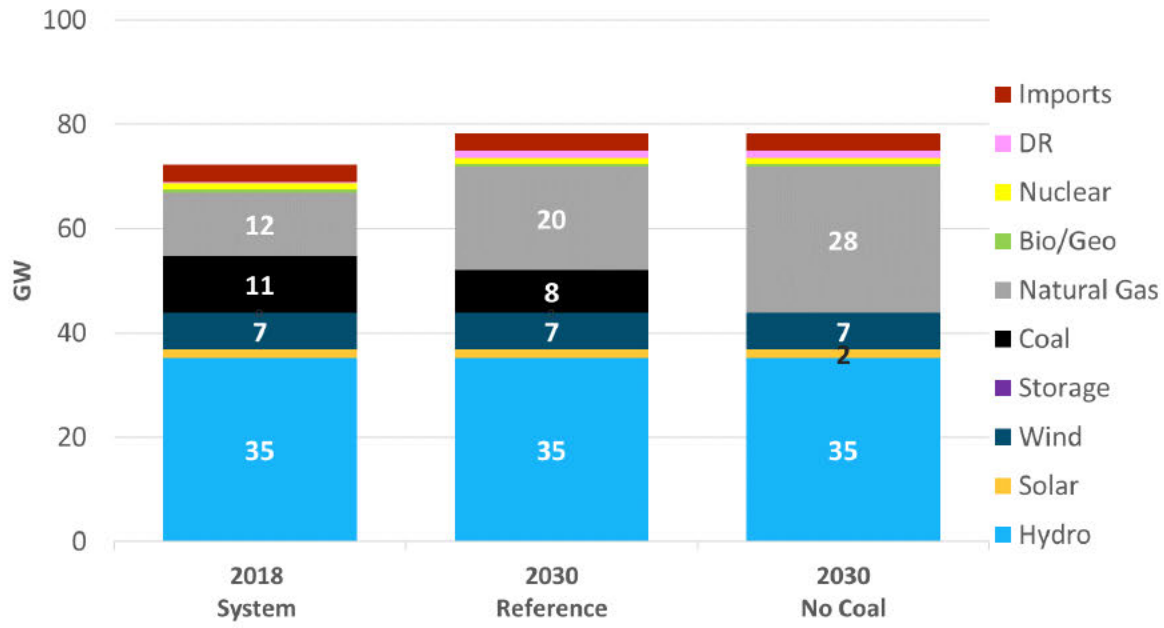

Table 15. 2030 Generation Portfolio: Key Metrics

Metric	2030 Reference	2030 No Coal
GHG-Free Generation (%)	61%	61%
GHG Emissions (MMT CO_2 / year)	67	42
% GHG Reduction from 1990 Level	-12%[16]	31%

[16] Negative value for %GHG reduction from 1990 level indicates that emissions are above 1990 level

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As these metrics show, without either natural gas replacement of coal capacity or significant increase in renewable energy, GHG emissions are forecasted to rise in the 2030 timeframe. However, repowering coal with natural gas has the potential to reduce GHG emissions by 31% below 1990 levels.

In order to meet an LOLE target of 2.4 hrs/yr, the region requires a planning reserve margin (PRM) in 2030 of 12%.

Table 16. 2030 Load and Resource Balance, Reference Scenario

Load			**Load MW**
Peak Load			45.9
Firm Exports			1.1
PRM (12%)			5.8
Total Requirement			**52.9**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	8.2	100%	8.2
Gas	19.9	100%	19.9
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	2.2	45%	1.0
Hydro	35.2	53%	18.7
Wind	7.1	9%	0.6
Solar	1.6	14%	0.2
Storage	0	—	0
Total Internal Generation	**76.1**		**50.5**
Firm Imports	3.4	74%	2.5
Total Supply	**79.5**		**52.9**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

5.3 Long-Term Outlook (2050)

The Greater Northwest system in 2050 is examined under a range of decarbonization scenarios, relative to 1990 emissions.

- 60% GHG Reduction
- 80% GHG Reduction
- 90% GHG Reduction
- 98% GHG Reduction
- 100% GHG Reduction

The portfolio for each decarbonization scenario was developed using the methodology described in Section 3.1.3. To summarize this process, RECAP iteratively adds carbon-free resources (wind, solar storage) to reduce GHG in a manner that maximizes the effective capacity of these carbon-free resources, thus minimizing the residual need for firm natural gas capacity. Once a cost-effective portfolio of carbon-free resources has been added to ensure requisite GHG reductions, the residual need for natural gas generation capacity is calculated to ensure the entire portfolio meets a 2.4 hrs./yr. LOLE standard.

5.3.1 ELECTRICITY GENERATION PORTFOLIOS

All the 2050 decarbonization portfolios are shown together in Figure 13. Higher quantities of renewable and energy storage are required to achieve deeper levels of decarbonization, which in turn provide effective capacity to the system and allow for a reduction in residual firm natural gas capacity need, relative to the reference case. Detailed portfolio results tables for each scenario are provided in Appendix A.2.

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Figure 13: Generation Portfolios for 2050 Scenarios

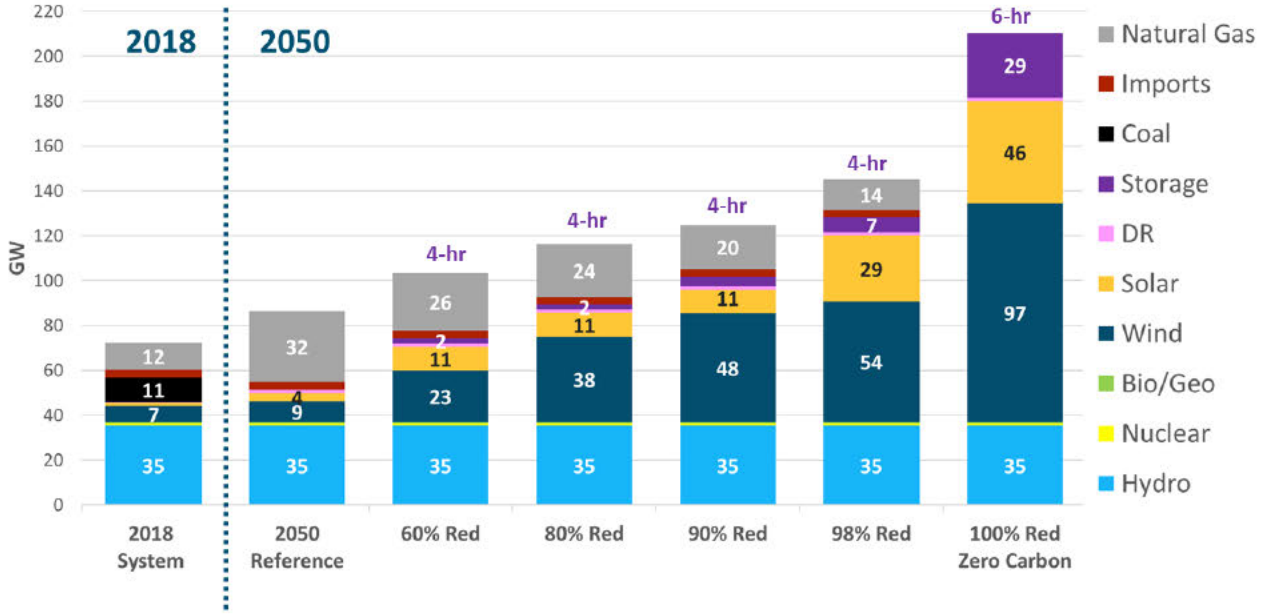

Table 17. 2050 Decarbonization Scenarios: Key Generation Metrics

Metric	Units	Reference Scenario	GHG Reduction Scenarios				
			60% Red.	80% Red.	90% Red.	98% Red.	100% Red.
GHG Emissions	MMT/yr	50	25	12	6	1	0
GHG Reductions	% below 1990	16%	60%	80%	90%	98%	100%
GHG-Free Generation	% of load	60%	80%	90%	95%	99%	100%
Clean Portfolio Standard	% of sales	63%	86%	100%	108%	117%	123%
Annual Renewable Curtailment	% of potential	Low	Low	4%	10%	21%	47%

Table 17 evaluates the performance of each decarbonization portfolio along several key generation metrics that were described in detail in Section 3.4.

Analyzing the portfolio of each decarbonization scenario and resulting performance metrics yields several interesting observations.

- On retiring all 11 GW of coal by 2050 in the *Reference* scenario, the Greater Northwest system requires 20 GW of new capacity in order to meet the 2.4 hrs./yr. LOLE standard used in the study. This suggests that 9 GW of net new firm capacity is needed to account for load growth through 2050.
- The integration of more renewables and conservation policies provides the energy needed to serve loads in a deeply decarbonized future, but new gas-fired generation capacity is needed for relatively short, multi-day events with low renewable generation, high loads, and low hydro availability.
- To reduce GHG emissions to 80% below 1990 levels, RECAP chooses to build 38 GW of wind, 11 GW of solar, and 2 GW of 4-hour storage. In addition to this renewable build, 12 GW of new firm capacity is required for reliability (after retaining all the existing natural gas plants) which is assumed to be met through natural gas build. The generation portfolio under 80% Reduction Scenario results in a 100% clean portfolio standard and 90% GHG-free generation.
- RECAP achieves deeper levels of decarbonization (GHG emissions 98% below 1990 level down to 1.0 MMT GHG/yr) by overbuilding renewables with 54 GW of wind, 29 GW of solar, and 7 GW of 4-hour storage. Annual renewable oversupply becomes significant (at 21%). Nevertheless, the system still requires an additional gas build of 2 GW after retaining all existing natural gas plants, to ensure reliability during periods of low renewable generation. The capacity factor for these gas plants is extremely low (3%), underlining their importance for reliability.
- The 100% GHG Reduction Scenario (Zero Carbon Scenario) results in no GHG emissions from the electricity sector. The generation portfolio consists only of renewables (97 GW of wind and 46 GW of solar) and energy storage (29 GW of 6-hour storage). Ensuring a reliable system using only renewables and energy storage requires a significant amount of renewable overbuild – resulting

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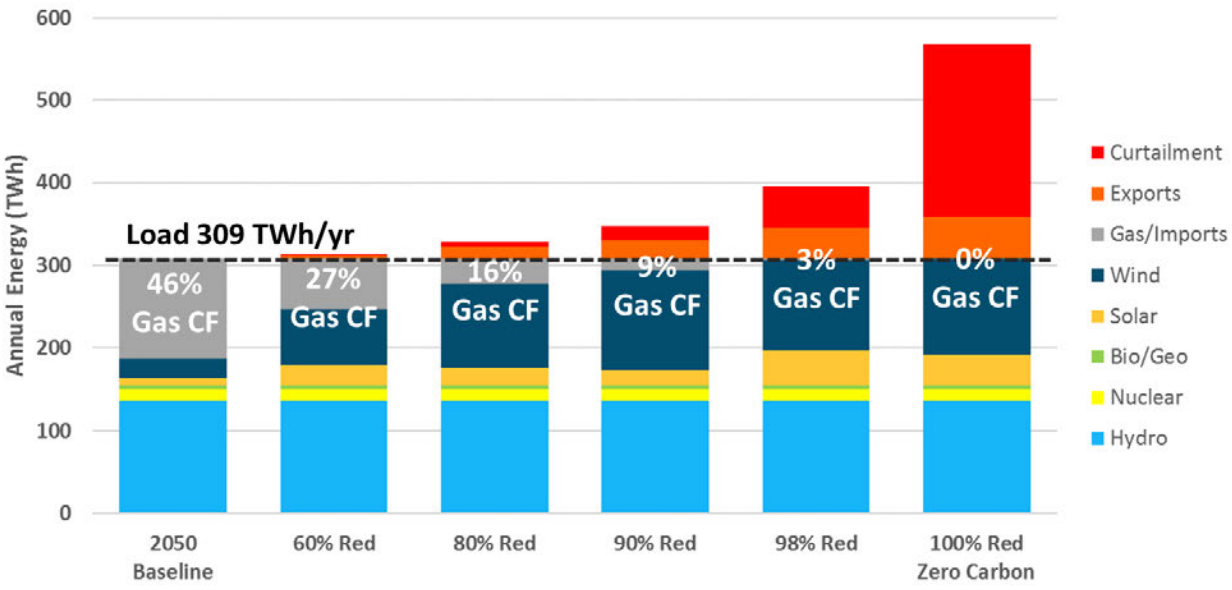
in nearly half of all the generated renewable energy to be curtailed. Compared to the 98% GHG Reduction Scenario (which results in 99% GHG-free generation), the Zero Carbon Scenario requires almost double the quantity of renewables and even greater quantity of energy storage.

With increases in renewable generation, generation from natural gas plants decreases. Due to negligible operating costs associated with renewable production, it is cost optimal to use as much renewable generation as the system can. During periods of prolonged low renewable generation when energy storage is depleted, natural gas plants can ramp up to provide the required firm capacity to avoid loss-of-load events. In the deep decarbonization scenarios, gas is utilized sparingly and even results in very low capacity factors (such as 9% and 3%). However, RECAP chooses to retain (and even build) natural gas as the most cost-effective resource to provide reliable firm capacity. Renewable overbuild also results in significant amounts of curtailment.

Figure 14: Annual generation mix across the scenarios



A planning reserve margin of 7% to 9% is required to meet the 1-in-10 reliability standard in 2050 depending on the scenario. Accounting for a planning reserve margin, the total capacity requirement (load plus planning reserve margin) in 2050 is 57-59 GW. As shown in Table 18, this capacity requirement is met through a diverse mix of resources. Variable or energy-limited resources such as hydro, wind, solar and storage contribute only a portion of their entire nameplate capacity (ELCC) towards resource adequacy. Load and resource tables for the 80% and 100% Reduction scenarios are shown below.

Table 18. 2050 Load and Resource Balance, 80% Reduction scenario

Load			**Load MW**
Peak Load			52.8
Firm Exports			1.1
PRM (9%)			4.9
Total Requirement			**58.8**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	0	—	0
Gas	23.5	100%	23.5
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	5.5	29%	1.6
Hydro	35.2	53%	18.7
Wind	38.0	19%	7.2
Solar	10.6	19%	2.0
Storage	2.2	73%	1.6
Total Internal Generation	**116.8**		**56.3**
Firm Imports	3.4	74%	2.5
Total Supply	**120.2**		**58.8**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

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Table 19. 2050 Load and Resource Balance, 100% Reduction scenario

Load			Load MW
Peak Load			52.8
Firm Exports			1.1
PRM (7%)			4.0
Total Requirement			**58.0**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	0	—	0
Gas	0	—	0
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	5.5	29%	1.6
Hydro	35.2	57%	20.1
Wind	97.4	22%	21.5
Solar	45.6	16%	7.3
Storage	28.7	20%	5.7
Total Internal Generation	**214.2**		**58.0**
Firm Imports	0	—	0
Total Supply	**214.2**		**58.0**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

5.3.2 ELECTRIC SYSTEM COSTS

System costs are estimated using the methodology and cost assumptions described in Section 4.3.1.1 and Section 4.4. Electric system costs represent the cost of decarbonization relative to the 2050 *Reference* scenario, and so by definition all annual and unit cost increases in this scenario are zero. The 2050 *Reference* scenario does require significant investment in new resources in order to reliably meet load growth and existing RPS policy targets, so the zero incremental cost is not meant to make any assessment on the absolute change (or lack thereof) in total electric system costs or rates by 2050.

Table 20 evaluates the performance of 2050 decarbonization scenarios along two cost metrics for both a low and high set of cost assumptions.

Table 20: 2050 Decarbonization Scenarios: Key Cost Metrics

Metric		Units	Reference Scenario	GHG Reduction Scenarios				
				60% Red.	80% Red.	90% Red.	98% Red.	100% Red.
Annual Cost Increase	Lo	$BB/yr *(vs. Ref)*	—	$0	$1	$2	$3	$16
	Hi			$2	$4	$5	$9	$28
Unit Cost Increase	Lo	$/MWh *(vs. Ref)*	—	$0	$3	$5	$10	$52
	Hi			$7	$14	$18	$28	$89

Analyzing the cost results for each decarbonization scenario yields several interesting observations

+ To reduce GHG emissions to 80% below 1990 levels, a portfolio of wind/solar/storage can be obtained at an additional annual cost of $1 to $4 billion ($3 to $14/MWh) after accounting for the avoided costs of new gas build and utilization. Assuming an existing average retail rate of $0.10/kWh, this implies an increase of 3%-14% in real terms relative to the *Reference* Scenario. Because the 80% reduction scenario achieves a 100% clean portfolio standard (as shown in Section 5.3.1), this scenario is compelling from both a policy perspective and a cost perspective in balancing multiple objectives across the Greater Northwest region.

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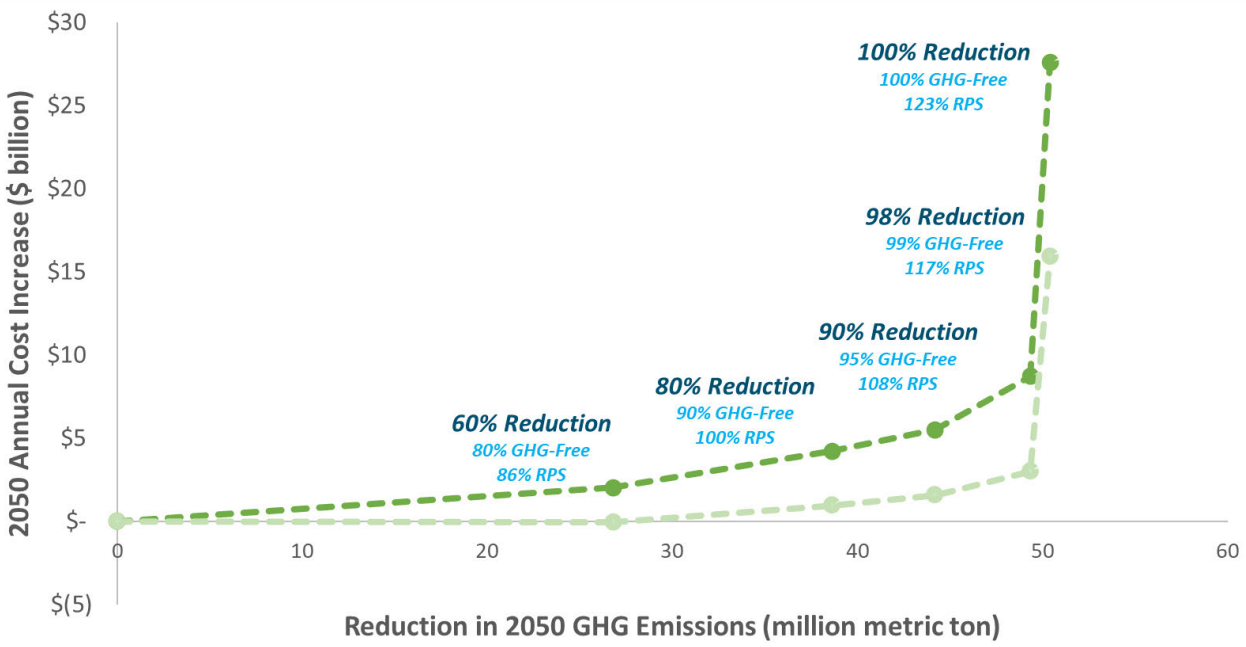
- Deep decarbonization (GHG emissions 98% below 1990 level down to 1.0 MMT GHG/yr) of the Greater Northwest system can be obtained at an additional annual cost of $3 to $9 billion ($10 to $28/MWh), i.e., the average retail rates increase 10%-28% in real terms relative to the *Reference* Scenario. This suggests that deep decarbonization of the Greater Northwest system can be achieved at moderate additional costs, assuming that natural gas capacity is available as a resource option to maintain reliability during prolonged periods of low renewable production.
- The 100% GHG Reduction Scenario requires a significant increase in wind, solar and storage to eliminate the final 1% of GHG-emitting generation. An additional upfront investment of $100 billion to $170 billion is required, relative to the 98% GHG Reduction scenario. Compared to the *Reference* Scenario, the Zero Carbon Scenario requires an additional annual cost of $16 to $28 billion ($52 to $89/MWh), i.e., the average retail rates nearly double.

Costs for individual utilities will vary and may be higher or lower than the region as a whole. This report does not address allocation of cost between utilities.

As shown in Figure 15, the cost increases of achieving deeper levels of decarbonization become increasingly large as GHG emissions approach zero. This is primarily due to the level of renewable overbuild that is required to ensure reliability and the increasing quantities of energy storage required to integrate the renewable energy.

Figure 15: Cost of GHG reduction



The marginal cost of GHG reduction represents the incremental cost of additional GHG reductions at various levels of decarbonization. Figure 16 and Figure 17 both show the increasing marginal cost of GHG abatement at each level of decarbonization. At very deep levels of GHG reductions, the marginal cost of carbon abatement greatly exceeds the societal cost of carbon emissions, which generally ranges from $50/ton to $250/ton[17], although some academic estimates range up to $800/ton[18].

[17] https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html
[18] https://www.nature.com/articles/s41558-018-0282-y

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Figure 16: Marginal Cost of GHG Reduction: 60% Reduction To 98% Reduction

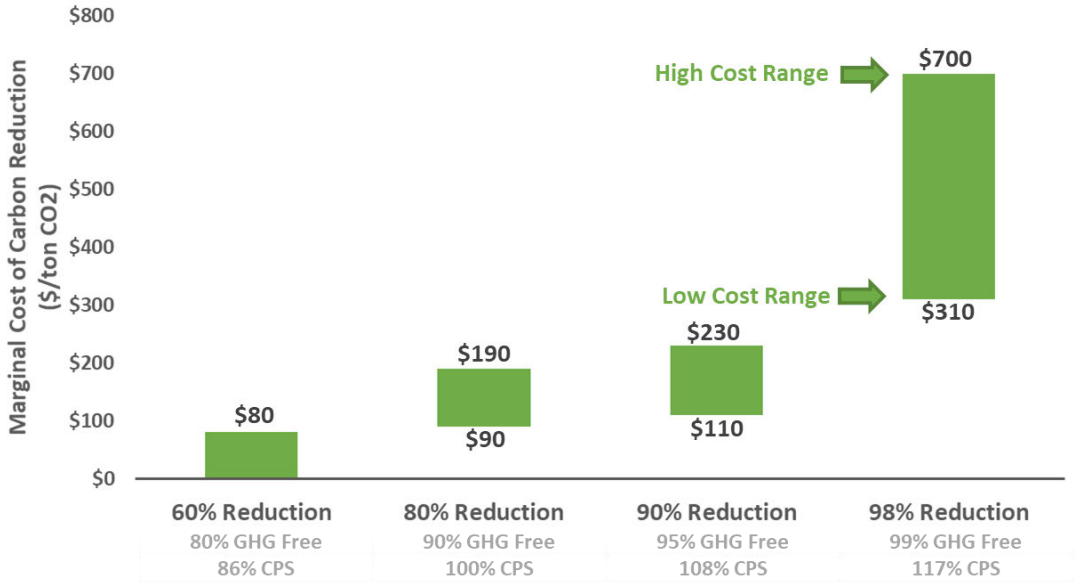
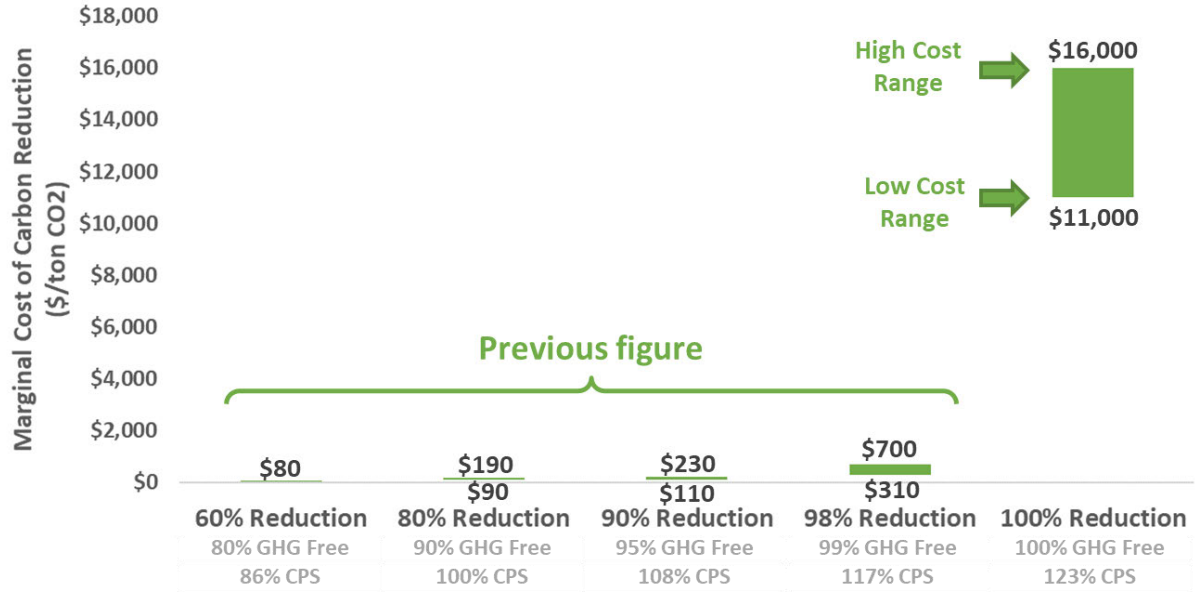


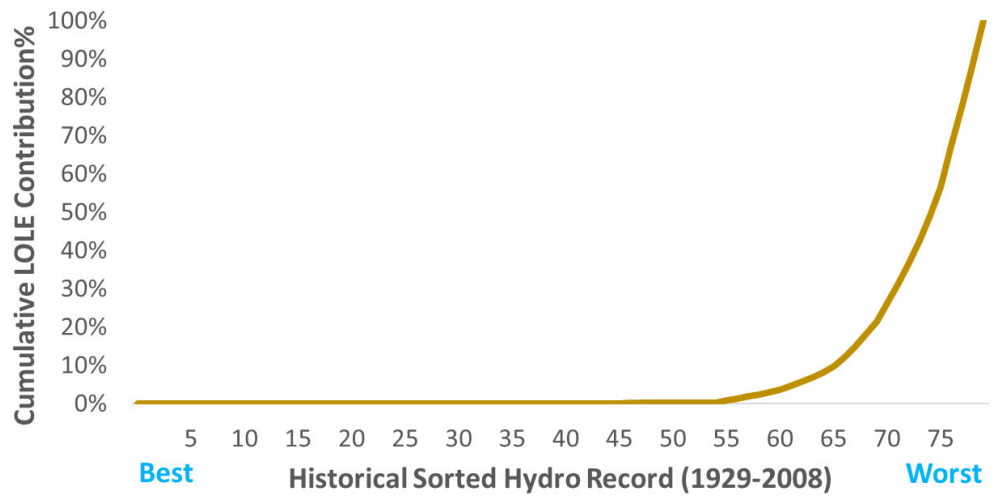
Figure 17: Marginal Cost of GHG Reduction: 60% Reduction to 100% Reduction



5.3.3 DRIVERS OF RELIABILITY CHALLENGES

The major drivers of loss of load in the Greater Northwest system include high load events, prolonged low renewable generation events, and drought hydro conditions. In today's system where most generation is dispatchable, prolonged low renewable generation events do not constitute a large cause of loss-of-load events. Rather, the largest cause of loss-of-load events stem from the combination of high load events and drought hydro conditions. This relationship between contribution to LOLE and hydro conditions is highlighted in Figure 18 which shows nearly all loss of load events concentrated in the worst 25% of hydro years.

Figure 18. 2018 System Loss-of-Load Under Various Hydro Conditions



At very high renewable penetrations, in contrast, prolonged low renewable generation events usurp drought hydro conditions as the primary driver of reliability challenges. Figure 19 shows that at high levels of GHG reductions, loss-of-load is much less concentrated in the worst hydro years as prolonged low renewable generation events can create loss-of-load conditions in any year.

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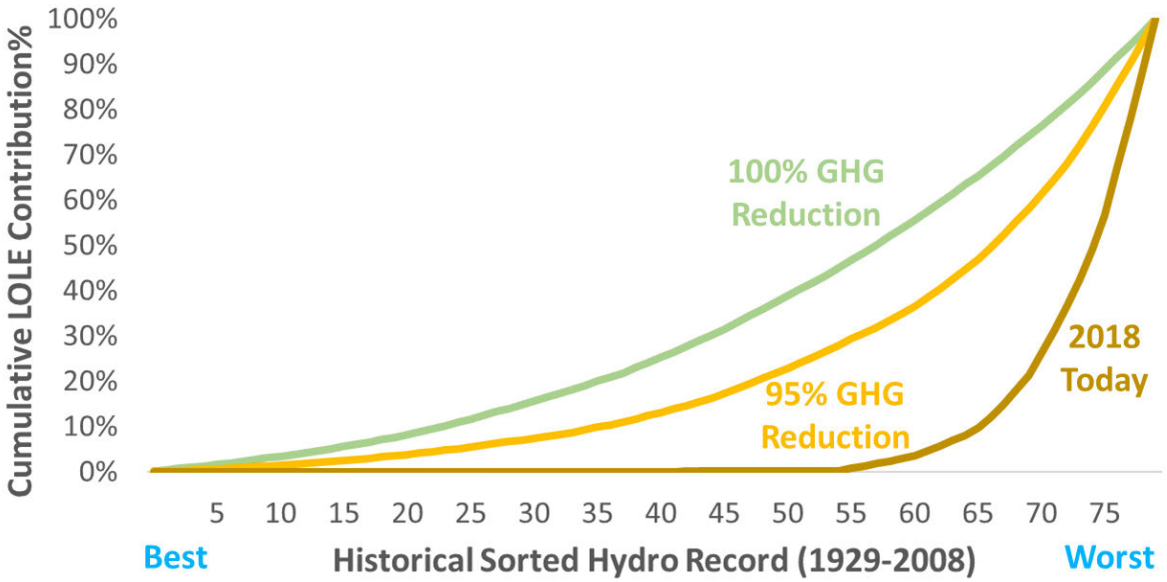
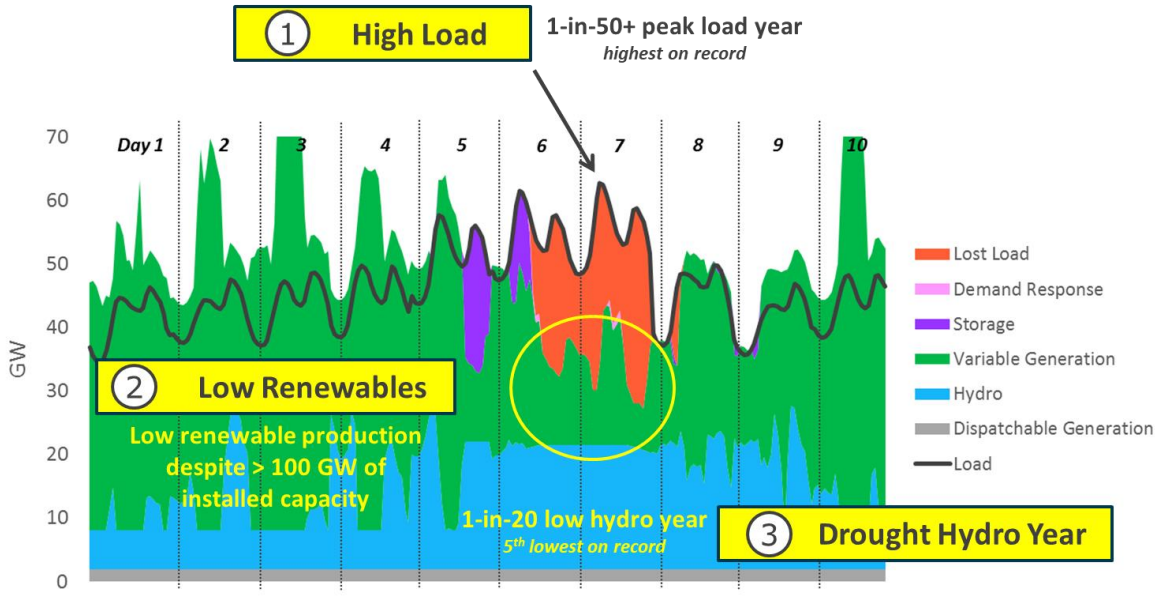
Figure 19. 2018 System GHG Reduction Scenarios Loss-of-Load Under Various Hydro Conditions



In practice, these prolonged periods of low renewable output manifest via multi-day winter storms that inhibit solar production over very wide geographic areas or large-scale high-pressure systems associated with low wind output. Figure 20 presents an example of multiday loss-of-load in a sample week in 2050 in the 100% GHG Reduction scenario. In a system without available dispatchable resources to call during such events, low solar radiation and wind speed can often give rise to severe loss-of-load events, especially when renewable generation may be insufficient to serve all load and storage quickly depletes. As shown in the example, over 100 GW of total installed renewables can only produce less than 10 GW of output in some hours. It is the confluence of events like these that drive the need for renewable overbuild to mitigate these events, which in turn leads to the very high costs associated with ultra-deep decarbonization.

Figure 20: Loss-of-load Example in a Sample Week



5.3.4 ROLE OF NATURAL GAS GENERATION CAPACITY

The significant buildout of renewables and storage to meet decarbonization targets contributes to the resource adequacy needs of the system and reduces the need for thermal generation. However, despite the very large quantities of storage and renewables in all the high GHG reduction scenarios, a significant amount of natural gas capacity is still needed for reliability (except for the 100% GHG Reduction scenario where natural gas combustion is prohibited). Even though the system retains significant quantities of gas generation capacity for reliability, the capacity factor utilization of the gas fleet decreases substantially at higher levels of GHG reductions as illustrated in Figure 21. It is noteworthy that all scenarios except 100% GHG reductions require more gas capacity than exists in 2018, assuming all coal (11 GW) is retired.

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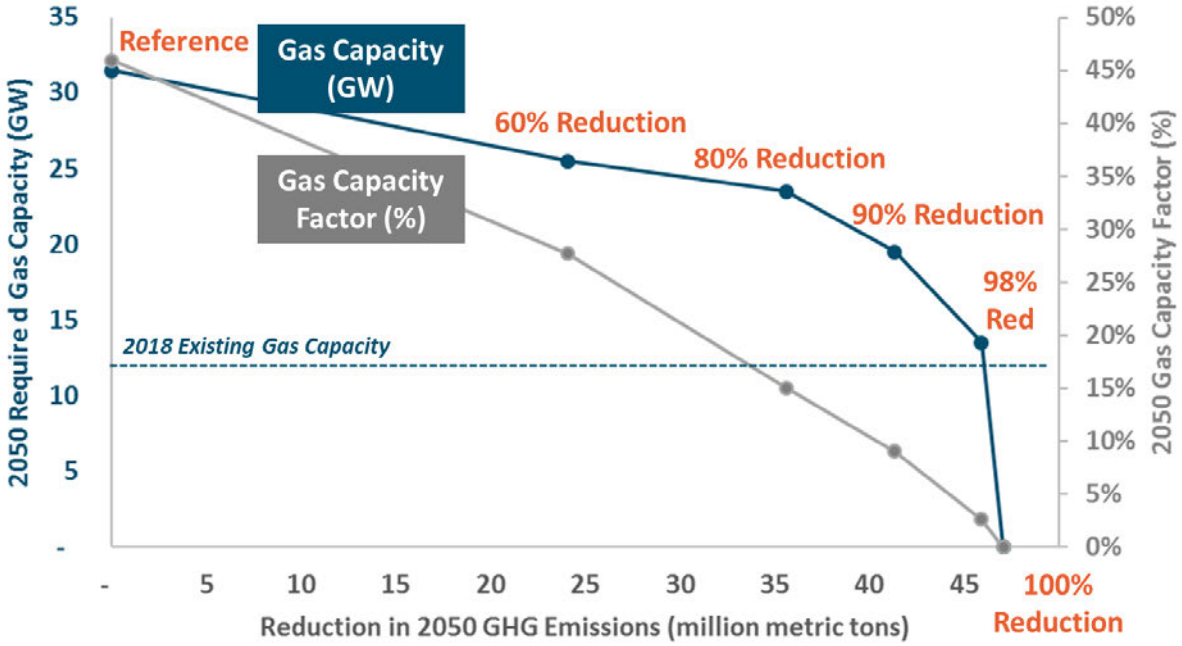
Figure 21: Natural Gas Required Capacity in Different 2050 Scenarios



5.3.5 EFFECTIVE LOAD CARRYING CAPABILITY

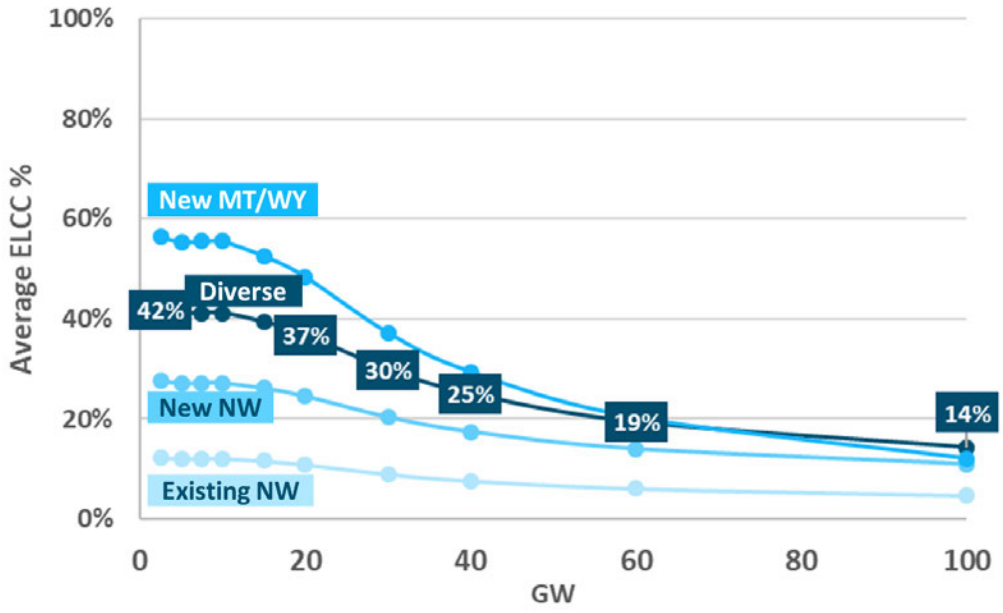
Effective Load Carrying Capability (ELCC) is a metric used in the electricity industry to quantify the additional load that can be met by an incremental generator while maintaining the same level of system reliability. Equivalently, ELCC is a measure of 'perfect capacity' that could be replaced or avoided with dispatch-limited resources such as wind, solar, storage, or demand response.

5.3.5.1 Wind ELCC

Wind resources in this study are grouped and represented as existing Northwest (Oregon and Washington) wind, new Northwest wind, and new Wyoming and Montana wind. The ELCC curves of each

representative wind resource and as well as the combination of all three resources (i.e., "Diverse") are shown in Figure 22.

Figure 22: Wind ELCC at Various Penetrations



These results are primarily driven by the coincidence of wind production and high load events. Existing wind in the Northwest today, primarily in the Columbia River Gorge, has a strong negative correlation with peak load events that are driven by low pressures and cold temperatures. Conversely, Montana and Wyoming wind does not exhibit this same correlation and many of the highest load hours are positively correlated with high wind output as illustrated in Figure 23.

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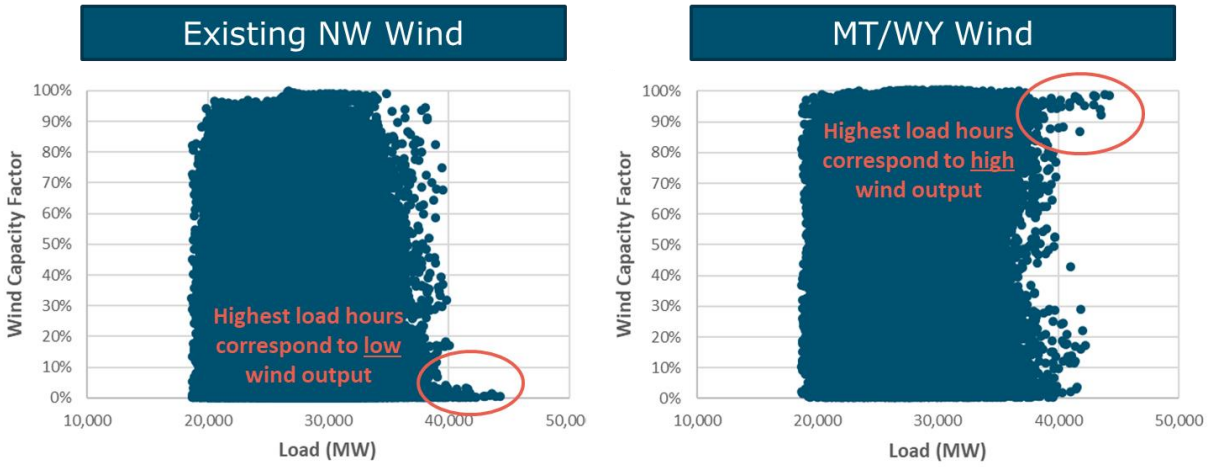
Figure 23: Load and Wind Correlation (Existing NW Wind and New MT/WY Wind)



Comparing and contrasting the ELCC of different wind resources yields several interesting findings:

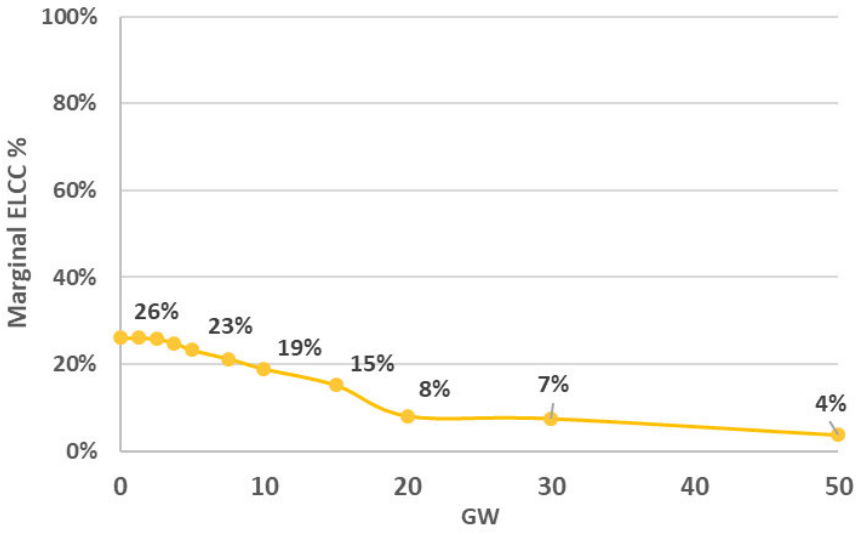
- The wide discrepancy between the "worst" wind resource (existing NW) and the "best" wind resource (new MT/WY) is primarily driven by the correlation of the wind production and peak load events in Washington and Oregon. Existing NW wind is almost entirely located within the Columbia River Gorge which tends to have very low wind output during the high-pressure weather systems associated with the Greater Northwest cold snaps that drive peak load events. Conversely, MY/WY wind is much less affected by this phenomenon due largely to geographic distance, and wind output tends to be highest during the winter months when the Northwest is most likely to experience peak load events.
- All wind resources experience significant diminishing returns at high levels of penetration. While wind may generate significant energy during the system peak, ultimately the net load peak that drives ELCC will shift to an hour with low wind production and reduce the effectiveness with which wind can provide ELCC. Diversity mitigates the rate of decline of ELCC.
- New NW wind has notably higher ELCC values than existing NW wind due to both improvements in turbine technology but also through larger geographic diversity of wind development within the Northwest region but outside of the Columbia River Gorge.

+ Diverse wind (combination of all three wind groups) yields the highest ELCC values at high penetrations. This is because even the best wind resources experience periods of low production and additional geographic diversity can help to mitigate these events and improve ELCC.

5.3.5.2 Solar ELCC

Solar resources in this study are grouped and represented as existing solar and new solar which is built across the geographically diverse area of Idaho, Washington, Oregon, and Utah. In general, solar provides lower capacity value than wind due to the negative correlation between winter peak load events and solar generation which tends to be highest in the summer. Like wind, solar ELCC also diminishes as more capacity is added. Figure 24 shows this information for the ELCC of new solar in the Greater Northwest region.

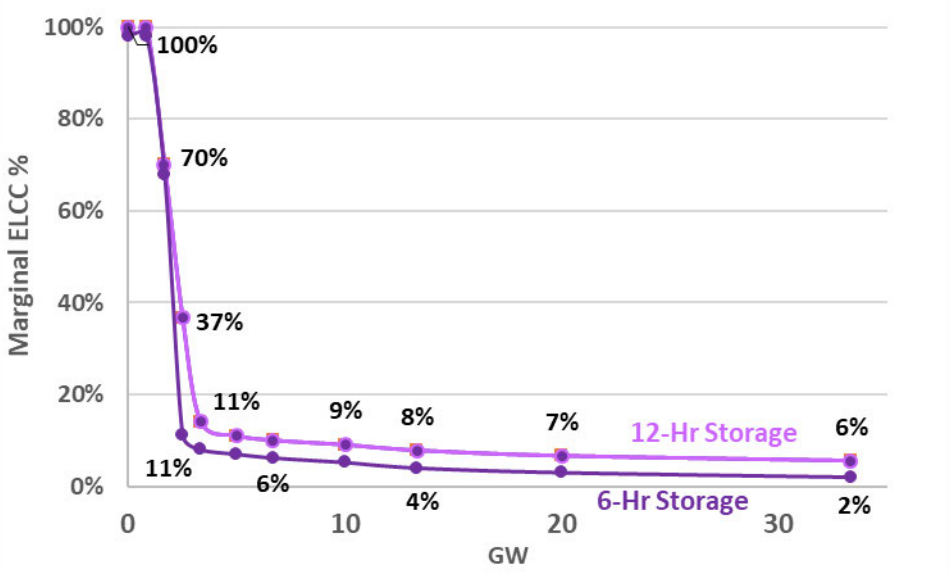
Figure 24: Solar ELCC at Various Penetrations



5.3.5.3 Storage ELCC

At small initial penetrations, energy storage can provide nearly 100% ELCC as a substitute for peaking generation that only needs to discharge for a small number of hours. However, at higher penetrations, the required duration for storage to continue to provide ELCC to the system diminishes significantly. This is primarily due to the fact that storage does not generate energy and ELCC is a measure of perfect capacity which can reliably generate energy. This result holds true for both shorter duration (6-hr) and longer duration (12-hr) storage which represents the upper end of duration for commercially available storage technologies. Figure 25 highlights the steep diminishing returns of storage toward ELCC.

Figure 25: Storage ELCC at Various Penetrations



This steeply-declining ELCC value for diurnal energy storage is particularly acute in the Pacific Northwest. This has to do with the fact that there is a significant quantity of energy storage implicit with the 35-GW hydro system in the region. The Federal Columbia River Power System is already optimized over multiple days, weeks and months within the bounds of non-power constraints such as flood control, navigation

and fish & wildlife protections. Significant quantities of energy are stored in hydroelectric reservoirs today and dispatched when needed to meet peak loads. Thus, additional energy storage has less value for providing resource adequacy in the Northwest than it does in regions that have little or no energy storage today.

5.3.5.4 Demand Response ELCC

Demand response (DR) represents a resource where the system operator can call on certain customers during times of system stress to reduce their load and prevent system-wide loss-of-load events. However, DR programs have limitations on how often they can be called and how long participants respond when they are called. DR in this study is represented as having a maximum of 10 calls per year with each call lasting a maximum of 4 hours. This is a relatively standard format for DR programs, although practice varies widely across the country. This study also assumes perfect foresight of the system operator such that a DR call is never "wasted" when it wasn't actually needed for system reliability.

Figure 26: Cumulative and Marginal ELCC of DR

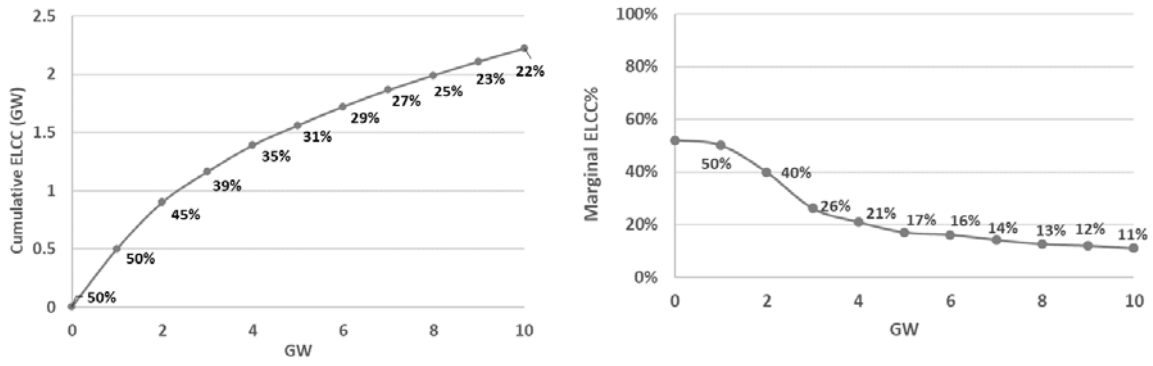


Figure 26 shows the cumulative and marginal ELCC of DR at increasing levels of penetration. Due to the limitations on the number of calls and duration of each call, DR has an initial ELCC of approximately 50%. Similar to energy storage, conventional 4-hour DR has less value in the Pacific Northwest than in other

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regions due to the flexibility inherent in the hydro system. Also, the capacity value of DR declines as the need for duration becomes longer and longer.

5.3.5.5 ELCC Portfolio Effects

Grouping different types of renewable resources, energy storage, and DR together often creates synergies between the different resources such that the combined ELCC of the entire portfolio is more than the sum of any resource's individual contribution. For example, solar generation can provide the energy that storage needs to be effective and storage can provide the on-demand dispatchability that solar needs to be effective. This resulting increase in ELCC is referred to as the diversity benefit.

Figure 27 shows the average ELCC for each resource type both on a stand-alone basis and also with a diversity allocation that accrues to each resource when they are added to a portfolio together.

Figure 27: ELCC of Solar, Wind, and Storage with Diversity Benefits

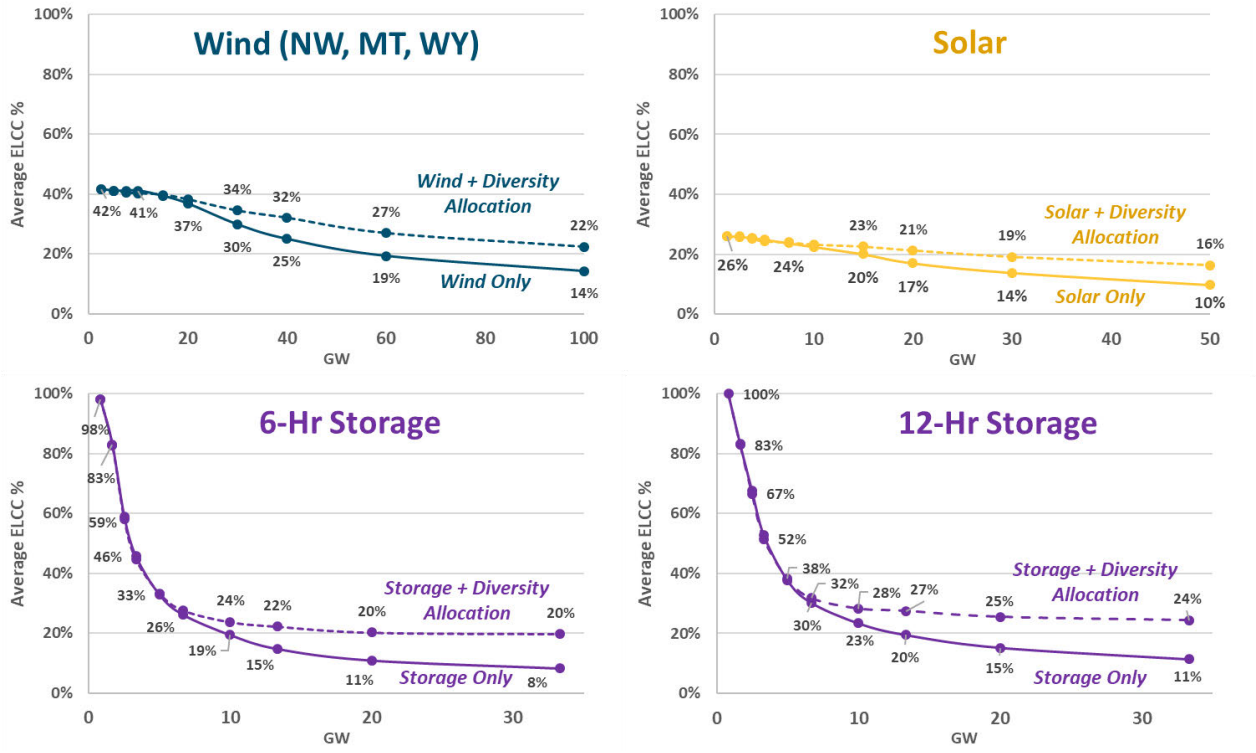

Figure 28 presents the cumulative portfolio ELCC of wind, solar, and storage up to the penetrations required to reliably serve load in a 100% GHG Reduction scenario. At high penetrations of renewables and storage, most of the ELCC is realized through diversity, although it still requires approximately 170 GW of nameplate renewable and storage resources to provide an equivalent of 37 GW of firm ELCC capacity that is required to retire all fossil generation. However, unlike adding these resources on a standalone basis, a combined portfolio continues to provide incremental ELCC value of approximately 20% of nameplate even at very high levels of penetration.

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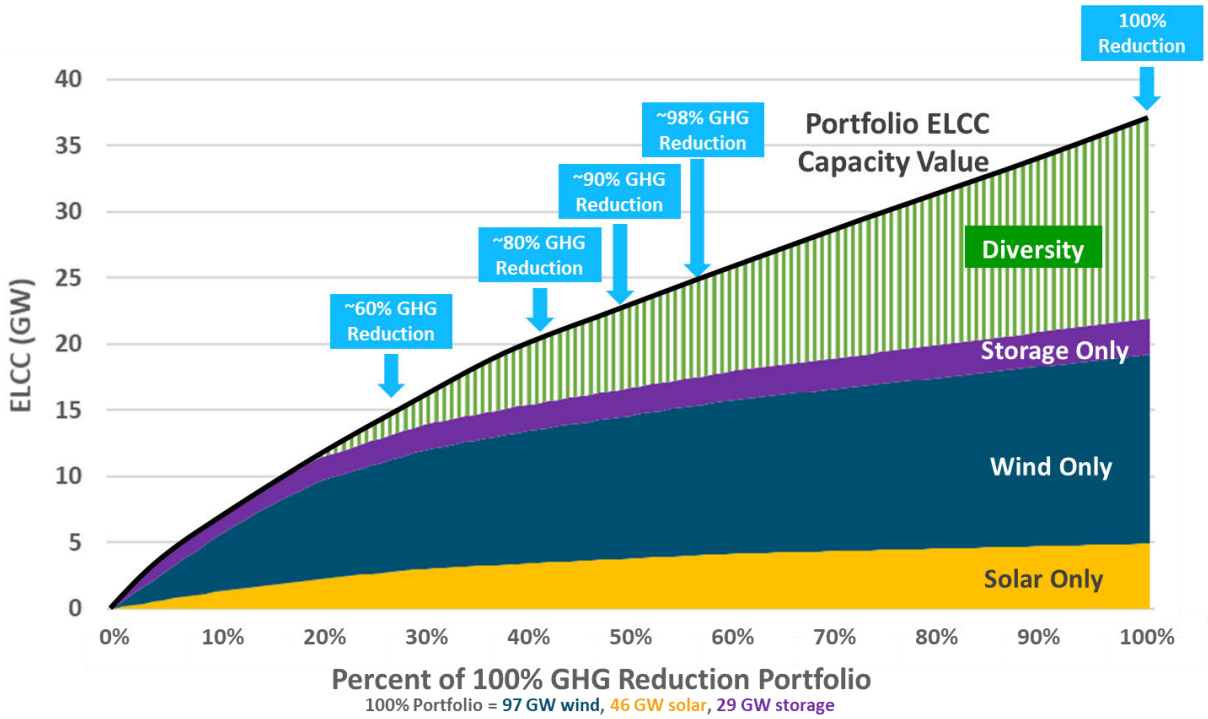
Figure 28: ELCC of Different Portfolios in 2050



5.3.6 SENSITIVITY ANALYSIS

This study also explores the potential resource adequacy needs of a 100% GHG free electricity system recognizing that emerging technologies beyond wind, solar, and electric energy storage that are not yet available today may come to play a significant role in the region's energy future. Specifically, the alternative resources analyzed are: clean baseload, ultra-long duration storage, and biogas which are further described in Table 21.

Table 21: Sensitivity Descriptions

Sensitivity Name	Description
Clean Baseload	Assesses the impact of technology that generates reliable baseload power with zero GHG emissions. This scenario might require a technology such as a small modular nuclear reactor (SMR), fossil generation with 100% carbon capture and sequestration, or other undeveloped or commercially unproven technology.
Ultra-Long Duration Storage	Assesses the impact of an ultra-long duration electric energy storage technology (e.g., 100's of hours) that can be used to integrate wind and solar. This technology is not commercially available today at reasonable cost.
Biogas	Assesses the impact of a GHG free fuel (e.g., biogas, renewable natural gas, etc.) that could be used with existing dispatchable generation capacity.

All three of these alternative technology options have the potential to greatly reduce the required renewable overbuild of the system as shown in Figure 29. This is achieved because each of these technologies is dispatchable and can generate energy during prolonged periods of low wind and solar production when short-duration energy storage would become depleted.

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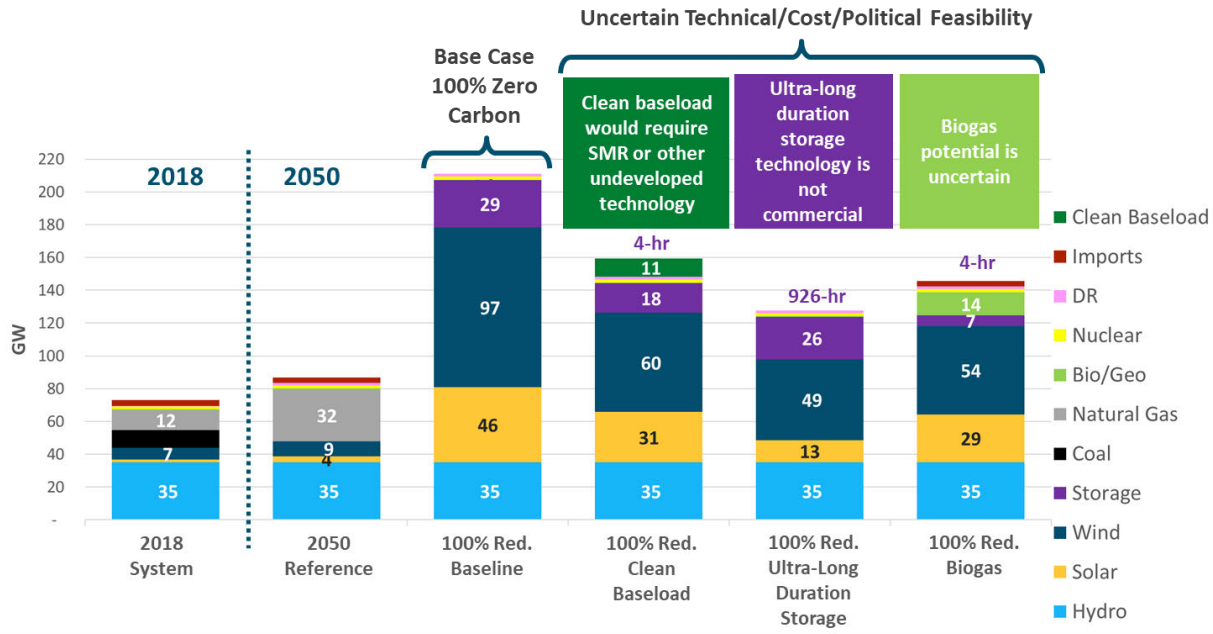
Figure 29: 2050 100% GHG Reduction Sensitivity Portfolio Results



While these alternative technologies clearly highlight the benefits, there are significant technical feasibility, economic, and political feasibility hurdles that stand in the way of large-scale adoption of these alternatives at the present time. In particular, clean baseload would require some technology such as small modular nuclear reactors which is not yet commercially available. Geothermal could provide a clean baseload resources but is limited in technical potential across the region. Fossil generation with carbon capture and sequestration (CCS) is another potential candidate, but the technology is not widely deployed, the cost at scale is uncertain, and current CCS technologies do not achieve a 100% capture rate. Ultra-long duration storage (926 hours) is not commercially available at reasonable cost assuming the technology is limited to battery storage or other commercially proven technologies. Biogas potential is also uncertain and there will be competition from other sectors in the economy to utilize what may be available. A detailed table of installed nameplate capacity for each portfolio is summarized in Appendix A.2.

Table 22 shows key cost metrics for the 100% GHG Reduction sensitivity scenarios. For consistency with the base case scenarios, all costs are relative to the 2050 *Reference* scenario.

Table 22. 100% GHG Reduction Sensitivity Key Cost Metrics

Metric	100% GHG Reduction Baseline	100% GHG Reduction Clean Baseload	100% GHG Reduction Ultra-Long Duration Storage	100% GHG Reduction Biogas
Carbon Emissions (MMT CO_2 / year)	0	0	0	0
Annual Incremental Cost ($B)	$12- $28	$11-$22	$370-$920	$2 - $10
Annual Incremental Cost ($/MWh)	$39-$91	$36-$70	$1,200-$3,000	$5 - $32

Analyzing the portfolio and key cost metrics for each of the 100% GHG Reduction sensitivity cases yields several notable observations.

+ In the Clean Baseload sensitivity, the availability of a carbon-free source of baseload generation dramatically reduces the amount of investment in variable renewables and storage needed to maintain reliability: adding 11 GW of clean baseload resource displaces a portfolio of 15 GW solar, 37 GW wind, and 11 GW of storage. In the context of a highly renewable grid, baseload resources that produce energy round-the-clock—including during periods when variable resources are not available—provide significant reliability value to the system. However, at an assumed price of $91/MWh, the scenario still results in considerable additional costs to ratepayers of between $11-22 billion per year relative to the Reference Scenario.
+ The Ultra-Long Duration Storage sensitivity illustrates a stark direct relationship between the magnitude of renewable overbuild and the storage capability of the system: limiting renewable curtailment while simultaneously serving load with zero carbon generation reliability requires energy storage capability of a duration far beyond today's commercial applications (this relationship is further explored in Figure 30 below). Without significant breakthrough in storage technologies, such a portfolio is beyond both technical and economic limits of feasibility.

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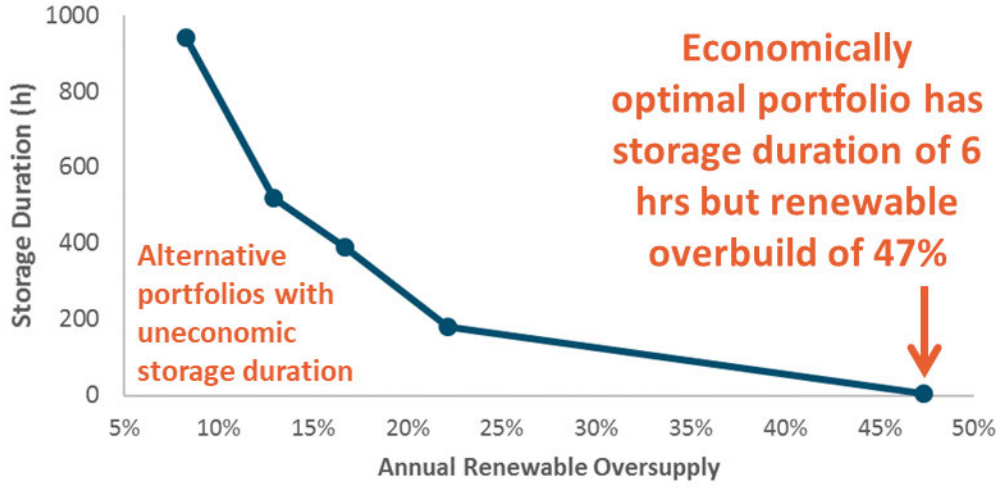
Figure 30: Tradeoff between Renewable Curtailment and Storage Duration



+ The Biogas sensitivity demonstrates the relatively high value of the potential option to combust renewable natural gas in existing gas infrastructure. In this scenario, 14 GW of existing and new gas generation capacity is retained by 2050, serving as a reliability backstop for the system during periods of prolonged low renewable output by burning renewable gas. This sensitivity offers the lowest apparent cost pathway to a zero-carbon electric system because biogas generation does not require significant additional capital investments. While the biogas fuel is assumed to be quite expensive on a unit cost basis, the system doesn't require very much fuel, so the total cost remains reasonable. Moreover, biogas generation uses the same natural gas delivery and generation infrastructure as the Reference Case, significantly reducing the capital investments required. However, the availability of sufficient biomass feedstock to meet the full needs of the electric sector remains an uncertainty. Moreover, there may be competing uses for biogas in the building and industrial sectors that inhibit the viability of this approach.

6 Discussion & Implications

6.1 Land Use Implications of High Renewable Scenarios

Renewables such as wind and solar generation require much greater land area to generate equivalent energy compared to generation sources such as natural gas and nuclear. In the deep decarbonization scenarios, significant amount of land area is required for renewable development. In the 100% GHG Reduction Scenario, estimates of total land use vary from 3 million acres to 14 million acres which is equivalent to 20 to 100 times the land area of Portland and Seattle combined. This is almost three times the land use required under the 80% GHG Reduction scenario.

Table 23. Renewable Land Use in 2050

2050 Scenario	Units	Solar Total Land Use	Wind – Direct Land[19] Use	Wind – Total Land[20] Use
80% GHG Reduction	Thousand acres	84	94	1,135 – 5,337
100% GHG Reduction	Thousand acres	361	241	2,913 – 13,701

Even though such vast expanses of land are available, achieving very high levels of decarbonization would require extensive land usage for such large renewable development. Additionally, significant quantities of land would be required to site the necessary transmission to deliver the renewable energy.

[19] Direct land use is defined as disturbed land due to physical infrastructure development and includes wind turbine pads, access roads, substations and other infrastructure

[20] Total land use is defined as the project footprint as a whole and is the more commonly cited land-use metric associated with wind plants. They vary with project and hence as presented as a range

Both direct and total land use for wind is sourced from NREL's technical report: https://www.nrel.gov/docs/fy09osti/45834.pdf

Land use for solar is sourced from NREL's technical report: https://www.nrel.gov/docs/fy13osti/56290.pdf

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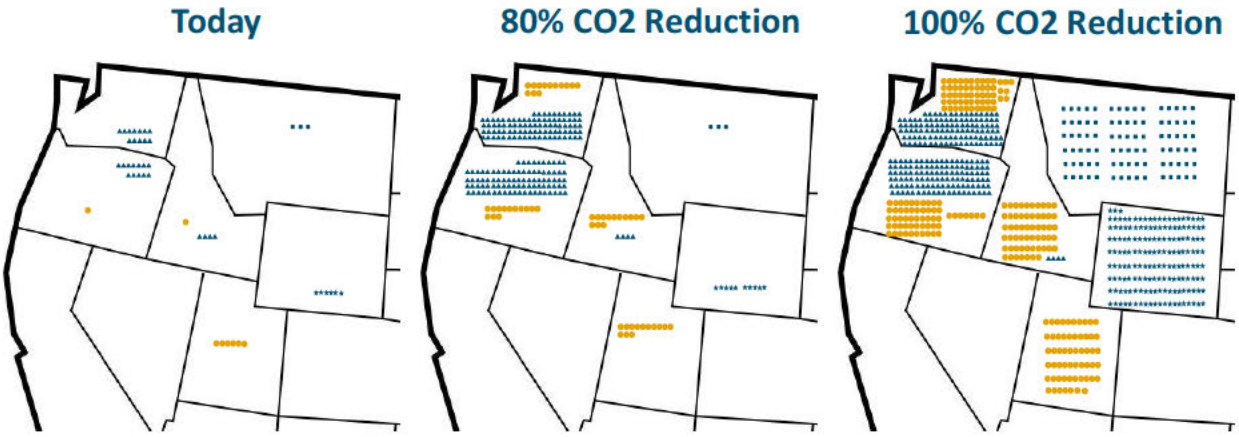
Figure 31 highlights the scale of renewable development that would be required to achieve 100% GHG reductions via only wind, solar, and storage. Each dot in the map represents a 200 MW wind or solar farm. Note that sites are not to scale or indicative of site location.

Figure 31: Map of Renewable Land Use Today and in 80% and 100% GHG Reduction Scenario. Each dot represents one 200 MW power plant (blue = wind, yellow = solar)



6.2 Reliability Standards

Determining the reliability standard to which each electricity system plans its resource adequacy is the task of each individual Balancing Authority as there is no mandatory or voluntary national standard. There are several generally accepted standards used in resource adequacy across North America, with the most common being the "1-in-10" standard. There is, however, a range of significant interpretations for this metric. Some interpret it as one loss-of-load ***day*** every ten years. Some interpret it as one loss-of-load ***event*** every ten years. And some interpret it as one loss-of-load ***hour*** every ten years. The translation of these interpretations into measurable reliability metrics further compounds inconsistency across jurisdictions. However, the ultimate interpretation of most jurisdictions ultimately boils down to the use of one of four reliability metrics:

+ **Annual Loss of Load Probability (aLOLP)**
    - The probability in a year that load + reserves exceed generation at any time
+ **Loss of Load Frequency (LOLF)**
    - The total number of events in a year where load + reserves exceed generation
+ **Loss of Load Expectation (LOLE)**
    - The total number of hours in a year where load + reserves exceed generation
+ **Expected Unserved Energy (EUE)**
    - The total quantity of unserved energy in a year when load + reserves exceed generation

Each of these metrics provides unique insight into the reliability of the electric system and provides information that cannot be ascertained by simply using the other metrics. At the same time, each of the metrics is blind to many of the factors that are ascertained through the other metrics.

The NWPCC sets reliability standards for the Pacific Northwest to have an annual loss of load probability (aLOLP) to be below 5%. This would mean loss-of-load events occur, on average, less than once in 20 years. However, this metric does not provide any information on the number of events, duration of events, or magnitude of events that occur during years that experience loss of load. While this metric has generally served the region well when considering that the biggest reliability drive (hydro) was on an annual cycle, this metric becomes increasingly precarious when measuring a system that is more and more dependent upon renewables.

This study uses loss of load expectation (LOLE), because it is a more common metric that is used by utilities and jurisdictions across the country. Unlike aLOLP, LOLE does yield insight on the duration of events which can help to provide greater detail whether or not a system is adequately reliable.

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However, LOLE does not capture the magnitude of events when they occur and thus misses a potentially large measure of reliability as compared to a metric such as EUE. EUE captures the total quantity of energy that is expected to go unserved each year. While this metric is not perfect, it is likely the most robust metric in terms of measuring the true reliability of an electric system, particularly in a system that is energy-constrained. Despite these attributes, EUE is not commonly used as a reliability metric in the industry today.

RECAP calculates all the aforementioned reliability metrics and can be used to compare and contrast their performance across different portfolios. Table 24 shows the four reliability metrics across different 2050 decarbonization scenarios.

Table 24: Reliability Statistics Across 2050 Decarbonization Portfolios

Reliability Metric	Units	2050 Reference	80% GHG Red.	100% GHG Red.
aLOLP	%/yr	**3.6%**	**8.1%**	**10.5%**
LOLF	#/yr	**0.16**	**0.29**	**0.13**
LOLE	hrs/yr	**2.4**	**2.4**	**2.4**
EUE	GWh/yr	**1.0**	**2.0**	**19.0**

Because the portfolios were calibrated to meet a 2.4 hrs./yr. LOLE standard, all portfolios yield exactly this result. However, this does not mean that all portfolios are equally reliable. Notably, the 100% GHG Reduction scenario has nearly 20 times the quantity of expected unserved energy (EUE) as compared to the reference scenario. The value of unserved energy varies widely depending on the customer type and outage duration; studies typically put the value between $5,000 and $50,000/MWh. This means that the economic cost of unserved energy in the 2050 Reference Scenario is between $5 million and $50 million per year. However, in the 100% GHG Reduction Scenario, which meets the same target for LOLE, the value of unserved energy could be nearly $1 billion annually.

This gives an important insight to some of the qualities of a system that is highly dependent upon dispatch-limited resources. For a traditional system that is composed mainly of dispatchable generation (coal, natural gas, nuclear, etc.), the primary reliability challenge is whether there is enough capacity to serve peak load. Even if the peak is slightly higher than expected or power plants experience forced outages and are unavailable to serve load, the difference between available generation and total load should be relatively small. Conversely, for a system that is highly dependent upon variable generation and other dispatch limited generation, there is a much greater chance that the sum of total generation could be *significantly* lower than total load. This phenomenon was highlighted in Section 5.3.3. The reliability statistics above confirm this intuition by highlighting how aLOLP, LOLF, and LOLE are each uniquely inadequate to fully capture the reliability of a system that is highly dependent upon variable renewable energy. For a system that is heavily dependent on variable generation, EUE may be a more useful reliability metric than the conventional LOLE metrics.

6.3 Benefits of Reserve Sharing

One of the simplifying assumptions made in this study to examine reliability across the Greater Northwest is the existence of a fully coordinated planning and operating regime within the region. In reality, however, responsibility for maintaining reliability within the system is distributed among individual utilities and balancing authorities with oversight from state utility commissions. The current distributed approach to reliability planning has two interrelated shortcomings:

1) Because the region's utilities each plan to meet their own needs, they may not rigorously account for the natural load and resource diversity that exists across the footprint. If each utility built physical resources to meet its own need, the quantity of resources in the region would greatly exceed what would be needed to meet industry standards for loss-of-load.

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2) As an informal mechanism for taking advantage of the load and resource diversity that exists in the region, many utilities rely on front-office transactions (FOTs) or market purchases instead of physical resources, as was discussed in Section 2. This helps to reduce costs to ratepayers of maintaining reliability by avoiding the construction of capacity resources. However, as the region transitions from a period of capacity surplus to one of capacity deficit, and because there is no uniform standard for capacity accreditation, there is a risk that overreliance on FOTs could lead to underinvestment in resources needed to meet reliability standards.

Formal regional planning reserve sharing could offer multiple benefits in the Greater Northwest by taking advantage of load and resource diversity that exists across the region. A system in which each utility builds physical assets to meet its own needs could result in overcapacity, because not every system peaks at the same time. Planning to meet regional coincident peak loads requires less capacity than meeting each individual utility's peak loads. Further, surplus resources in one area could be utilized to meet a deficit in a neighboring area. Larger systems require lower reserve margins because they are less vulnerable to individual, large contingencies. A regional entity could adopt more sophisticated practices and computer models than individual utilities and manage capacity obligation requirements independent from the utilities.

Table 25 provides a high-level estimate of the benefits that could accrue if the Northwest employed a formal planning reserve sharing system. The benefits are divided into (1) benefits due to switching from individual utility peak to regional peak and (2) benefits due to lower target PRM.

A regional planning reserve sharing system could be established in the Greater Northwest. A regional entity could be created as a voluntary organization of utilities and states/provinces. The regional entity would perform loss-of-load studies for the region and calculate the regional PRM and develop accurate methods for estimating capacity credit of hydro and renewables. The entity would create a forward

capacity procurement obligation based on studies and allocate responsibility based on their share of the regional requirement.

Table 25. Possible Benefits from a Regional Planning Reserve Sharing System in the Northwest[21]

Capacity Requirement	BPA + Area	NWPP (US)
Individual Utility Peak + 15% PRM (MW)	33,574	46,398
Regional Peak + 15% PRM (MW)	32,833	42,896
Reduction (MW)	741	3,502
Savings ($MM/year)	***$89***	***$420***
	BPA + Area	**NWPP (US)**
Regional Peak + 12% PRM (MW)	31,977	41,777
Reduction (MW)	1,597	4,621
Savings ($MM/year)	***$192***	***$555***

Rules similar to other markets could be made for standardized capacity accreditation of individual resources such as dispatchable generation, hydro generation, variable generation, demand response and energy storage. Tradable capacity products could be defined based on the accredited capacity.

A regional entity could be formed by voluntary association in the Greater Northwest. It could be governed by independent or stakeholder board. Alternatively, new functionality could be added to the existing reserve sharing groups such as Northwest Power Pool (NWPP) and Southwest Reserve Sharing Group, which expand their operating reserve sharing to include planning reserve sharing. It would not require setting up a regional system operator immediately and PRM sharing could be folded into a regional system operator if and when it forms.

[21] Calculated regional and non-coincident peaks using WECC hourly load data averaged over 2006-2012. Savings value estimated using capacity cost of $120/kW-yr. Assumes no transmission constraints within the region. Ignores savings already being achieved through bilateral contracts

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7 Conclusions

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

This study finds that deep decarbonization of the Northwest grid is feasible without sacrificing reliable electric load service. But this study also finds that, absent technological breakthroughs, achieving 100% GHG reductions using *only* wind, solar, hydro, and energy storage is both impractical and prohibitively expensive. Firm capacity – capacity that can be relied upon to produce energy when it is needed the most, even during the most adverse weather conditions – is an important component of a deeply-decarbonized grid. Increased regional coordination is also a key to ensuring reliable electric service at reasonable cost under deep decarbonization.

7.1 Key Findings

1. It is possible to maintain Resource Adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient **firm capacity** is available during periods of low wind, solar, and hydro production;

    - Natural gas generation is the most economic source of firm capacity today;
    - Adding new gas generation capacity is not inconsistent with deep reductions in carbon emissions because the significant quantities of zero-marginal-cost renewables will ensure that gas is only used during reliability events;
    - Wind, solar, demand response, and short-duration energy storage can contribute but have important limitations in their ability to meet Northwest Resource Adequacy needs;
    - Other potential low-carbon firm capacity solutions include (1) new nuclear generation, (2) fossil generation with carbon capture and sequestration, (3) ultra-long duration electricity storage, and (4) replacing conventional natural gas with carbon-neutral gas such as hydrogen or biogas.

2. It would be **extremely costly and impractical** to replace all carbon-emitting firm generation capacity with solar, wind, and storage, due to the very large quantities of these resources that would be required;

    - Firm capacity is needed to meet the new paradigm of reliability planning under deep decarbonization, in which the electricity system must be designed to withstand prolonged periods of low renewable production once storage has depleted; renewable overbuild is the most economic solution to completely replace carbon-emitting resources but requires a 2x buildout that results in curtailment of almost half of all wind and solar production.

3. The Northwest is expected to need new capacity in the near term in order to maintain an acceptable level of Resource Adequacy after planned coal retirements.

4. Current planning practices risk underinvestment in the new capacity needed to ensure Resource Adequacy at acceptable levels;

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- Reliance on market purchases or front-office transactions (FOTs) reduces the cost of meeting Resource Adequacy needs on a regional basis by taking advantage of load and resource diversity among utilities in the region;
- Capacity resources are not firm without a firm fuel supply; investment in fuel delivery infrastructure may be required to ensure Resource Adequacy even under a deep decarbonization trajectory;
- Because the region lacks a formal mechanism for ensuring adequate physical firm capacity, there is a risk that reliance on market transactions may result in double-counting of available surplus generation capacity;
- The region might benefit from and should investigate a formal mechanism to share planning reserves on a regional basis, which may help ensure sufficient physical firm capacity and reduce the quantity of capacity required to maintain Resource Adequacy

Appendix A. Assumption Development Documentation

A.1 Baseline Resources

Table 26. NW Baseline Resources Installed Nameplate Capacity (MW) by Year.

Category	Resource Class	2018	2030	2050
Thermal	Natural Gas	12,181	19,850	31,500
	Coal	10,895	8,158	0
	Nuclear	1,150	1,150	1,150
	Total	**24,813**	**29,745**	**33,237**
Firm Renewable	Geothermal	79.6	79.6	79.6
	Biomass	489.2	489.2	489.2
Variable Renewables	Wind	7,079	7,079	9,205
	Solar	1,557	1,557	3,593
Hydro	Hydro	35,221	35,221	35,221
Storage	Storage	0	0	0
DR	Shed Demand Response	600	2,200	5,500
Imports	Imports*	3,400	3,400	3,400

*Imports consist of market purchases and non-summer firm imports. For more details, please refer to Imports section.

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A.2 Portfolios of Different Scenarios

Table 27. Portfolios for 2030 scenarios – Installed Nameplate Capacity (GW) by Scenario

Resource Class	Reference	No Coal
Solar	1.6	1.6
Wind	7.1	7.1
DR	2.2	2.2
Hydro	35.2	35.2
Coal	8.2	-
Natural Gas	19.9	28.0
Nuclear	1.2	1.2
Bio/Geo	0.6	0.6
Storage	-	-
Imports	3.4	3.4

Table 28. Portfolios for 2050 scenarios – Installed Nameplate Capacity (GW) by Scenario

Resource Class	Reference	60% GHG Reduction	80% GHG Reduction	90% GHG Reduction	98% GHG Reduction	100% GHG Reduction
Solar	3.6	10.6	10.6	10.6	29.2	45.6
Wind	9.2	22.9	38.0	48.2	53.8	97.4
DR	5.5	5.5	5.5	5.5	5.5	5.5
Hydro	35.2	35.2	35.2	35.2	35.2	35.2
Coal	-	-	-	-	-	-
Natural Gas	31.5	25.5	23.5	19.5	13.5	-
Nuclear	1.2	1.2	1.2	1.2	1.2	1.2
Bio/Geo	0.6	0.6	0.6	0.6	0.6	0.6
Storage	-	2.2 (4-hr)	2.2 (4-hr)	4.4 (4-hr)	6.7 (4-hr)	28.7 (6-hr)
Imports	3.4	3.4	3.4	3.4	3.4	-

Table 29. Zero Carbon Sensitivity Portfolios in 2050– Installed Nameplate Capacity (GW) by Scenario

Resource Class	100% GHG Reduction Renewables	100% GHG Reduction Baseload Tech	100% GHG Reduction Long Duration Storage	100% GHG Reduction Biogas
Solar	45.6	30.7	13.5	29.2
Wind	97.4	60.5	49.2	53.8
DR	5.5	5.5	5.5	5.5
Hydro	35.2	35.2	35.2	35.2
Coal	-	-	-	-
Natural Gas	-	-	-	13.5
Nuclear	1.2	1.2	1.2	1.2
Bio/Geo	0.6	0.6	0.6	0.6
Storage	28.7 (6-hr)	18.0 (4-hr)	25.9 (926-hr)	6.7 (4-hr)
Clean Baseload	-	11.3	-	-
Imports	-	-	-	-

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Appendix B. RECAP Model Documentation

B.1 Background

RECAP is a loss-of-load-probability model developed by E3 to examine the reliability of electricity systems under high penetrations of renewable energy and storage. In this study, RECAP is used to assess reliability using the *loss-of-load expectation* (LOLE) metric. LOLE measures the expected number of hours/yr when load exceeds generation, leading to a loss-of-load event.

LOLE is one of the most commonly used metrics within the industry across North America to measure the resource adequacy of the electricity system. LOLE represents the reliability over many years and does not necessarily imply that a system will experience loss-of-load every single year. For example, if an electricity system is expected to have two 5-hour loss-of-load events over a ten-year period, the system LOLE would be 1.0 hr./yr LOLE (10 hours of lost load over 10 years).

There is no formalized standard for LOLE sufficiency promulgated by the North American Electric Reliability Coordinating Council (NERC), and the issue is state-jurisdictional in most places expect in organized capacity markets. In order to ensure reliability in the electricity system, the Northwest Power and Conservation Council (NWPCC) set reliability standards for the Pacific Northwest. The current reliability standard requires the electricity system to have an annual loss of load probability (annual LOLP) to be below 5%. This would mean loss-of-load events occur, on average, less than once in 20 years. However, in a system with high renewables, LOLE is a more robust reliability metric.

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B.2 Model Overview

RECAP calculates LOLE by simulating the electric system with a specific set of generating resources and economic conditions under a wide variety of weather years, renewable generation years, hydro years, and stochastics forced outages of generation and transmission resources, while accounting for the correlation and relationships between these. By simulating the system thousands of times under different combinations of these conditions, RECAP is able to provide a statistically significant estimation of LOLE.

B.2.1 LOAD

E3 modeled hourly load for the northwest under current economic conditions using the weather years 1948-2017 using a neural network model. This process develops a relationship between recent daily load and the following independent variables:

- Max and min daily temperature (including one and two-day lag)
- Month (+/- 15 calendar days)
- Day-type (weekday/weekend/holiday)
- Day index for economic growth or other linear factor over the recent set of load data

The neural network model establishes a relationship between daily load and the independent variables by determining a set of coefficients to different nodes in hidden layers which represent intermediate steps in between the independent variables (temp, calendar, day index) and the dependent variable (load). The model trains itself through a set of iterations until the coefficients converge. Using the relationship established by the neural network, the model calculates daily load for all days in the weather record (1948-2017) under current economic conditions. The final step converts these daily load totals into hourly loads. To do this, the model searches over the actual recent load data (10 years) to find the day that is closest in total daily load to the day that needs an hourly profile. The model is constrained to search within identical

day-type (weekday/weekend/holiday) and +/- 15 calendar days when making the selection. The model then applies this hourly load profile to the daily load MWh.

This hourly load profile for the weather years 1948-2017 under today's economic conditions is then scaled to match the load forecast for future years in which RECAP is calculating reliability. This 'base' load profile only captures the loads that are present on the electricity system today and do not very well capture systematic changes to the load profile due to increased adoption of electric vehicles, building space and water heating, industrial electrification. Load modification through demand response is captured through explicit analysis of this resource in Section 0.

Operating reserves of 1,250 MW are also added onto load in all hours with the assumption being that the system operator will shed load in order to maintain operating reserves of at least 1,250 MW in order to prevent the potentially more catastrophic consequences that might result due to an unexpected grid event coupled with insufficient operating reserves.

B.2.2 DISPATCHABLE GENERATION

Available dispatchable generation is calculated stochastically in RECAP using forced outage rates (FOR) and mean time to repair (MTTR) for each individual generator. These outages are either partial or full plant outages based on a distribution of possible outage states developed using NWPCC data. Over many simulated days, the model will generate outages such that the average generating availability of the plant will yield a value of (1-FOR).

B.2.3 TRANSMISSION

RECAP is a zonal model that models the northwest system as one zone without any internal transmission constraints. Imports are assumed to be available as mentioned in Imports Section 4.2.3.

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B.2.4 WIND AND SOLAR PROFILES

Hourly wind and solar profiles were simulated at all wind and solar sites across the northwest. Wind speed and solar insolation data was obtained from the NREL Western Wind Toolkit[22] and the NREL Solar Prospector Database[23], respectively and transformed into hourly production profiles using the NREL System Advisor Model (SAM). Hourly wind speed data was available from 2007-2012 and hourly solar insolation data was available from 1998-2014.

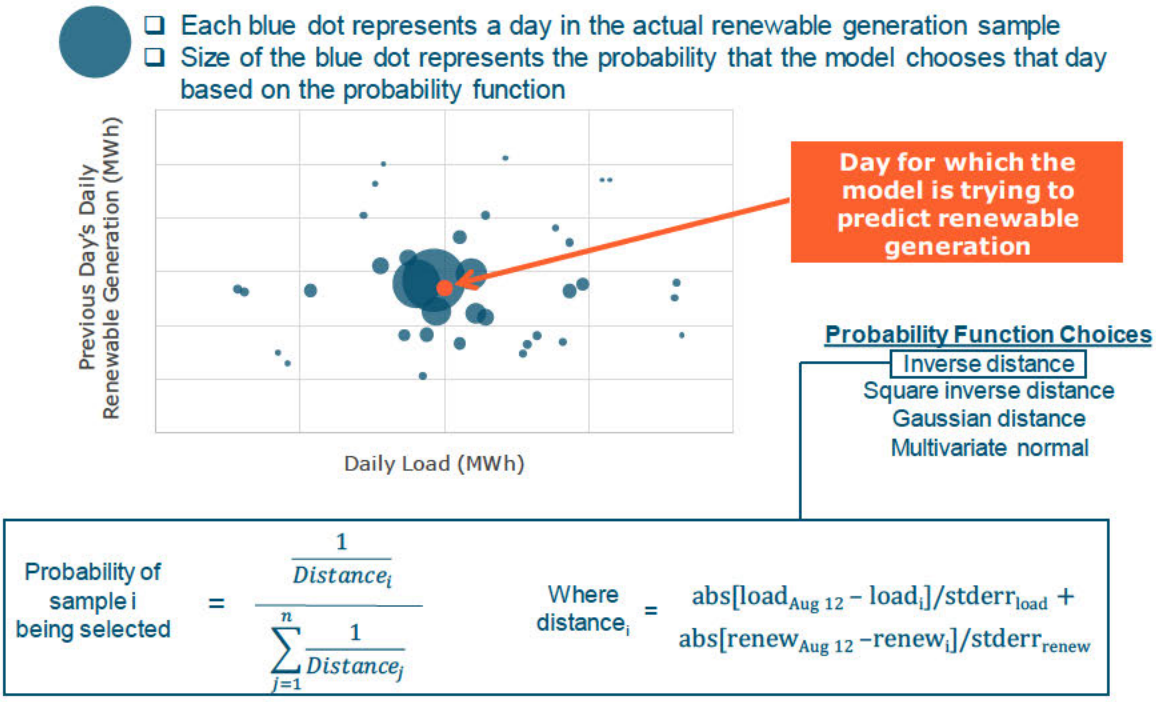
A stochastic process was used to match the available renewable profiles with historical weather years using the observed relationship for years with overlapping data i.e., years with available renewable data. For each day in the historical load profile (1948-2017), the model stochastically selects a wind profile and a solar profile using an inverse distance function with the following factors:

- Season (+/- 15 days)
  - Probability is 1 inside this range and 0 outside of this range
- Load
  - For winter peaking systems like the northwest, high load days tend to have low solar output
- Previous Day's Renewable Generation
  - High wind or solar days have a higher probability of being followed by a high wind or solar day, and vice versa. This factor captures the effect of a multi-day low solar or low wind event that can stress energy-limited systems that are highly dependent on renewable energy and/or energy storage.

A graphic illustrating this process is shown in Figure 32

[22] https://www.nrel.gov/grid/wind-toolkit.html
[23] https://nsrdb.nrel.gov/

Figure 32: Renewable Profile Selection Process



B.2.5 HYDRO DISPATCH

Dispatchable hydro generation is a hybrid resource that is limited by weather (rainfall) but can still be dispatched for reliability within certain constraints. It is important to differentiate this resource from non-dispatchable hydro such as many run-of-river systems that produce energy when there is hydro available, similar to variable wind and solar facilities, especially in a system like northwest which has an abundance of hydro generation.

To determine hydro availability, the model uses a monthly historical record of hydro production data from NWPCC's records from 1929 – 2008. The same data is used to model hydro generation in NWPCC's GENESYS model. For every simulated load year, a hydro year is chosen stochastically from the historical database. The study assumes no significant hydro build in the future and no correlation with temperature,

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load or renewable generation. Once the hydro year is selected, the monthly hydro budgets denote the amount of energy generated from hydro resources in that month. Since RECAP optimizes the hydro dispatch to minimize loss-of-load, providing only monthly budgets can dispatch hydro extremely flexibly. For example, some of the hydro can be held back to be dispatched during generator outages. Such high flexibility in hydro dispatch is not representative of the current northwest hydro system. Therefore, the monthly budget is further divided into weekly budgets to ensure hydro dispatch is in line with operating practices in the northwest.

In addition to hydro budgets, hydro dispatch has other upstream and downstream hydrological and physical constraints that are modeled in a hydrological model by NWPCC. RECAP does not model the complete hydrological flow but incorporates all the major constraints such as sustained peaking (maximum generation and minimum generation) limits. Sustained peaking maximum generation constraint results in the average hydro dispatch over a fixed duration to be under the limit. Similarly, minimum generation constraints ensure average dispatch over a fixed duration is above the minimum generation sustainable limits. Sustainable limits are provided over 1-hour, 2-hour, 4-hour and 10-hour durations.

The weekly budgets and sustained peaking limits together make the hydro generation within RECAP representative of the actual practices associated with hydro generation in the northwest. Output from RECAP are benchmarked against hydro outputs from NWPCC's GENESYS model.

B.2.6 STORAGE

The model dispatches storage if there is insufficient generating capacity to meet load net of renewables and hydro. Storage is reserved specifically for reliability events where load exceeds available generation. It is important to note that storage is not dispatched for economics in RECAP which in many cases is how storage would be dispatched in the real world. However, it is reasonable to assume that the types of reliability events that storage is being dispatched for (low wind and solar events), are reasonably

foreseeable such that the system operator would ensure that storage is charged to the extent possible in advance of these events. (Further, presumably prices would be high during these types of reliability events so that the dispatch of storage for economics also would satisfy reliability objectives.)

B.2.7 DEMAND RESPONSE

The model dispatches demand response if there is still insufficient generating capacity to meet load even after storage. Demand response is the resource of last resort since demand response programs often have a limitation on the number of times they can be called upon over a set period of time. For this study, demand response was modeled using a maximum of 10 calls per year, with each call lasting for a maximum of 4 hours.

B.2.8 LOSS-OF-LOAD

The final step in the model calculates loss-of-load if there is insufficient available dispatchable generation, renewables, hydro, storage, and demand response to serve load + operating reserves.

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Appendix C. Renewable Profile Development

The electricity grid in the Greater Northwest consists of significant quantities of existing wind and solar generation. Significant new renewable build is expected to be built in the future, as explored in this study. Representing the electricity generation from both existing and future renewable (solar and wind) resources is fundamental to the analysis in this study. In this appendix section, the process of developing these renewable profiles for both existing and new renewable resources is elaborated.

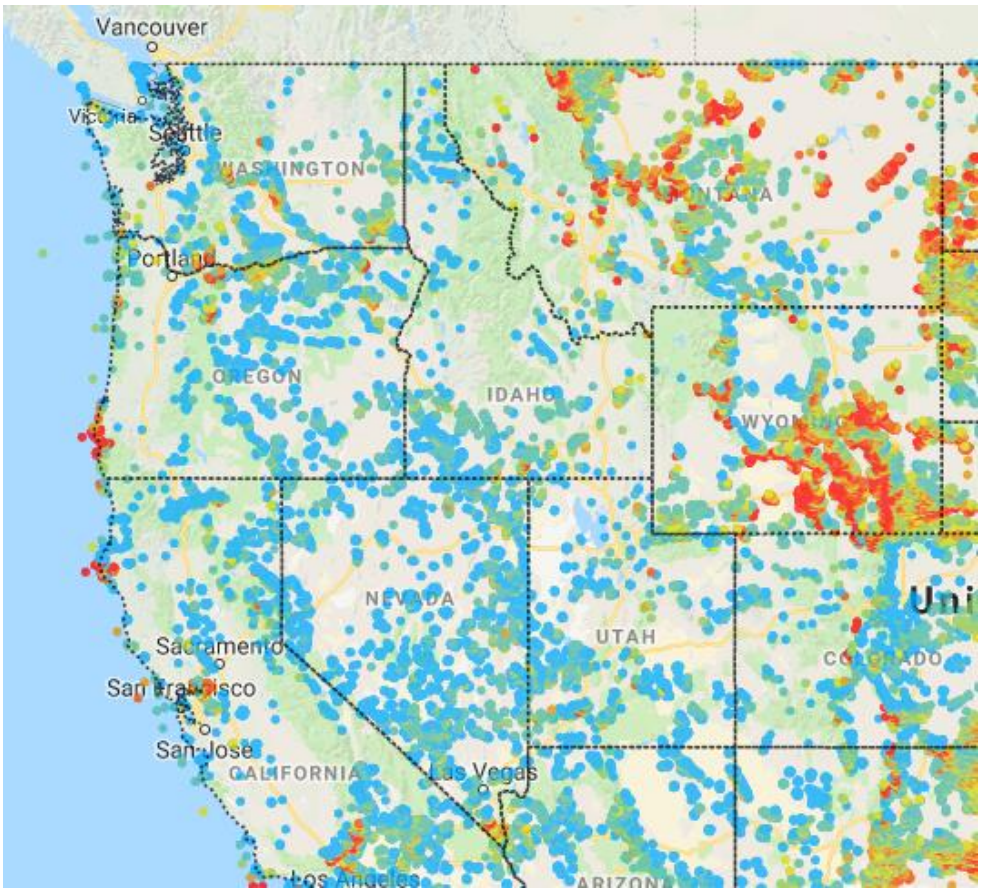
C.1 Wind Profiles

C.1.1 SITE SELECTION

Existing wind site locations (latitude and longitude) in the study region are obtained from NWPCC's generator database and WECC's Anchor Data Set. New candidate wind sites are identified based on the highest average wind speed locations across the Greater Northwest region using data published by NREL[24] (see Figure 33).

[24] https://maps.nrel.gov/wind-prospector/

Figure 33: Wind speed data in the northwest (Source: NREL)



While striving to place new candidate wind sites in the windiest locations, the new candidate sites are spread across each state in a way that they span a large geographical area in order to capture diversity in wind generation (e.g. the likelihood that the wind will be blowing in one location even when it is not in another). The new candidate sites used in this study are shown in Figure 34. New sites were aggregated geographically into three single resources that were used in the study modeling: Northwest, Montana, and Wyoming. For example, Montana wind in the study is represented as a single profile with new wind turbines installed proportionally across the various "blue squares" shown in Figure 34.

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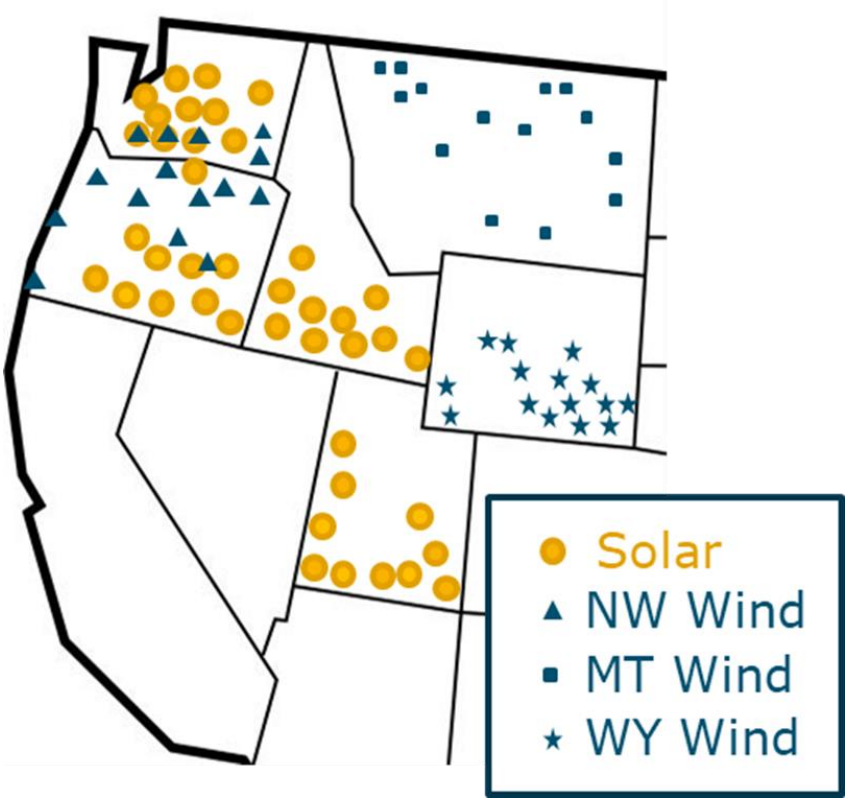
Figure 34: New Candidate Solar and Wind Sites



C.1.2 PROFILE SIMULATION

NREL's Wind Integration National Dataset (WIND) Toolkit[25] contains historical hourly wind speed data from 2007-2012 for every 2-km x 2-km grid cell in the continental United States. This data is downloaded for each selected site location (both existing and new sites).

[25] https://www.nrel.gov/grid/wind-toolkit.html

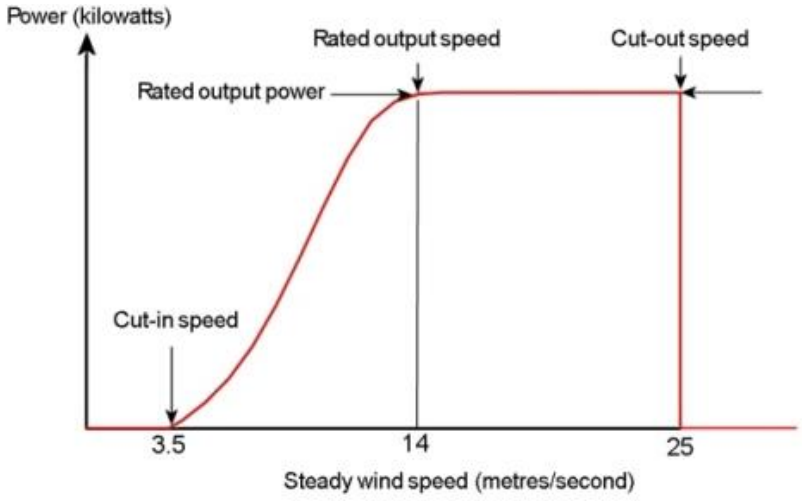
The amount of electricity generated from a wind turbine is a function of wind speed and turbine characteristics, such as the turbine hub height (height above the ground), and the turbine power curve (the mapping of the windspeed to the corresponding power output). Wind speeds increase with height above the ground. Since all NREL WIND data is reported at 100-meters, the wind profile power law is used to scale wind speeds to different heights, depending on the height of the turbine being modeled. This relationship is modeled as:

$$\frac{wind\ speed\ at\ height\ x}{wind\ speed\ at\ heigh\ y} = (\frac{height\ x}{height\ y})^{wind\ shear\ coefficient}$$

A wind shear coefficient of 0.143 is used in this study.

A typical power curve is shown in Figure 35. Turbine power curves define the cut-in speed (minimum windspeed for power generation), rated speed (minimum wind speed to achieve maximum turbine output), cut-out speed (maximum wind speed for power generation) and power generation between the cut-in speed and rated speed.

Figure 35: Typical Wind Turbine Power Curve



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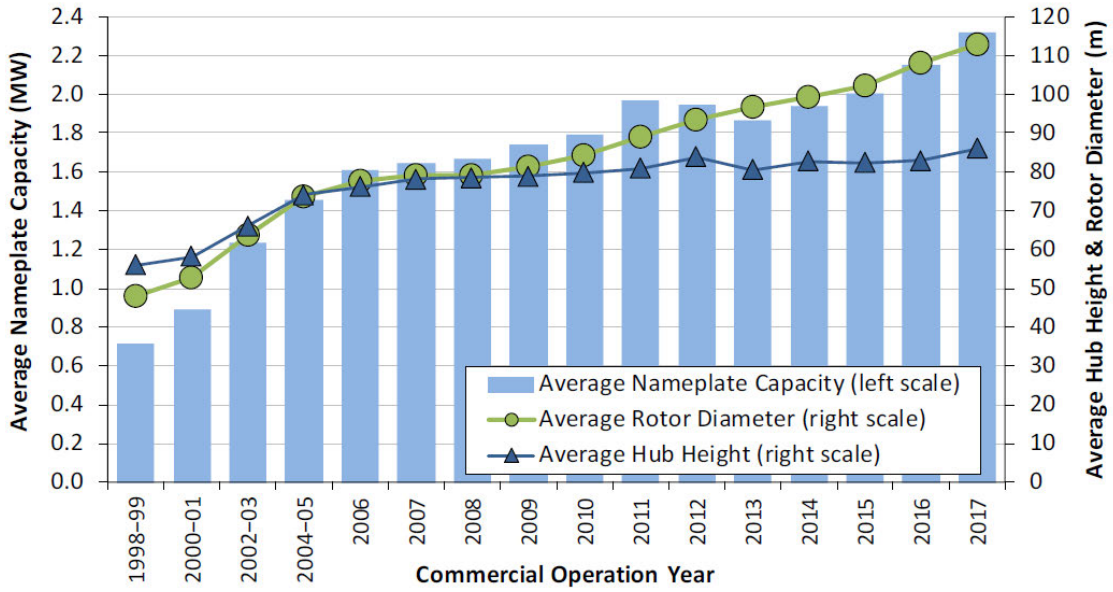
With the advancement of wind turbine technology, hub heights have increased over the years (see Figure 36). For existing wind resources, the hub heights are assumed to be the annual average hub height based on the install year. For new turbines, hub height is assumed to be 100 meters.

Figure 36: Average turbine nameplate capacity, rotor diameter and hub height for land-based wind project in the US



For existing turbines, *Nordic 1000 54m 1 MW (MT)* turbine power curve generates wind profiles that benchmark well to the historical generation profiles. The validation process of turbine power curve selection is described in greater detail in Section C.1.3. For new turbines, NREL standard power turbine curves are used to produce future wind profiles.

The wind generation profiles simulation process can be performed for each 2 km X 2 km grid cell and are usually limited to maximum power of 8 - 16 MW due to land constraints and the number of turbines that can fit within that area. However, each wind site that is selected as described in Section C.1.1 (shown in Figure 34), was modeled as 3 GW of nameplate installed wind capacity and encompasses hundreds of

adjacent grid cells from the NREL WIND Toolkit database. Note that the actual installed wind capacity varies by scenario in the study and so these 3 GW profiles were scaled up and down to match the installed capacity of each specific scenario. The adjacent grid cells are chosen such that they are the closest in geographical distance from the first wind site location (first grid cell). Representing a single wind site using hundreds of grid cells represents wind production more accurately and irons out any local production spikes that are limited to only a few grid cells in the NREL WIND Toolkit database.

C.1.3 VALIDATION

BPA publishes historical wind production data[26] in its service territory. This data is used to identify a turbine power curve that best benchmarks wind energy production from existing projects as simulated using historical wind speed data. Three turbine power curves were tested – *GE 1.5SLE 77m 1.5mW (MG)*, *Nordic 1000 54m 1Mw (MT)*, and *NREL standard.* Based on annual capacity factors and hourly generation matching, *Nordic 1000 54m 1Mw (MT)* turbine was selected to represent existing wind turbines in the study. These benchmarking results are illustrated in Figure 37 and Figure 38.

[26] https://transmission.bpa.gov/business/operations/wind/

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Figure 37: Comparison of Annual Wind Capacity Factors for Benchmarking

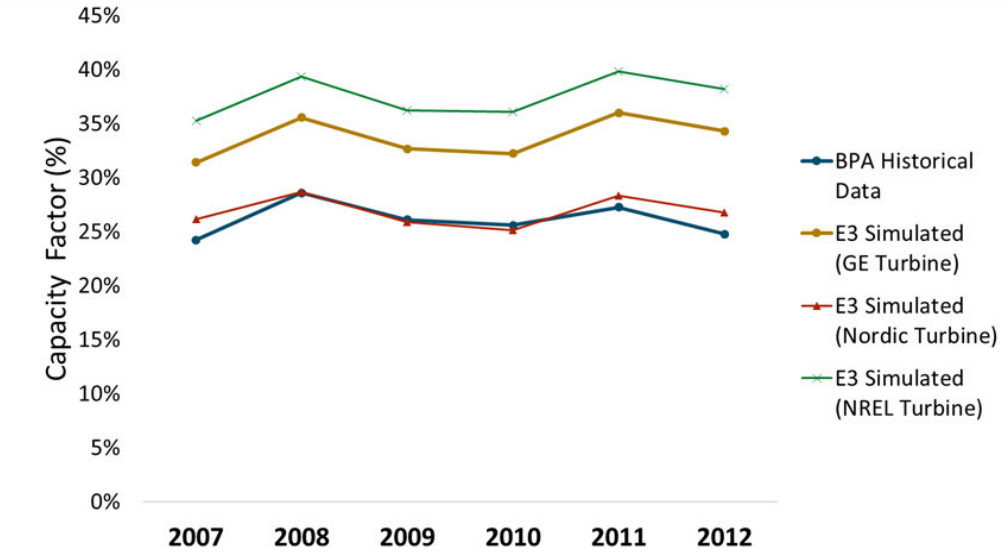
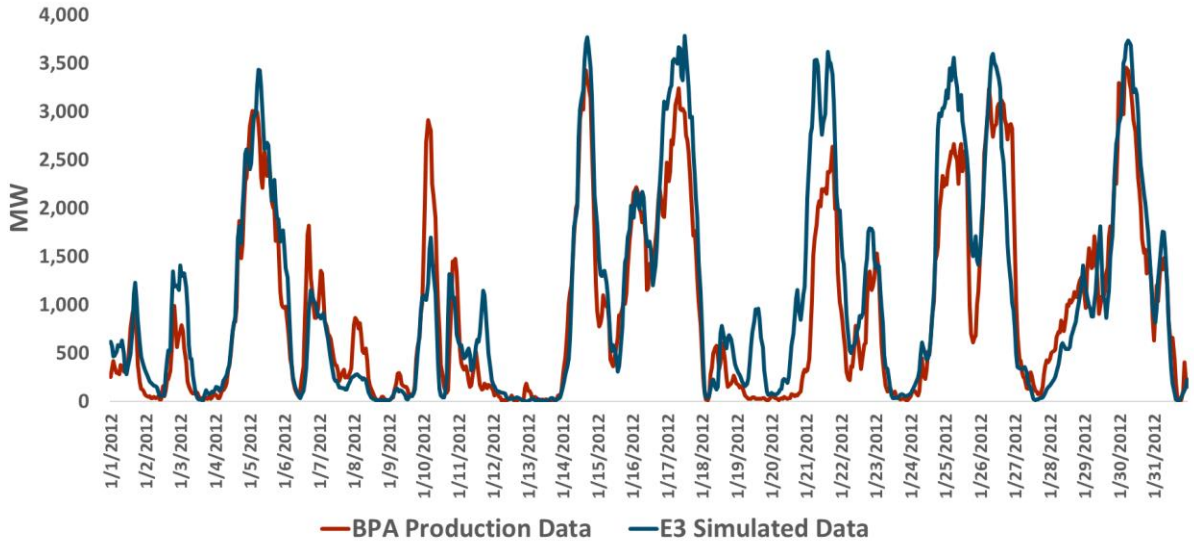


Figure 38: Comparison of Hourly Historical Wind Generation to Simulated Wind Generation for January 2012



C.2 Solar Profiles

C.2.1 SITE SELECTION

Existing solar site locations (latitude, longitude) in the study region are obtained from NWPCC's generator database and WECC's Anchor Data Set. To build new candidate solar resources in the future, the best solar sites in the region are identified based on the highest insolation from the solar maps published by NREL[27] (see Figure 39). While striving to place new candidate wind sites in the sunniest locations, the new candidate sites are spread across each state in a way that they span a large geographical area in order to capture diversity in solar generation (e.g. the likelihood that the sun will be shining in one location even when it is not in another). The future solar sites used in this study are shown in Figure 34.

[27] https://maps.nrel.gov/nsrdb-viewer/

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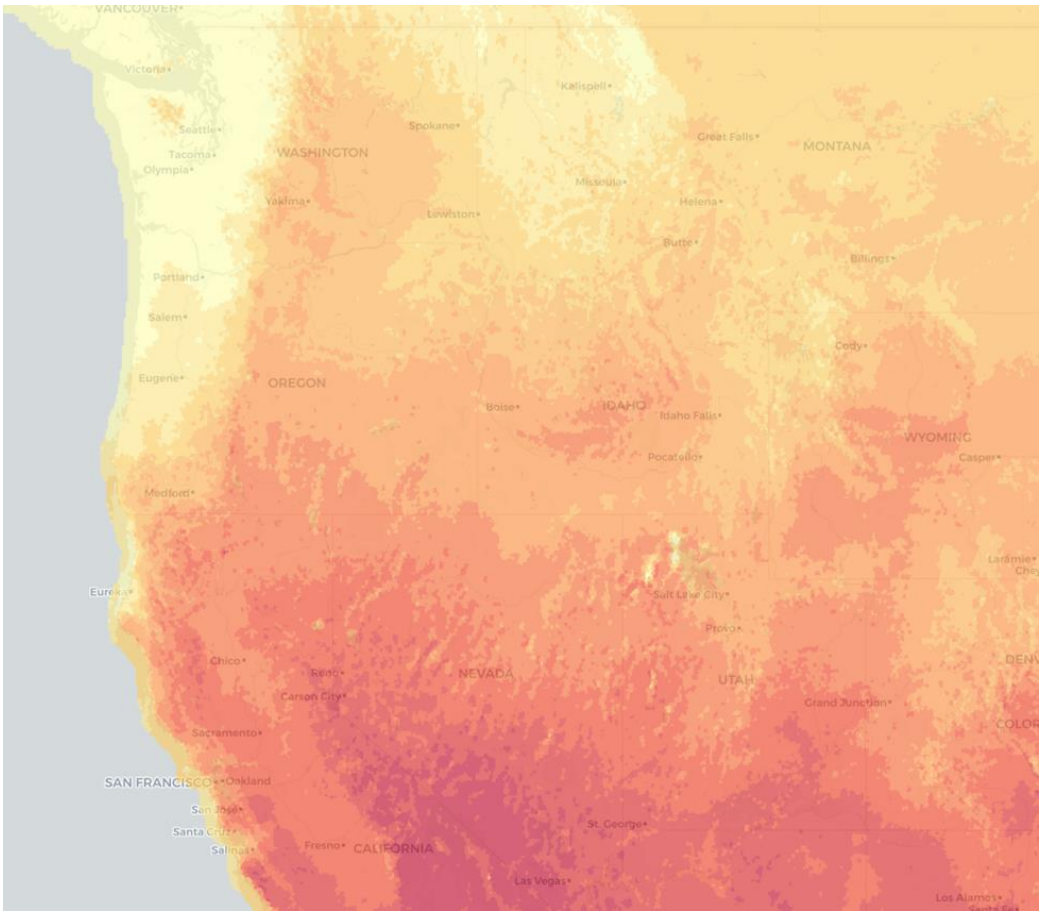
Figure 39: Solar insolation data in the northwest (Source: NREL)



C.2.2 PROFILE SIMULATION

NREL Solar Prospector Database [28] includes historical hourly solar insolation data: global horizontal irradiance (GHI), direct normal irradiance (DNI), diffuse horizontal irradiance (DHI), and solar zenith angle from 1998-2014. This data is downloaded for all each selected site location (both existing and new).

[28] https://nsrdb.nrel.gov/

The hourly insolation data is then converted to hourly production profiles using the NREL System Advisor Model (SAM) simulator. Additional inputs used are tilt, inverter loading ratio and tracking type. All panels are assumed to have a tilt equal to the latitude of their location. The study assumes an inverter loading ratio of 1.3 and that all solar systems are assumed to be single-axis tracking. The NREL SAM simulator produces an hourly time series of generation data that is used to represent the electricity generation from the solar sites in this study.

Forty sites are aggregated to represent the solar candidate resource used in this study. These sites are evenly distributed in the four states of Oregon, Washington, Idaho, and Utah as shown in Figure 34.

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Idaho Power/507
Witness: Jared L. Ellsworth

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

Docket PCN 5

In the Matter of

IDAHO POWER COMPANY'S
PETITION FOR CERTIFICATE OF PUBLIC CONVENIENCE
AND NECESSITY

Princeton Univ., *Net Zero America*
Pathways, Infrastructure, and Impacts
(Dec. 15, 2020)

February 21, 2023


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NET-ZERO AMERICA
POTENTIAL PATHWAYS, INFRASTRUCTURE, AND IMPACTS
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Initiative

Interim Report

Net-Zero America: Potential Pathways, Infrastructure, and Impacts

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December 15, 2020 (v2)

Carbon Mitigation Initiative

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Foreword (1/2)



By John P. Holdren
Professor in the Kennedy School of Government, Department of Earth and Planetary Sciences, and John A. Paulson School of Engineering and Applied Science at Harvard University; formerly (2009-2017) Science Advisor to President Obama and Director of the White House Office of Science and Technology Policy.

December 11, 2020

Long after the terrible challenge of the COVID-19 pandemic has finally been surmounted and (one may hope) greatly improved preparations for inevitable future pandemics have been put in place, the climate-change challenge will be marching on as the 21st century's most dangerous and intractable threat to global society.

It is the most dangerous of threats because the growing human disruption of climate that is already far along puts at risk practically every aspect of our material well-being—our safety, our security, our health, our food supply, and our economic prosperity (or, for the poor among us, the prospects for becoming prosperous).

It is the most intractable of threats because it is being driven, above all, by emissions of carbon dioxide originating from combustion of the coal, oil, and natural gas that still supply eighty percent of civilization's primary energy and over sixty percent of its electricity; and because, for quite fundamental reasons, the shares of electricity and nonelectric energy provided by these fossil fuels cannot be very rapidly reduced, nor can their emissions be easily or inexpensively captured and sequestered away from the atmosphere.

The index used by climate scientists to characterize, in a single number, the state of Earth's climate is the annually and globally averaged temperature of the atmosphere at Earth's surface. The current value is about 1.1°C (2°F) above the value around the beginning of the 20th century. While that increase may strike one initially as modest, it is not. Much like the human body temperature, the average surface temperature of the planet is a very sensitive indicator of the state of a very complex system, with small changes in the index indicative of major disruptions.

At a mere 1°C or so above the average temperature of 120 years ago, the world is experiencing increases in the frequency and intensity of deadly heat waves in many regions; increases in torrential downpours and flooding in many others; large expansions in the annual area burned in regions prone to wildfires (and expansion of wildfires into regions not previously prone to them); an increase in the power of the strongest tropical storms; expanded impacts of pests and pathogens across large parts of the globe; disruptive changes in monsoons; other alterations in atmospheric and oceanic circulation patterns that, together with other impacts, are affecting agriculture and ocean fisheries; an accelerating pace of global sea-level rise; and ocean acidification arising from absorption of some of the excess carbon dioxide in the atmosphere.

The momentum in Earth's climate system and the inertia in society's energy system together ensure that these impacts will grow for some time to come; but how much they grow will depend, above all, on the extent and speed with which human society works to reduce the emissions of carbon dioxide and other heat-trapping gases, to remove them from the atmosphere both biologically and technologically, to adapt our infrastructure and practices to the changes in climate that can no longer be avoided, and, perhaps, to deploy solar-radiation-management technologies to offset some of the heating effect of the heat-trapping gases in the atmosphere (if this approach can be shown to be safe and at least partially effective).

Most of the global community of nations has long embraced a target of limiting the global-average surface temperature increase to 2°C (3.6°) above the "pre-industrial" average. (That average was about the same as the value in the period 1880-1900.) It is clear that this figure would entail climatic disruption and impacts considerably greater than those currently being experienced at just half of that increase. The 2°C figure was agreed not because it would be "safe", but because multiple analyses had indicated that doing much better would be extremely difficult technologically and economically. (Another factor was the view of some that "tipping points" plunging the world into

continues →

Foreword (2/2)



drastically different climate regimes were more likely above 2°C than below; in reality, though, the same argument holds for any other choice of target.) As part of the 2015 Paris Agreement of the Conference of the Parties to the UN Framework Convention on Climate Change, the 2°C target was again officially embraced, but a more ambitious, aspirational target of 1.5°C was added in response to arguments that the likely impacts of 2°C, which science has been bringing into clearer focus, would be intolerable.

In the view of most analysts familiar with the technological and economic challenges of very rapid emission reductions, along with the limitations and uncertainties of natural and technological CO_2-removal methods and solar-radiation management, holding the temperature increase to 1.5°C target is very unlikely to be achievable. A large part of the analytical effort on pathways to deep emissions reduction continues to be focused, therefore, on investigating how reductions consistent with a 2.0°C target might be achieved. In any case, though, it is much more important now to focus on what strategies for technological innovation and what policies will move the world more rapidly onto a deep-reductions trajectory than to try to agree on exactly what ultimate temperature limit the world will be able to stay below.

A larger point related to this last one is that the benefit of any attempt to identify and model pathways into the energy-climate future is not in predicting the most likely path on which that future will unfold. It is most improbable that any model will succeed in doing that, given the many respects in which the future is simply not predictable. Rather, models of the ways in which the energy-climate future might evolve are most useful if they can clarify possibilities, using transparent assumptions and algorithms, in ways that help other analysts, policy makers, and publics understand the consequences of different assumptions and choices and, most importantly, help us all shape policies and technological-innovation strategies that can be adjusted over time to respond to new realities as they unfold.

It has been clear for two decades or more that, for the industrialized countries to do something approaching a responsible share of a global effort to limit the average surface temperature increase to 2.0°C, they would need to reduce their emissions of heat-trapping gases by 80 to 100 percent by around 2050. Each year that has passed without countries taking steps of the magnitude needed to move expeditiously onto a trajectory capable of achieving such a goal has increased the challenge that still lies ahead.

At the same time, observations of actual harm from climate change and a continuing flow of bad news from climate science about likely future impacts has increased the sense of urgency in the knowledgeable community, while continuing advances in energy technology have engendered a degree of optimism about what emission reductions might be possible and affordable. The result has been an increasing flow of (mostly) increasingly sophisticated modeling studies of how emissions of CO_2 and other heat-trapping gases might be reduced to near zero by 2050. In the United States, such studies have been conducted by the federal government (not always published), by the National Academies, by national laboratories, by companies, by universities, by NGOs, and by consortia.

I believe that this Princeton Study, *Net Zero America: Potential Pathways, Infrastructure, and Impacts*, sets an entirely new standard in this genre. The superb Princeton team—led by Eric Larson, Jesse Jenkins, and Chris Greig—has done an absolutely remarkable amount of new work, developing new models and new data to provide an unprecedented degree of clarity and granularity about possible pathways to mid-century "net zero" for this country. They have analyzed technological possibilities, as currently understood, in great detail; they have examined the "co-benefit" of reduced disease impacts from conventional air pollutants when fossil-fuel use is reduced; they have examined the employment consequences of alternative trajectories; and, perhaps most importantly, they have called attention to the most important areas where policy measures are needed to enhance and preserve the nation's options going forward, as events evolve and understandings grow.

None of the Princeton scenarios will prove to be "right", but together they provide a compelling picture of possible paths forward. Everybody seriously interested in the crucial question of this country's energy-climate future—not least the new Biden-Harris administration—needs to understand the findings of this extraordinary study.

*****

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Preface and Acknowledgments



This *Net Zero America* study aims to inform and ground political, business, and societal conversations regarding what it would take for the U.S. to achieve an economy-wide target of net-zero emissions of greenhouse gases by 2050. Achieving this goal, i.e. building an economy that emits no more greenhouse gases into the atmosphere than are permanently removed and stored each year, is essential to halt the buildup of climate-warming gases in the atmosphere and avert costly damages from climate change. A growing number of pledges are being made by major corporations, municipalities, states, and national governments to reach net-zero emissions by 2050 or sooner. This study provides granular guidance on what getting to net-zero really requires and on the actions needed to translate these pledges into tangible progress.

The work outlines five distinct technological pathways all of which achieve the 2050 goal and involve spending on energy in line with historical spending as a share of economic activity, or between 4-6% of gross domestic product (GDP). We are agnostic as to which of these pathways is "best", and the final path the nation takes will no doubt differ from all of these. Our goal is to provide confidence that the U.S. now has multiple genuine paths to net-zero by 2050 and to provide a blueprint for priority actions for the next decade. These priorities include accelerating deployment at scale of technologies and solutions that are mature and affordable today and will have high value regardless of what path the nation takes, as well as a set of actions to build key enabling infrastructure and improve a set of less mature technologies that will help complete the transition to a net-zero America.

With multiple plausible and affordable pathways available, the societal conversation can now turn from "if" to "how" and focus on the choices the nation and its myriad stakeholders wish to make to shape the transition to net-zero. These conversations will need to be sensitive to the different values and priorities of diverse communities. That requires insight on how the nation will be reshaped by different paths to net-zero, and the benefits, costs, and challenges for specific locations, industries, professions, and communities. Supporting these decisions requires analysis at a visceral, human scale.

The original and distinguishing feature of this *Net Zero America* study is thus the comprehensive cataloging across all major sectors at high geospatial and temporal resolution of the energy infrastructure deployments and related capital expenditures required during a net-zero transition. This granularity allows us to assess implications for land use, employment, air pollution, capital mobilization, and incumbent fossil fuel industries at state and local levels. The high resolution analysis is aimed at helping inform federal and state policy choices and private-sector decision making in support of a transition to net-zero by 2050.

During this two-year research effort, the authors had many informative discussions with individuals in environmental research and advocacy organizations, oil and gas companies, renewable energy companies, national labs, industry trade organizations, universities, and elsewhere. The authors thank those individuals for their time and interest. The authors also thank the approximately 300 stakeholders who attended briefings where preliminary study results were presented. The feedback received at and following those briefings have helped shape the contents of this report. Of course, any errors or omissions in this study are the responsibility of the authors alone, as are any views or recommendations expressed herein.

For funding support, the authors thank the Andlinger Center for Energy and the Environment, BP and the Carbon Mitigation Initiative within Princeton's High Meadows Environmental Institute, ExxonMobil, and the University of Queensland.

Executive Summary (1/9)

Synopsis



A growing number of pledges are being made by major corporations, municipalities, states, and national governments to reach net-zero emissions by 2050 or sooner. This study provides granular guidance on what getting to net-zero really requires and on actions needed to translate these pledges into tangible progress.

Using state-of-the-art modeling tools, this study provides five different technologically and economically plausible energy-system pathways for the U.S. to reach net-zero emissions by 2050. We then further refine these model results to provide highly-resolved mapping, sector-by-sector, of the timing and spatial distribution of changes in energy infrastructure, capital investment, employment, air pollution, land use, and other key outcomes at a state and local level.

We find that each net-zero pathway results in a net increase in energy-sector employment and delivers significant reductions in air pollution, leading to public health benefits that begin immediately in the first decade of the transition. The study also concludes that a successful net-zero transition could be accomplished with annual spending on energy that is comparable or lower as a percentage of GDP to what the nation spends annually on energy today. However, foresight and proactive policy and action are needed to achieve the lowest-cost outcomes.

Building a net-zero America will require immediate, large-scale mobilization of capital, policy and societal commitment, including at least $2.5 trillion in additional capital investment into energy supply, industry, buildings, and vehicles over the next decade relative to business as usual. Consumers will pay back this upfront investment over decades, making the transition affordable (total annualized U.S. energy expenditures would increase by less than 3% over 2021-2030), but major investment decisions must start now, with levels of investments ramping up throughout the transition.

Each transition pathway features historically unprecedented rates of deployment of multiple technologies. Impacts on landscapes, incumbent industries and communities are significant and planning will need to be sensitive to regional changes in employment and local impacts on communities.

Executive Summary (2/9)
Motivation, Objectives, Approach



Motivation

- Growing government and corporate net-zero-by-2050 pledges, but little detail on execution, costs and impacts.

Project objectives

- Temporally and spatially resolve scales, costs, and pacing of required physical, institutional, and human-resource efforts to reach net-zero by 2050 across the continental US.
- Focus on articulating a granular picture of prospective transitions. Identify potential bottlenecks to success.
- No advocacy of specific policies, but provide actionable details for policy- and decision-making; engage with stakeholders.

Analytical approach

- Start with energy service demands projected to 2050 by US EIA (AEO 2019) for 14 regions across continental US.
- Construct multiple (diverse) technology pathways for meeting demands, while reaching net-zero emissions in 2050.
  - End-use technologies to meet service demands are exogenously specified in 5-year time steps. This determines final energy demands that must be delivered by the energy supply system.
  - Optimization model finds the energy supply mix that minimizes the 30-year societal NPV of total energy-system costs. The model has perfect foresight and seamless integration between all sectors.
- **Modeling results are downscaled from 14 regions to state or sub-state geographies to quantify local plant and infrastructure investments, construction activities, land-use, and jobs impacts, 2020 - 2050.**

Executive Summary (3/9)
Six pillars are needed to support the transition to net-zero



1. **End-use energy efficiency and electrification**
2. **Clean electricity: wind & solar generation, transmission, firm power**
3. **Bioenergy and other zero-carbon fuels and feedstocks**
4. **CO_2 capture, utilization, and storage**
5. **Reduced non-CO_2 emissions**
6. **Enhanced land sinks**

Executive Summary (4/9)

Six pillars expand rapidly for 3 decades. By 2050:



1. Efficiency & Electrification

Consumer energy investment and use behaviors change

- 300 million personal EVs
- 130 million residences with heat pump heating

Industrial efficiency gains

- Rapid productivity gain
- EAF/DRI steel making

2. Clean Electricity

Wind and solar

- Rapidly site 10s-100s of GW per year, sustain for decades
- 3x to 5x today's transmission

Nuclear

- In RE- scenario site up to 250 new 1-GW reactors (or 3,800 SMRs).
- Spent fuel disposal.

NGCC-CCS

- In RE-, 300+ plants (@750 MW)

Flexible resources

- Combustion turbines w/high H_2
- Large flexible loads: electrolysis, electric boilers, direct air capture
- 50 - 180 GW of 6-hour batteries

3. Zero-Carbon Fuels

Major bioenergy industry

- 100s of new conversion facilities
- 620 million t/y biomass feedstock production (1.2 Bt/y in E- B+)

H_2 and synfuels industries

- 8-19 EJ H_2 from biomass with CCS (BECCS), electrolysis, and/or methane reforming
- Largest H_2 use is for fuels synthesis in most scenarios

4. CO_2 capture & storage

Geologic storage of 0.9 – 1.7 $GtCO_2$/y

- Capture at ~1,000+ facilities
- 21,000 to 25,000 km interstate CO_2 trunk pipeline network
- 85,000 km of spur pipelines delivering CO_2 to trunk lines
- Thousands of injection wells

5. Non-CO_2 Emissions

Methane, N_2O, Fluorocarbons

- 20% below 2020 emissions (CO_{2e}) by 2050 (30% below 2050 REF).

6. Enhanced land sinks

Forest management

- Potential sink of 0.5 to 1 $GtCO_{2e}$/y, impacting ½ or more of all US forest area (≥ 130 Mha).

Agricultural practices

- Potential sink ~0.20 $GtCO_{2e}$/y if conservation measures adopted across 1 – 2 million farms.

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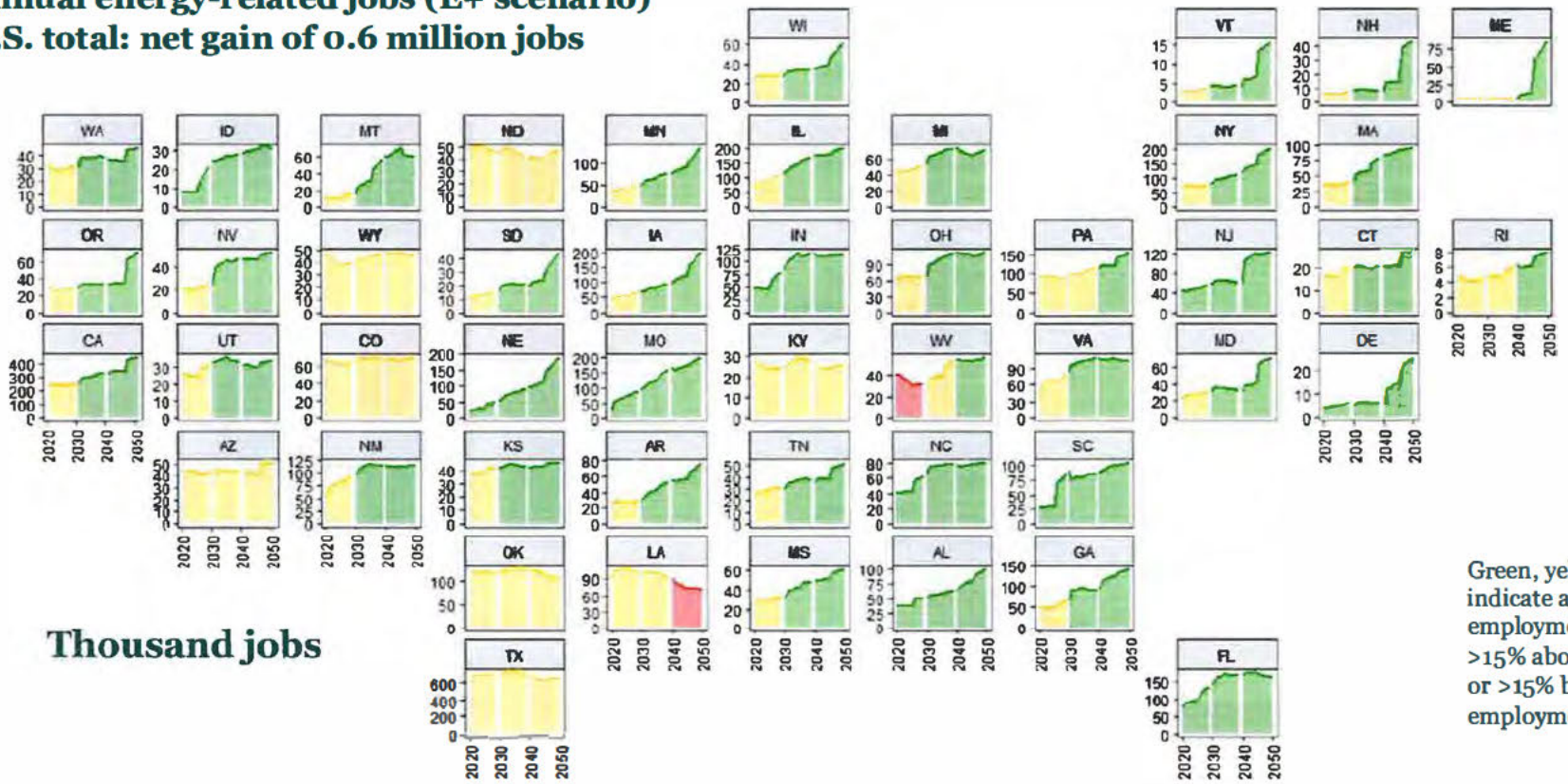
Executive Summary (5/9)

Net increase of ½ to 1 million jobs over REF in the 2020s.

Annual energy-related jobs (E+ scenario)
U.S. total: net gain of 0.6 million jobs

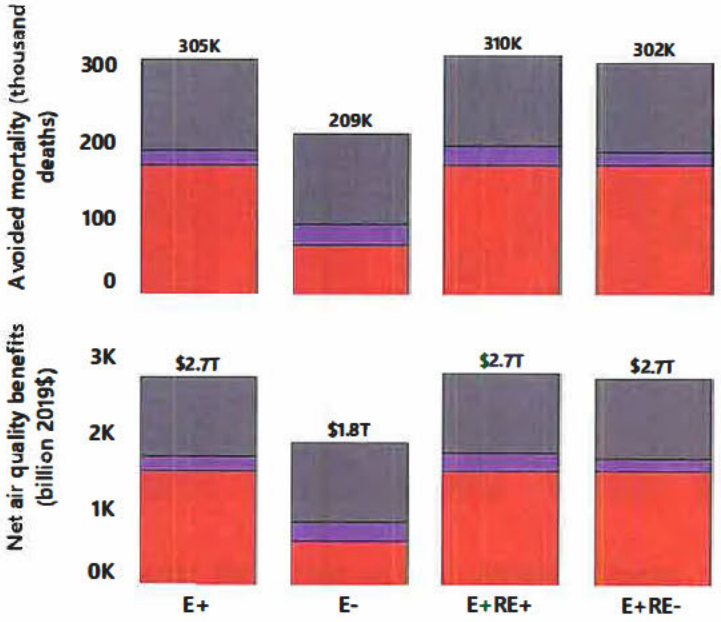


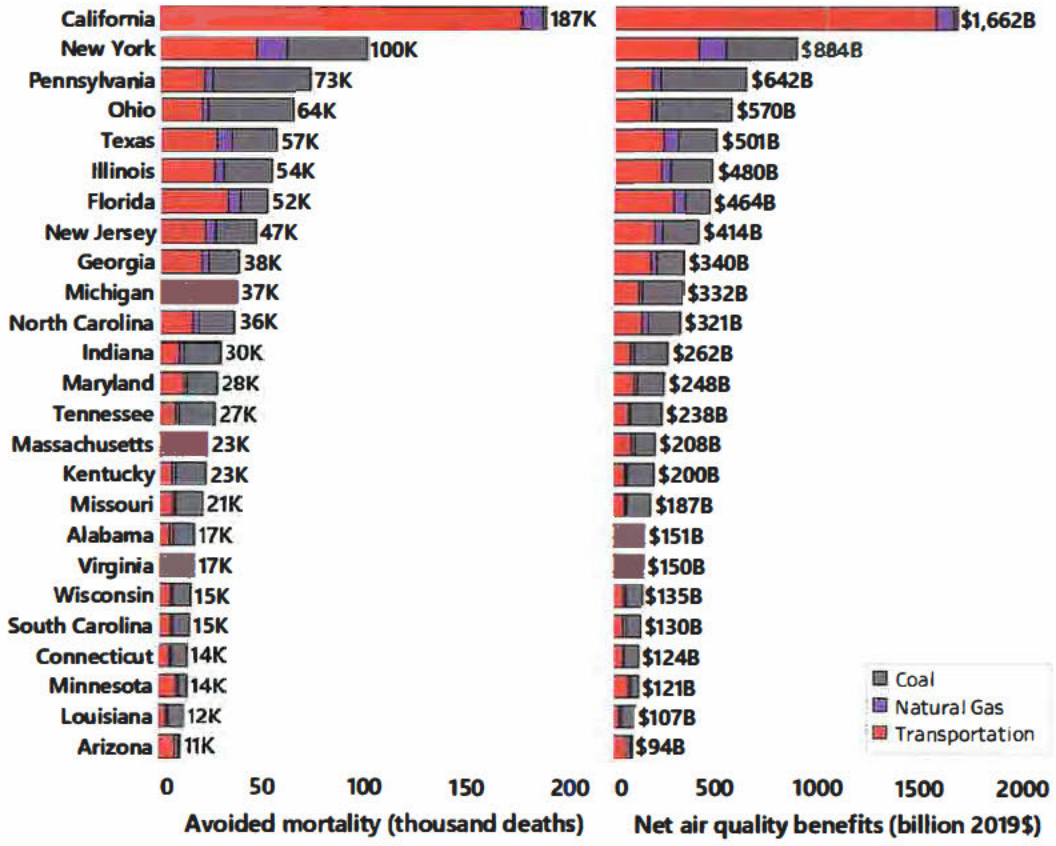
Green, yellow, and red indicate average annual employment in a decade is >15% above, within ± 15%, or >15% below 2021 employment, respectively.

Executive Summary (6/9)

Big air pollution health benefits starting in 2020s

Cumulative air quality benefits, 2020 – 2050, include 200,000 to 300,000 premature deaths avoided (2 - 3 T$ estimated damages)





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Executive Summary (7/9)

Net-Zero America by 2050 is possible and affordable if:



- **Technology and infrastructure are deployed at historically unprecedented rates** across most sectors.
- **Expansive impacts on landscapes and communities** are mitigated and managed to secure **broad social license and sustained political commitment.**
- **Large amounts of risk-capital** are mobilized rapidly by government and private sectors.
- **Electrification uptake by consumers is rapid** across all states (EV's, space heating, etc.).
- **Industry transforms** (electrification, hydrogen, low-carbon steel and cement, etc.)
- **Ambitious expansion of low-carbon technology starts now**, with 2020s used to:
  - Increase and accelerate deployment of wind and solar generation, EVs, heat pumps
  - Invest in critical enabling infrastructure (EV chargers, transmission, CO_2 pipelines)
  - Demonstrate and mature technology options for rapid deployment in the 2030's and 2040's

Executive Summary (8/9)
A Blueprint for the Next Decade



This study provides a blueprint for action, including a set of robust measures needed this decade to get on track to net-zero emissions by 2050, regardless of which net-zero pathway the country follows in the longer term. This implies that big energy investments can be made this decade with confidence that they will deliver value over the long term.

Priority actions for now to 2030 include:

- Get roughly 50 million electric cars on the road and install 3 million or more public charging ports nationwide
- Increase by more than double the share of electric heat pumps for home heating (23% vs. 10% today) and triple the use of heat pumps in commercial buildings
- Grow wind and solar electricity generating capacity fourfold (to approximately 600 gigawatts), enough to supply roughly half of U.S. electricity (vs. 10% today)
- Expand high-voltage transmission capacity by roughly 60% to deliver renewable electricity to where it is needed
- Increase annual uptake of carbon stored permanently in forests and agricultural soils by 200 million metric tons of CO_2-e
- Reduce non-CO_2 greenhouse gas emissions, including methane, nitrous oxides and hydrofluorocarbons, by at least 10%

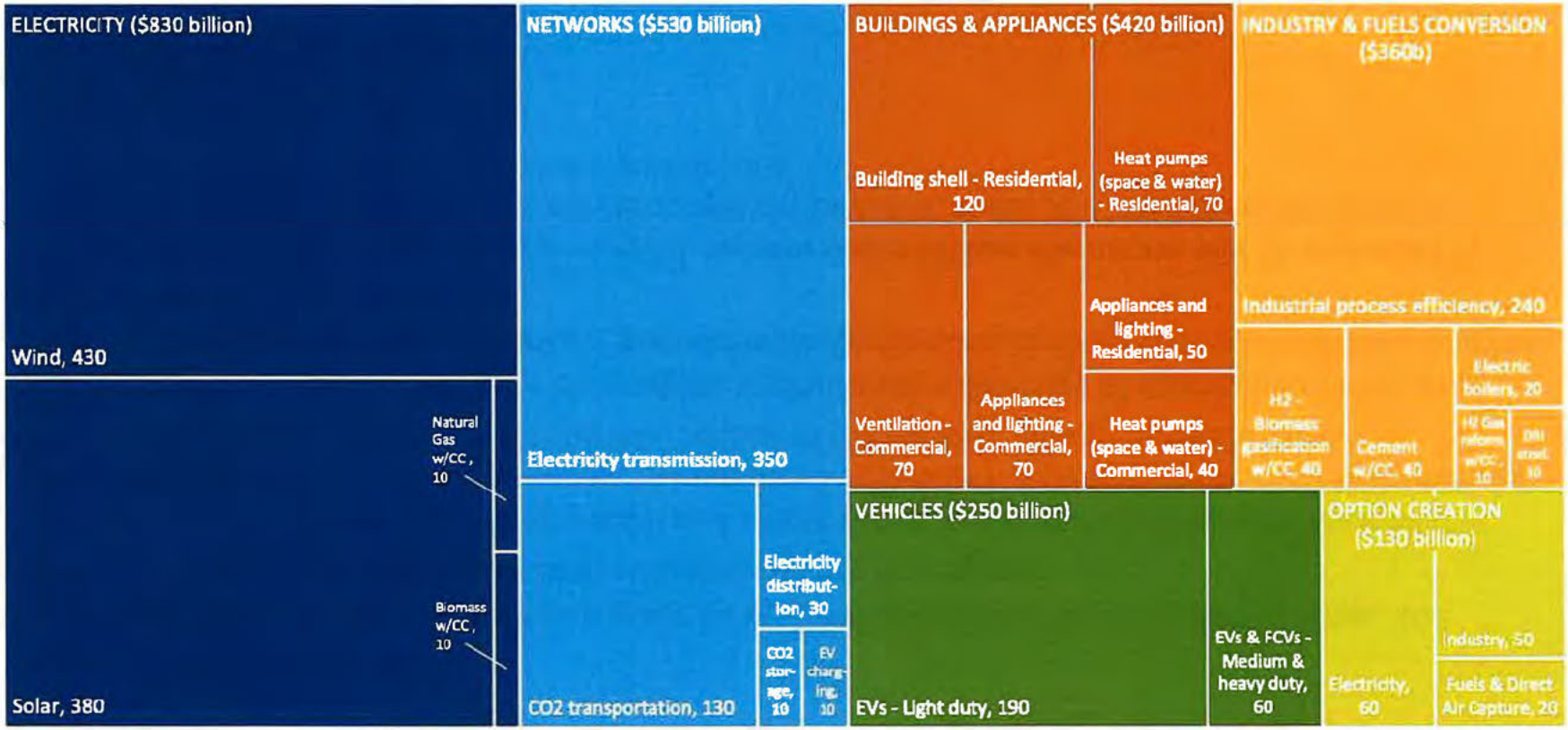
Actions for the 2020s also include a set of important investments in enabling infrastructure and innovative technologies to create real options to complete the transition to net-zero beyond 2030:

- Plan and permit additional electricity transmission to enable further wind and solar expansion
- Plan and begin construction of a nationwide CO2 transportation network and permanent underground storage basins
- Invest in maturing key technologies to make them cheaper, scalable and ready for widespread beyond 2030, including: carbon capture for a various industrial processes and power generation technologies; low-carbon industrial processes; clean "firm" electricity technologies, including advanced nuclear, advanced geothermal, and hydrogen combustion turbines; advanced bioenergy conversion processes & high yield bioenergy crops; hydrogen and synthetic fuel production from clean electricity, and from biomass and natural gas with carbon capture; and direct capture of CO2 from the air.

Executive summary (9/9)

Added capital invested (vs. REF) in 2020s is at least $2.5T

Total additional capital invested, 2021-2030, by sector and subsector for a net-zero pathway vs. business as usual (billion 2018$)



Includes capital invested pre-financial investment decision (pre-FID) and capital committed to projects under construction in 2030 but in-service in later years.
All values rounded to nearest $10b and should be considered order of magnitude estimates. Incremental capital investment categories totaling less than $5B excluded from graphic.
Other potentially significant capital expenditures *not* estimated in this study include establishment of bioenergy crops and decarbonization measures in other industries besides steel and cement, non-CO_2 GHG mitigation efforts, and establishing enhanced land sinks.

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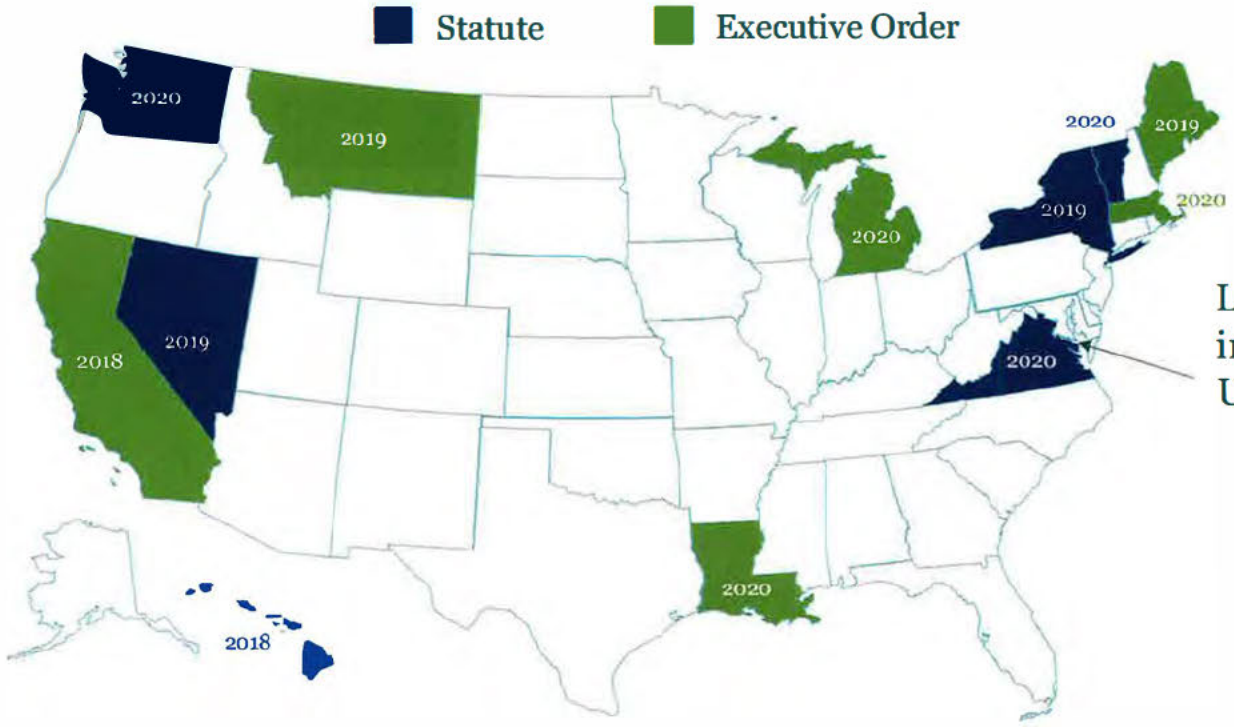
Net-Zero America: Project motivation



Summary of this section

- A growing number of pledges are being made by major corporations, municipalities, states, and national governments to reach net-zero emissions by 2050 or sooner.
- Achieving net-zero emissions for the nation as a whole presents a major challenge for reasons that include the high level of emissions today, the country's still-heavy dependence on fossil hydrocarbon fuels, and the diverse and firmly established nature of the existing energy infrastructure.
- This study is motivated to help provide analysis that informs a diversity of stakeholders who must engage to achieve a Net-Zero America – governments, businesses, civil-society organizations, and the public at large.
- The study aims to provide insights at visceral, human scales of how the nation will be reshaped by different technological pathways to net-zero, and the benefits, costs, and challenges for specific locations, industries, professions, and communities.

A dozen states have pledged net-zero by 2050 (and counting)



Legislation introduced in both houses of US Congress

The Clean Economy Act of 2020
NET-ZERO EMISSIONS by 2050

Last updated November 15, 2020. Source: https://www.c2es.org/content/state-climate-policy/

Growing number of companies have pledged net-zero by 2050



Electric Utilities

Xcel Energy
PSEG
Edison International — Energy for What's Ahead
Southern Company
Duke Energy
DTE Energy
Dominion Energy
nrg
aps
Consumers Energy
Green Mountain Power
IDACORP — Idaho Power — An IDACORP Company
Hawaiian Electric
nationalgrid
Eversource
PSE Puget Sound Energy
MGE — Madison Gas and Electric
Avista
AVANGRID
FirstEnergy

For others, see https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/

Oil & Gas*

Repsol
Shell
bp
OXY

* These companies' pledges include scope 3 emissions.

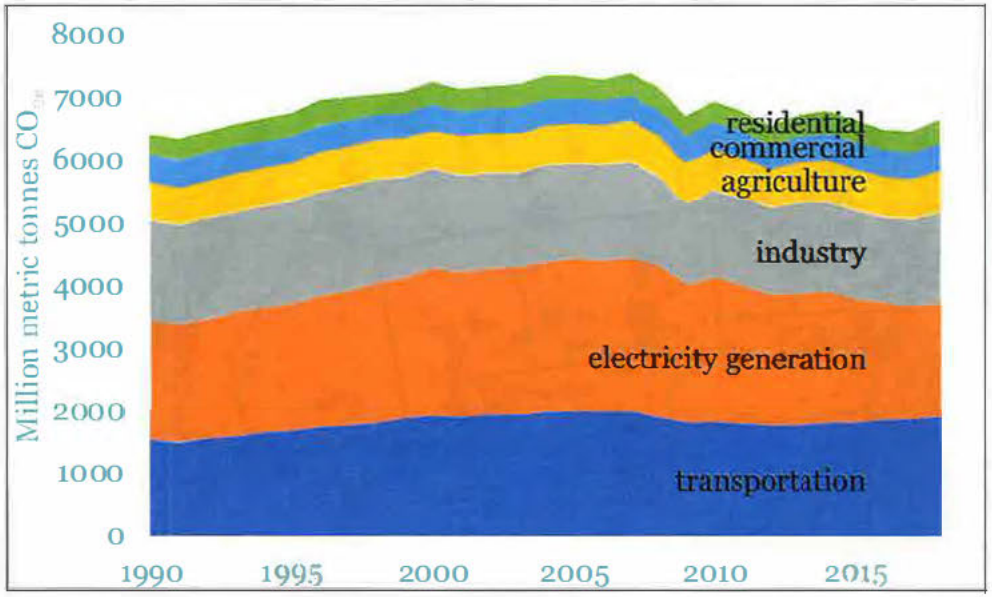
Materials

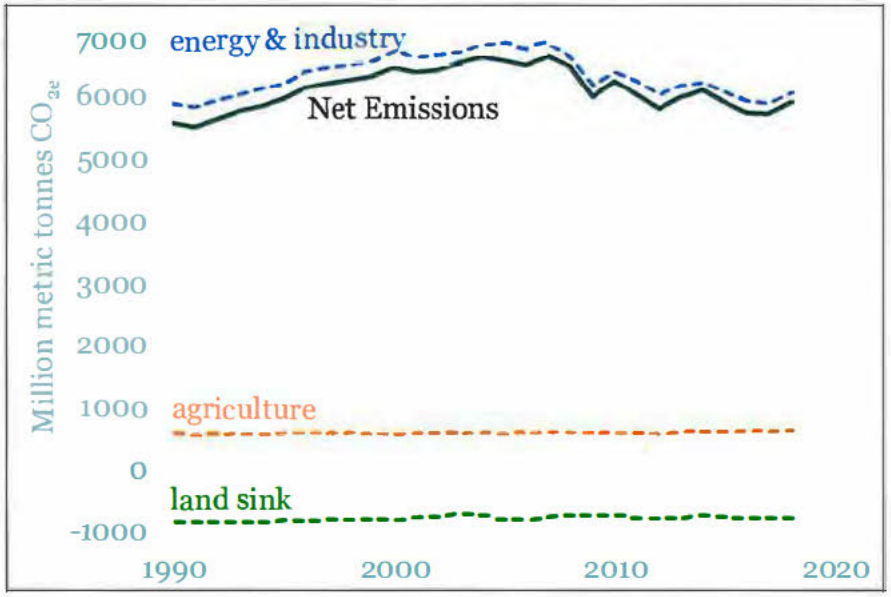
Vale
HeidelbergCement
ArcelorMittal
thyssenkrupp

Airlines

Delta
Qantas
jetBlue
Iberia
Finnair
Qatar Airways
Royal Air Maroc
Airlines
American Airlines
Japan Airlines
British Airways
Cathay Pacific
malaysia airlines
SriLankan Airlines
Royal Jordanian

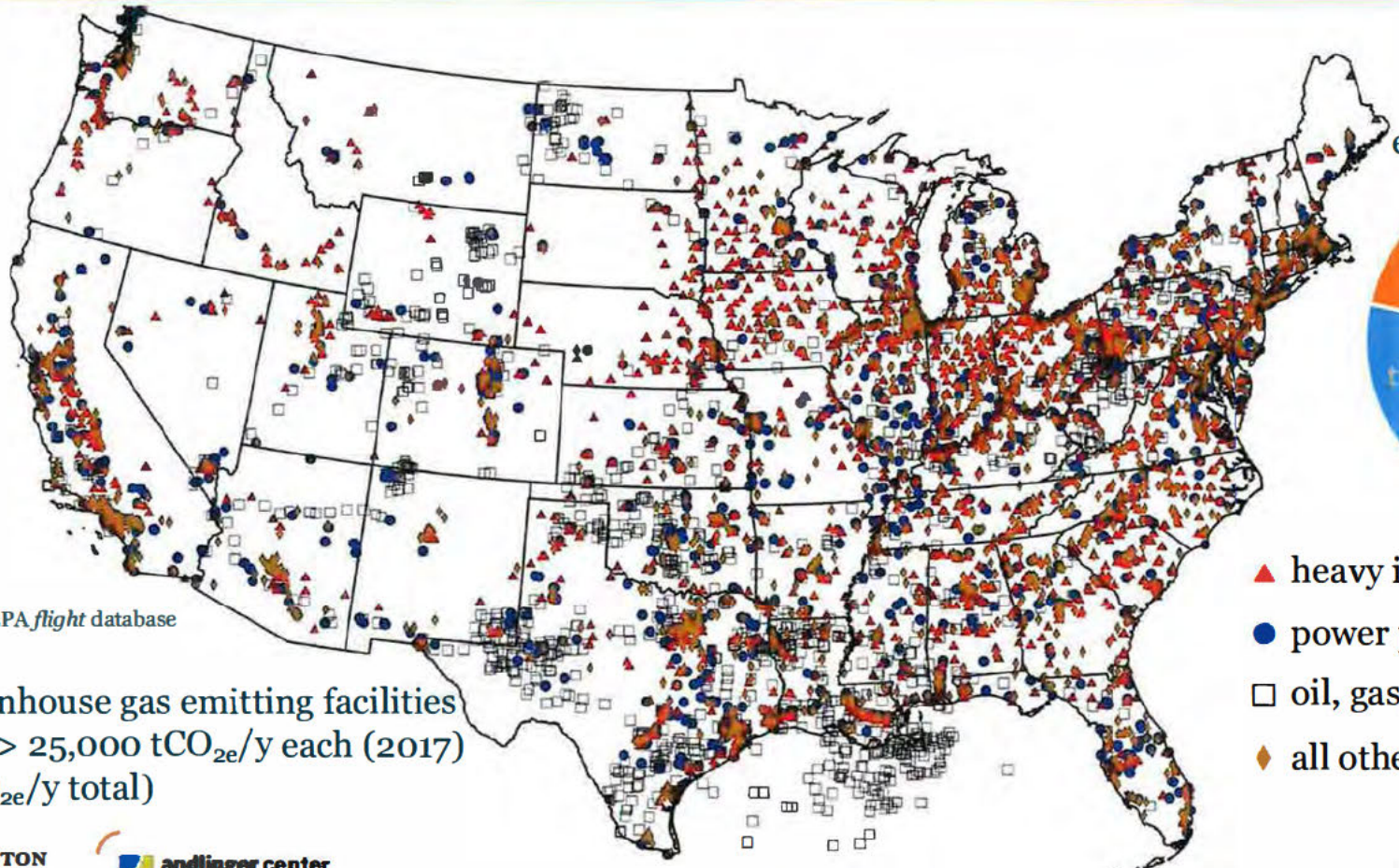
Sizing up the challenge: Net emissions today are ~6 $GtCO_{2e}/y$





EPA GHG Inventory

Sizing up the challenge: Industrial facilities and power plant emission sources are widely dispersed today



EPA *flight* database

7,515 greenhouse gas emitting facilities reporting > 25,000 tCO_{2e}/y each (2017) (~ 3 $GtCO_{2e}$/y total)

Economy-wise emissions by sector



- ▲ heavy industries
- ● power plants
- □ oil, gas, coal operations
- ♦ all other industries

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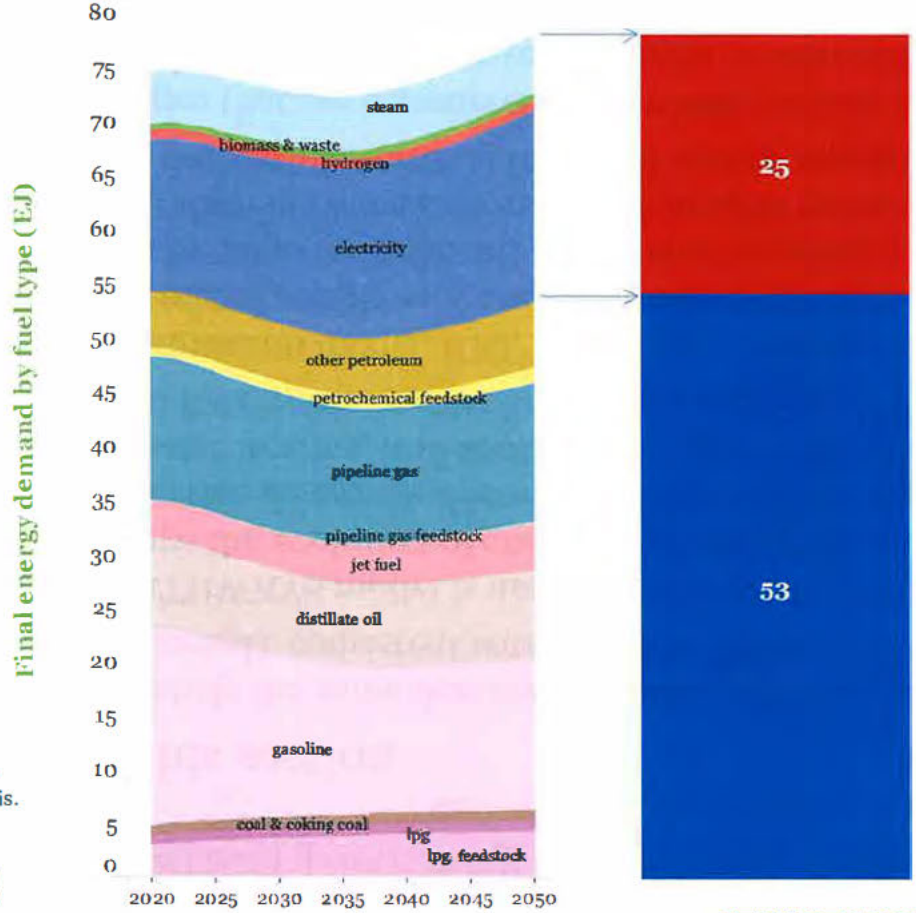
Sizing up the challenge: 2/3 of final energy today is hydrocarbons



REFERENCE (EIA AEO 2019)



~ 25 EJ_{HHV} of final energy demand (1/3 of total) are non-hydrocarbon and could be met using **zero carbon electricity**

~ 53 EJ_{HHV} (2/3 of total) are hydrocarbons, for which there are the following approaches:

- **Energy productivity (efficiency, mode shifting, conservation)**
- **Electrification**
- **Drop-in zero-carbon fuels**
- **Fossil fuel use with CO_2 capture + some negative emissions to offset**

Note: All fuel values reported in this slide pack are on HHV basis.

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Decarbonization pathway modeling methodology & key assumptions



Summary of this section

- All scenarios satisfy the same demand for energy services (e.g. vehicle miles traveled, area of building space heated/cooled), consistent with U.S. EIA (*Annual Energy Outlook 2019* Reference scenario).
- The Energy PATHWAYS model is used to construct two different demand-side scenarios, specifying in 5-year time steps the evolution of energy consuming vehicles, appliances, building stock, etc. to meet those energy service demands: one with nearly complete electrification of most transportation and building and water heating, and another with slower electrification. These scenarios determine final energy demand for electricity, gasoline, pipeline gas, and other fuels.
- A detailed optimization model, RIO, is then run to determine the lowest-cost (30-year societal net present value) mix of supply-side and network infrastructure to meet demand for fuels and reach net zero emissions by 2050 (with linearly declining emissions). The model has perfect foresight and seamless integration between sectors, and it models power sector operations at hourly resolution for 41 representative days, while tracking fuels and energy storage volumes across days.
- Only technologies that are commercially available or have been demonstrated at commercial scale are considered; no fundamentally new technologies or scientific breakthroughs are assumed.
- Modeling results are only the beginning of the analysis, and serve as inputs for customized highly-resolved "downscaling" analysis performed sector-by-sector (and reported in subsequent sections).

Pathway modeling tools

Modeling performed by EVOLVED ENERGY RESEARCH

EnergyPATHWAYS
scenario tool*

Scenario analysis tool used to develop economy-wide energy demand scenarios.

EnergyPATHWAYS produces parameters for RIO's supply-side optimization:

- Demand for fuels (electricity, pipeline gas, diesel, etc.) over time
- Emissions caps by year
- Hourly electricity load shape

RIO
optimization tool**

Cost-minimized portfolios of low-carbon technology deployment for electricity generation and balancing, alternative fuel production, and direct air capture.

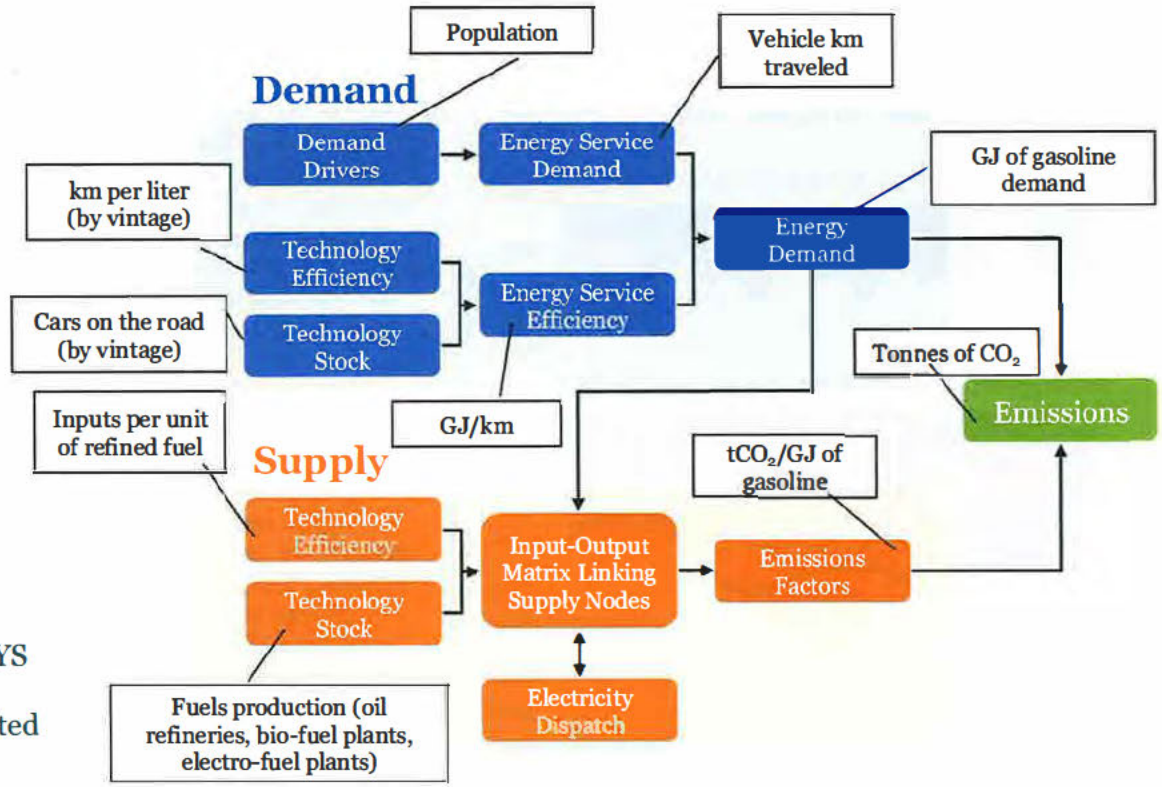
RIO returns supply-side decisions to EP for cost and emissions accounting:

- Electricity sector portfolios, including renewable mix, energy storage capacity & duration, capacity for reliability, transmission investments, etc.
- Biomass allocations for fuels

* Open-source software.

** Evolved Energy Research proprietary.

LIGHT DUTY VEHICLES EXAMPLE



Note: By convention, all fuel values input to EnergyPATHWAYS and RIO are expressed as higher heating values (HHV); all outputs are likewise expressed as HHVs. All fuel values reported in this slide deck are HHVs, unless stated otherwise.

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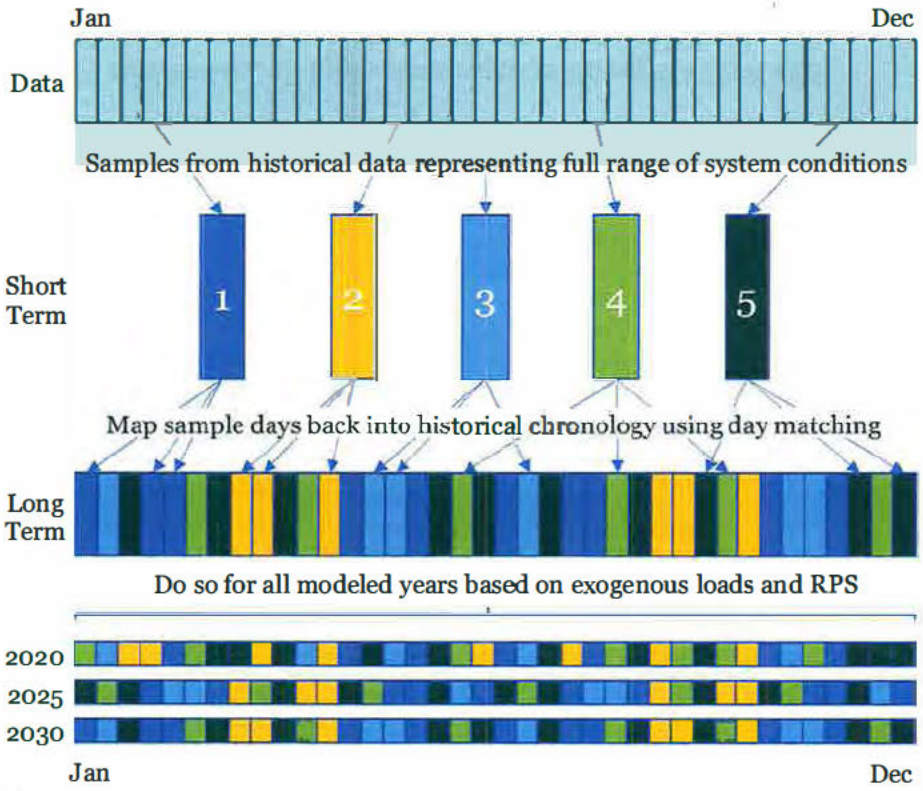
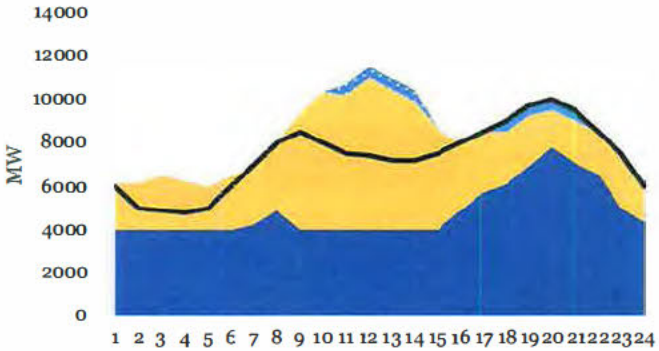
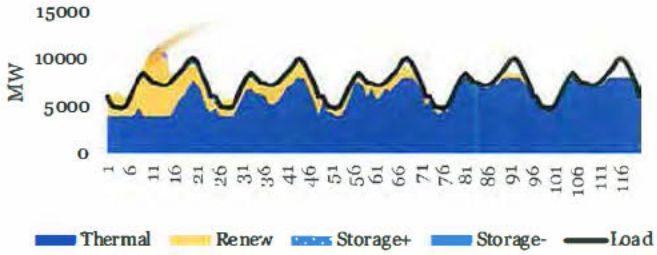
RIO power-sector temporal modeling: Hourly operations for 41 sample days; long-term operations over full chronology

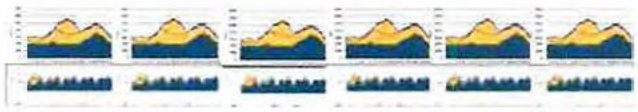


Detailed short term dispatch for every sample day. Dispatch decisions are the same across all days represented by the same sample



Time sequential long-term storage operations across sample day dispatches. Long-term dispatch decisions are different across days, based on long term needs





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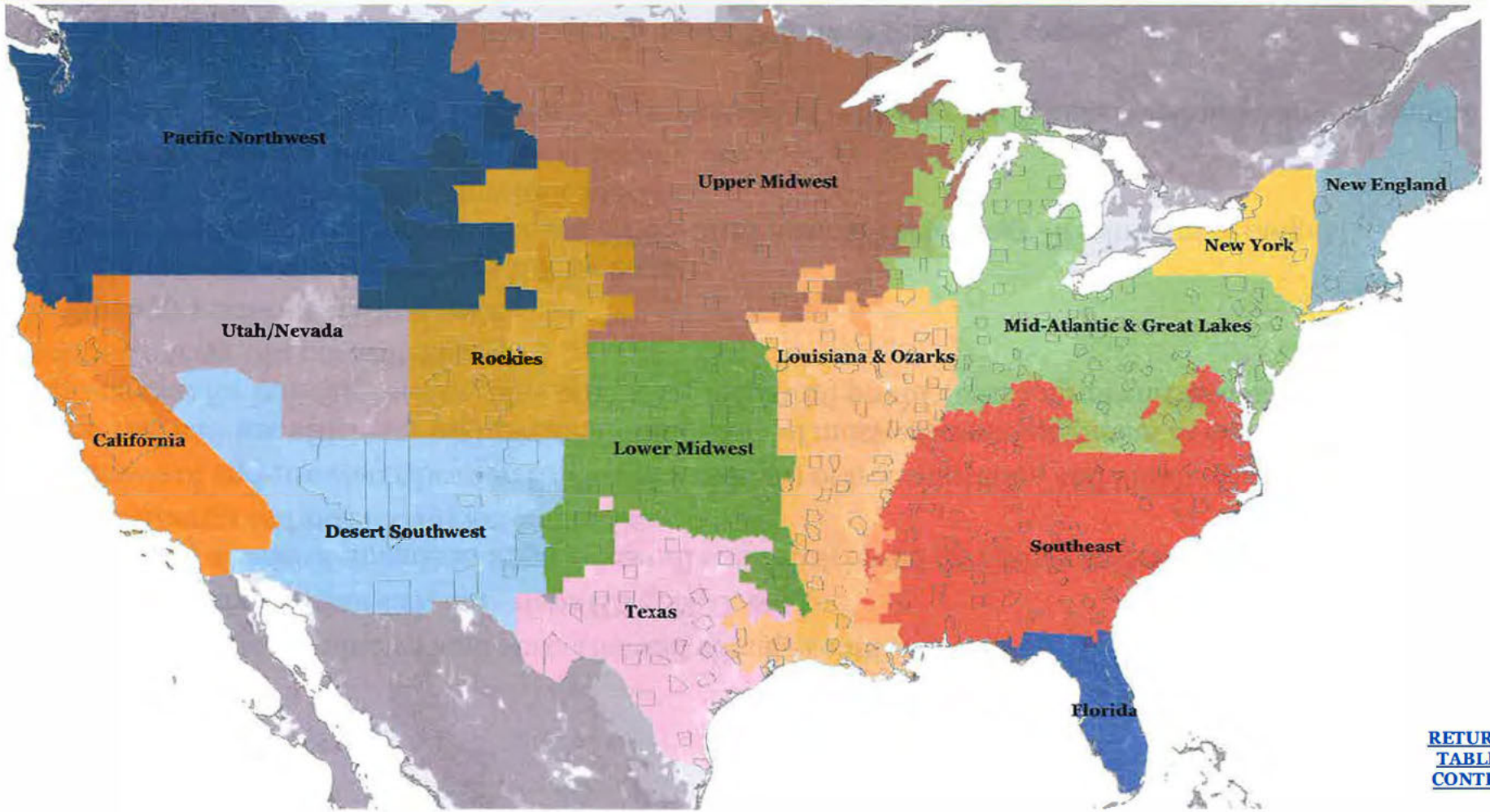
Model inputs are at state level; outputs are reported for 14 zones (consolidated eGRID regions)



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Key assumptions



- Concerted efforts to enhance land sinks (natural climate solutions).
- Progress in reducing non-CO_2 emissions (CH_4, N_2O, etc.).
- Same energy-service demands to 2050 across all scenarios, based on Energy Information Administration *Annual Energy Outlook* (2019) Reference Case
- Two levels of end-use electrification (high and less-high) of transportation and buildings.
- Same-fuel end-use efficiency improvements: adoption of most-efficient equipment at end-of-life replacement for buildings sector, plus aggressive industrial productivity improvements and reductions in aviation energy use per seat-km.
- Technology performance and costs:
  - Light duty EV capex parity with ICE by 2030
  - Power generation and battery storage: NREL 2019 Annual Technology Baseline (mid-range).
  - Biofuels, H_2, synfuels from literature sources.
  - Direct air capture: American Physical Society, 2011.
- Biomass supply: DOE "Billion Ton Study" + conversion of ethanol-corn & Conservation Reserve Program lands.
- CO_2 transport and storage costs developed in consultation with industry experts.
- Oil and gas prices are AEO 2019 lowest-price projections.

Key assumptions

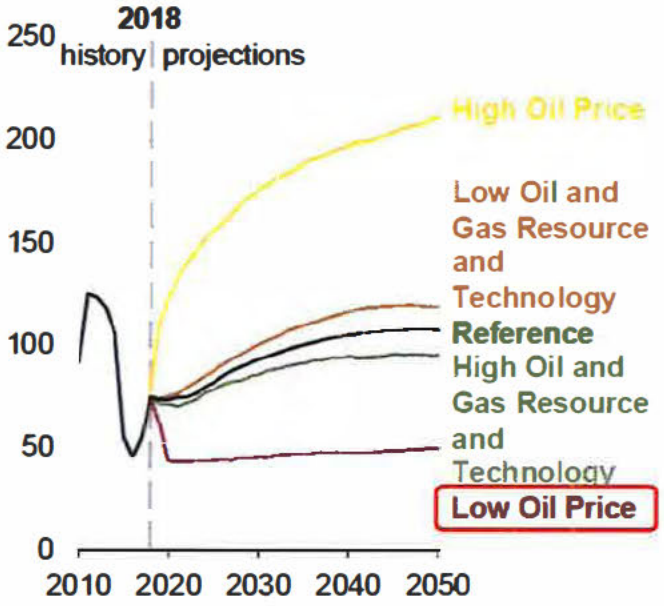


CO_2 emissions	
Land CO_2 in 2050	- 0.85 Gt/y (- 0.7 Gt/y today and declining)
Non-CO_2 in 2050	1 $GtCO_{2e}$/y (50% reduction from today)
Energy/Industry CO_2	- 0.17 GtCO2 in 2050
Technology installed capital costs in 2016$ (some later slides express values in 2018$, assuming 4% escalation from 2016)	
Utility solar, $/$kW_{AC}$	$1,400/kW (2020) → $900/kW (2050) [including grid connection costs]
Onshore wind, $/kW	$1,500 - $2,700/kW (2020) → $1000 - $1,900/kW (2050) [including grid connection costs]
Nuclear power, $/kW	$6,600/kW (2020) → $5,500/kW (2050)
NG power w/CC, $/kW	NGCC-CC, $2,200 (2020) → $1,700 (2050). NG-Allam (99% capture, available from 2030), $2,300/kW.
H_2 capex, $/$kW_{H2HHV}$	Biogasification w/CC, $2,600/kW. NG-ATR w/CC, $800/kW. Electrolysis, $1,700/kW (2020) → $420/kW (2050).
Biopower, $/kW	$3,672/kW (2020) → $3,329/kW (2050)
with CC, $/kW	Bio-IGCC (90% capture), $6,338/kW. Bio-Allam (99% capture, available from 2035), $7,144/kW.
Biopyrolysis, $/$kW_{liq.HHV}$	$2,500/kW
with CC, $/$kW_{liq.HHV}$	$4,000/kW (available from 2035)
Direct air capture, $/tpy	Direct air capture (available from 2035), $2200 per tCO_2/y installed capital cost
Resource costs in 2016$ (some later slides express values in 2018$, assuming 4% escalation from 2016)	
Oil and gas prices	AEO2019 lowest projected prices (2050: crude oil @ $56/bbl & natural gas @ $3.6 - $4.7/$GJ_{HHV}$)
Biomass feedstocks	$30 - $150 per dry tonne delivered, based largely on DOE Billion Ton Study (2016)
CO_2 transport & storage	Cost varies by location and volume stored. Bulk of supply is in the range of $35/$tCO_2$

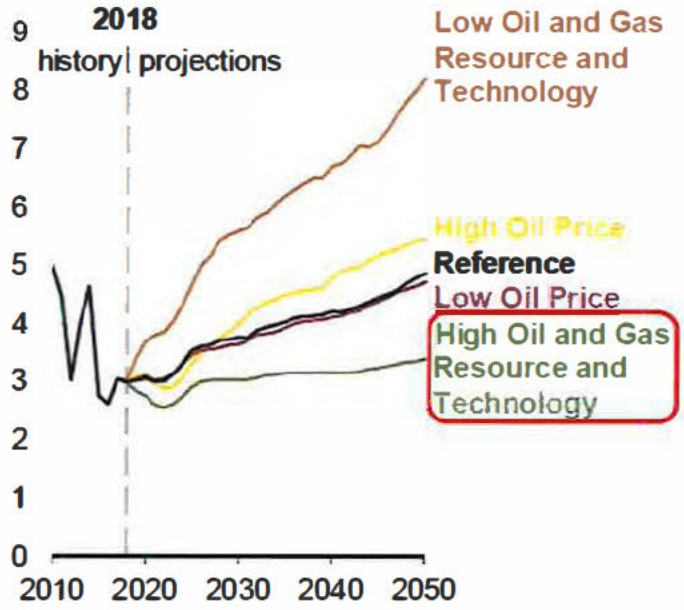
AEO 2019 low oil and natural gas price projections assumed due to flat or falling demand (as U.S. and other nations decarbonize)



North Sea Brent oil price
2018 dollars per barrel



Natural gas price at Henry Hub
2018 dollars per million British thermal unit



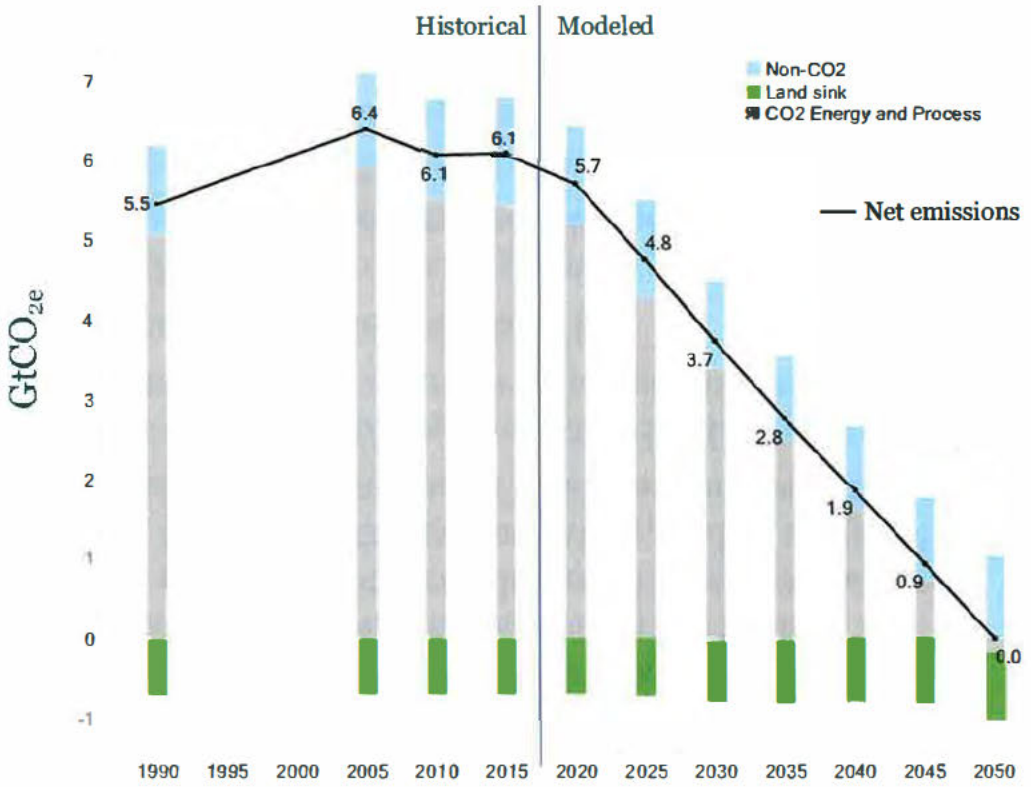
- For comparison purposes, all scenarios (including Reference) are assumed to have same oil/gas prices.
- Reduced oil/gas demand is likely to put downward pressure on prices.
- Lower prices should thus be expected in net-zero pathways vs. Reference (business as usual).
- Without a general-equilibrium model, the exact price effect is uncertain; we take a conservative approach in this study and treat oil/gas prices as the same in both Reference and net-zero pathways.
- This choice likely *understates* cost savings from reduced oil & gas use in net-zero paths.

U.S. Energy Information Administration #AEO2019 www.eia.gov/aeo

Net-zero emissions by 2050 sets decarbonization target for energy and industrial process emissions

Year	Non-CO_2*	Land sink**	Energy & Industrial system
	Gt CO_{2e}		
1990	1.1	-0.7	5.06
2005	1.19	-0.7	5.92
2010	1.24	-0.7	5.52
2015	1.35	-0.7	5.43
2020	1.22	-0.7	**5.2**
2025	1.19	-0.73	**4.3**
2030	1.09	-0.75	**3.41**
2035	1.04	-0.78	**2.51**
2040	1.05	-0.8	**1.62**
2045	1.04	-0.83	**0.72**
2050	1.02	-0.85	**-0.17**

* *United States Mid-Century Strategy for Deep Decarbonization* benchmark scenario (U.S. Whitehouse, 2016)
** Natural plus enhanced land sink.



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Carbon Mitigation Initiative

Constructing multiple decarbonization pathways



Summary of this section

We define and model five different net-zero energy-system scenarios (or pathways), each with different assumptions about energy-demand and energy-supply technology options available in the future. The pathways help highlight the role of three key elements in energy system transitions: 1) extent of end-use electrification in transport & buildings, 2) extent of solar & wind electricity generation, and 3) extent of biomass utilization for energy. Each of the 5 scenarios has its own short-hand label used in presenting results:

E+ Assumes aggressive end-use electrification, but energy-supply options for minimizing total energy-system cost while meeting the goal of net-zero emissions in 2050 are relatively unconstrained

E- Less aggressive end-use electrification, but same supply-side options as E+

E- B+ Electrification level of E-; Higher biomass supply allowed to enable possible greater biomass-based liquid fuels production to meet liquid fuel demands of non-electrified transport

E+ RE- Electrification level of E+; On supply-side, RE (wind and solar) rate of increase constrained to max historical build rate. Higher CO_2 storage allowed to enable the option of more fossil fuel use that E+

E+ RE+ Electrification level of E+; Supply-side constrained to be 100% renewable by 2050, with no new nuclear plants built, and no underground carbon storage by 2050.

A large number of sensitivity cases were run to test the impact of changing input parameter values.

Five pathways, each with distinguishing features, for a net-zero energy/industrial system by 2050



	REF ~AEO 2019	E+ high electrification	E- less-high electrification	E- B+ high biomass	E+ RE- renewable constrained	E+ RE+ 100% renewable
CO_2 emissions target		- 0.17 $GtCO_2$ in 2050				
Electrification	Low	High	Less high	Less high	High	High
Wind/solar annual build	n/a	10%/y growth limit	10%/y growth limit	10%/y growth limit	Recent GW/y limit	10%/y growth limit
Existing nuclear	50% → 80-y life	50% → 80-y life	50% → 80-y life	50% → 80-y life	50% → 80-y life	Retire @ 60 years
New nuclear	Disallow in CA	Disallow in CA	Disallow in CA	Disallow in CA	Disallow in CA	Disallowed
Fossil fuel use	Allow	Allow	Allow	Allow	Allow	None by 2050
Maximum CO_2 storage	n/a	1.8 Gt/y in 2050	1.8 Gt/y in 2050	1.8 Gt/y in 2050	3 Gt/y in 2050	Not allowed
Biomass supply limit	n/a	13 EJ/y by 2050 (0.7 Gt/y biomass) [*No new land converted to bioenergy*]		23 EJ/y by 2050 (1.3 Gt/y biomass)	13 EJ/y by 2050 (0.7 Gt/y biomass) [*No new land converted to bioenergy*]	

A large number of scenario variants have been run to test the sensitivity of results to input assumptions.



Land & non-CO2	1	E+ Land+	Higher net land sink + non-CO2 emissions (2050 CO2 emission cap for energy/industry changes from -0.17 to 0.27
	2	E+ Land-	Lower net land sink + non-CO2 emissions (2050 CO2 emission cap for energy/industry changes from -0.17 to -0.73 Gt)
Natural gas prices	3	E+ Gas+	AEO2020 'low oil and gas supply' scenario (e.g. 2050 Texas NG price changes from 3.53 to 6.56 USD/MMBtu)
	4	E+ Gas-	AEO2020 'high oil and gas supply' scenario (e.g. 2050 Texas NG price changes from 3.53 to 2.54 USD/MMBtu)
Power sector capital costs	5	E+ NGCC+	Higher NGCC-CCS capex (2050 capex changes from 1725 to 2589 $/kW)
	6	E+ NGCC-	Lower NGCC-CCS capex (2050 capex change from 1725 to 1380 $/kW)
	7	E+ Nuclear+	Higher nuclear capex (2050 capex changes from 5530 to 8295 $/kW)
	8	E+ Nuclear-	Lower nuclear capex (capex changes from 5530 to 4423 $/kW)
	9	E+ Solar_Wind+	Higher solar/wind capex (e.g. 2050 NJ onshore wind TRG1 goes from 1723 to 2280 $/kW; PV TRG1 from 869 to 1144
	10	E+ Solar_Wind-	Lower solar/wind capex (e.g. 2050 NJ onshore wind TRG1 goes from 1723 to 1433 $/kW, PV TRG1 from 869 to 453 $/kW)
	11	E+ Trans+	Higher transmission cost (e.g. 2050 Mid Atlantic<-->New York transmission cost doubles to 5642 $/kW)
Power sector capacity build rates	12	E+ TrRate-	Higher transmission capacity constraint (e.g. 2050 Mid-Atlantic<-->New York capacity limit 3830 MW instead of 19145
	13	E+ Wind-	GW wind installed capacity limits in 2050 (% of E+ capacity): onshore 50%; offshore-wind 100%, except 70% in Mid-Atlantic
	14	E+ Tr&Wind-	Constrained wind build rate + constrained transmission build rate (combination of cases 12 and 13)
	15	E+ NuRate-	Constrained nuclear capacity built rate (10GW/year maximum from 2030)
	16	E+ RE- NuRate-	Constrained nuclear capacity built rate (10GW/year maximum from 2030)
	17	E+ RE- NuRate&CCS-	Constrained nuclear capacity built rate (10GW/year maximum from 2030) & CO2 storage potential limit of 1.8 Gt/y
Flex load options	18	E+ No Electrolysis	Disallows electrolysis, one of the hourly flexible loads
	19	E+ No Electrolysis No Eboiler	Disallows electrolyis and electric boilers, the two hourly flexible load technology options
H2 production capital costs	20	E+ BioH2+	Higher capex for bioconversion to H2 with carbon capture (from 2700 to 4050 $/kW in 2050)
	21	E+ BioH2-	Lower capex for bioconversion to H2 with carbon capture (from 2700 to 2160 $/kW in 2050)
	22	E+ ATR+	Higher capex for ATR and SMR (both w/CCS) (from 814 to 1221 $/kW for ATR in 2050 and 826 to 1239 $/kW for SMR)
	23	E+ ATR-	Lower capex for ATR and SMR (both with CCS) (ATR: 814 --> 651 $/kW in 2050; SMR: 826 --> 660 $/kW)

H2 turbines	24	E+ 2035H2GT	Allow up to 100% H2-firing of GTs starting 2035.
Fuels production capital costs	25	E+ Synfuel+	Higher FTS/SNG capex (2050 SNG changes from 1155 to 1732 $/kW, FTS changes from 952 to 1428 $/kW)
	26	E+ Synfuel-	Lower FTS/SNG capex (2050 SNG changes from 1155 to 924 $/kW, FTS changes from 952 to 761 $/kW)
	27	E+ BioFT+	Higher biomass FT w/ccs capex (2050 capex changes from 3962 $/kW to 5948 $/kW)
	28	E+ BioFT-	Lower biomass FT w/ccs capex (2050 capex changes from 3962 $/kW to 3172 $/kW)
Direct air capture	29	E+ DAC-	Lower DAC capex (from $2,164 to $694 per tCO2/year, 2016$)
	30	E+ DACeff+	Higher DAC electric efficiency (1 instead of 2 MWh/tCO2)
	31	E+ DAC- eff+	Lower DAC capex and higher efficiency (combines 26 and 27)
Higher energy efficiency	32	E+ VMT-	15% lower VMT for light duty vehicles (cars/trucks) by 2050
	33	E+ Ieff+	3% per year increase in output ($) per unit energy input (instead of 1.9% per year)
	34	E+ Beff+	1% per year building heating and cooling energy reduction due to shell efficiency improvements
	35	E+ EEF+	Combination of the three above EE measures (results in 2050 final energy demand ~25% below E+ level)
No new biomass	36	E+ B-	E- but no additional lignocellulosic biomass beyond today's level
	37	E+ RE- B-	E- RE- but no additional lignocellulosic biomass beyond today's level
Higher biomass supply	38	E+ RE+ B+	E- RE+ with high biomass supply
	39	E+ RE- B+	E+ RE- with high biomass supply
	40	E- RE- B+	E- RE- with high biomass supply
Alt. CO2 emissions	41	E+ slow start	Energy/industry CO2 trajectory to 2030 follows 2005-2020 rate and then linearly to -0.17 Gt in 2050.
	42	E+ reverse S	Follows slow start emissions rate to 2030, then falls more rapidly to 2040, and then slows to reach -0.17 Gt in 2050.
Higher discounting	43	E+ 7%	Social discounting @7% instead of 2%
	44	E- B+ 7%	Social discounting @7% instead of 2%

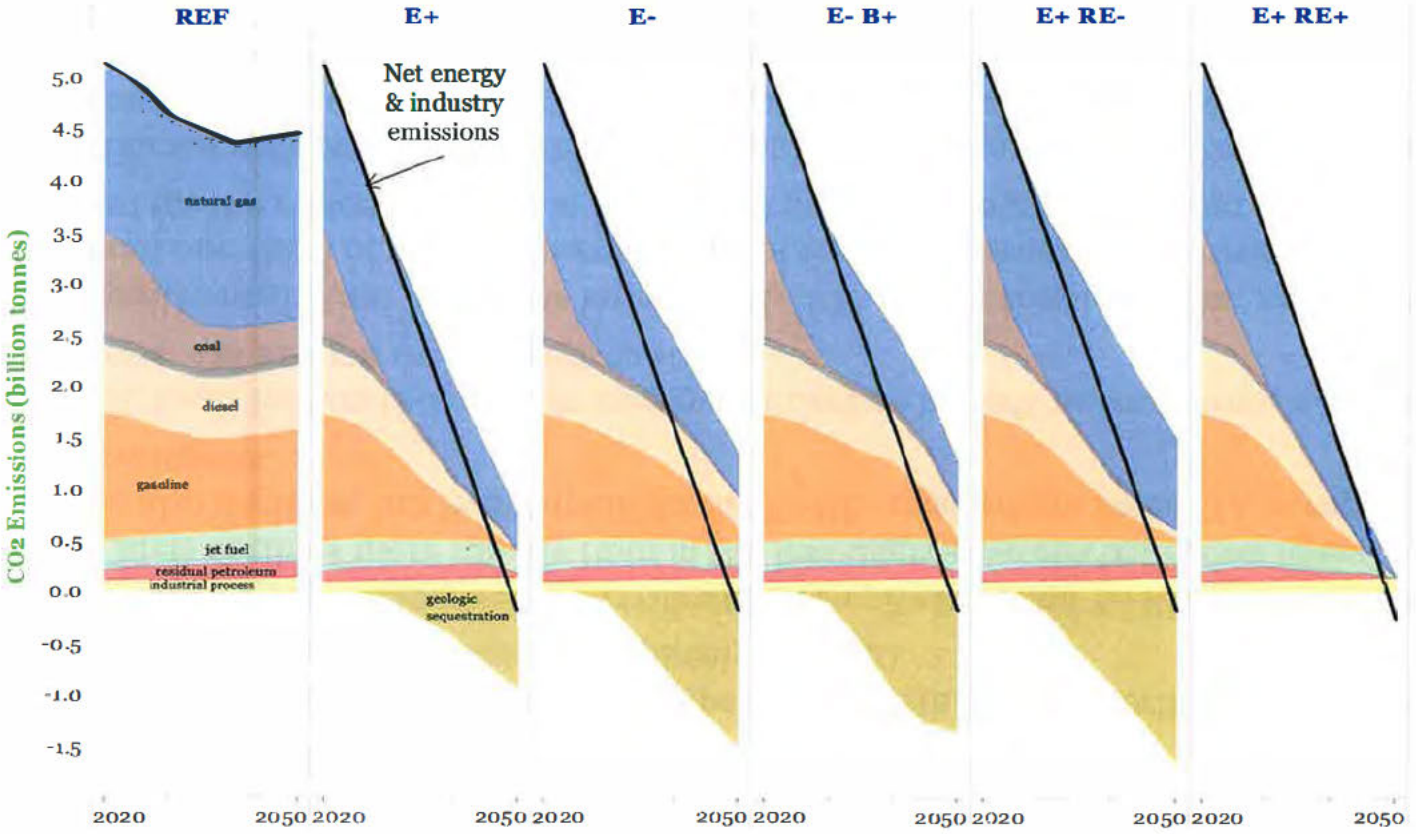
Note: Unit capital costs for fuels production technologies are given here on a per unit of output, higher heating value basis.

High-level modeling results for net-zero pathways

Summary of this section

- In all five cost-minimized energy-supply pathways, with a linear decline to net-zero emissions by 2050, coal use is essentially eliminated completely by 2030.
- In the pathways with aggressive electrification (E+, E+RE-, and E+RE+) use of petroleum-derived liquid fuels declines more rapidly than in the less-aggressive electrification cases (E-, E-B+). Natural gas use also declines, but least rapidly in the E+RE- case, where more CO_2 is captured and stored to limit emissions.
- Overall, fossil fuels in the primary energy mix decline by 62% to 100% from 2020 to 2050 across scenarios. Oil and gas decline 56% to 100%.
- The fossil contribution in 2050 is largest in E+ RE-, where fossil, nuclear, and renewables each account for about one-third of primary energy. Except for a small contribution from nuclear, renewables account for the majority (or all, in E+RE+) of primary energy in the other four scenarios.
- A significant redirection of capital investment is needed starting in the 2020s on net-zero pathways, but cumulative amortized energy spending to pay back the capital during the 2020s is less than 3% more than in the REF scenario for any of the five net-zero pathways, and annual energy spending across the full 30-year transition as a fraction of GDP is similar to historical spending levels.

Energy and industrial CO_2 emissions are net negative by 2050 to deliver net-zero emissions for the full economy



Fossil fuel use declines significantly in all net-zero pathways; coal use all but disappearing by 2030.

- natural gas
- coal
- coke
- diesel
- gasoline
- jet fuel
- LPG
- residual petroleum
- industrial co2
- geologic sequestration

Carbon storage in long-lived products is included in the modeling, but is not shown explicitly here.

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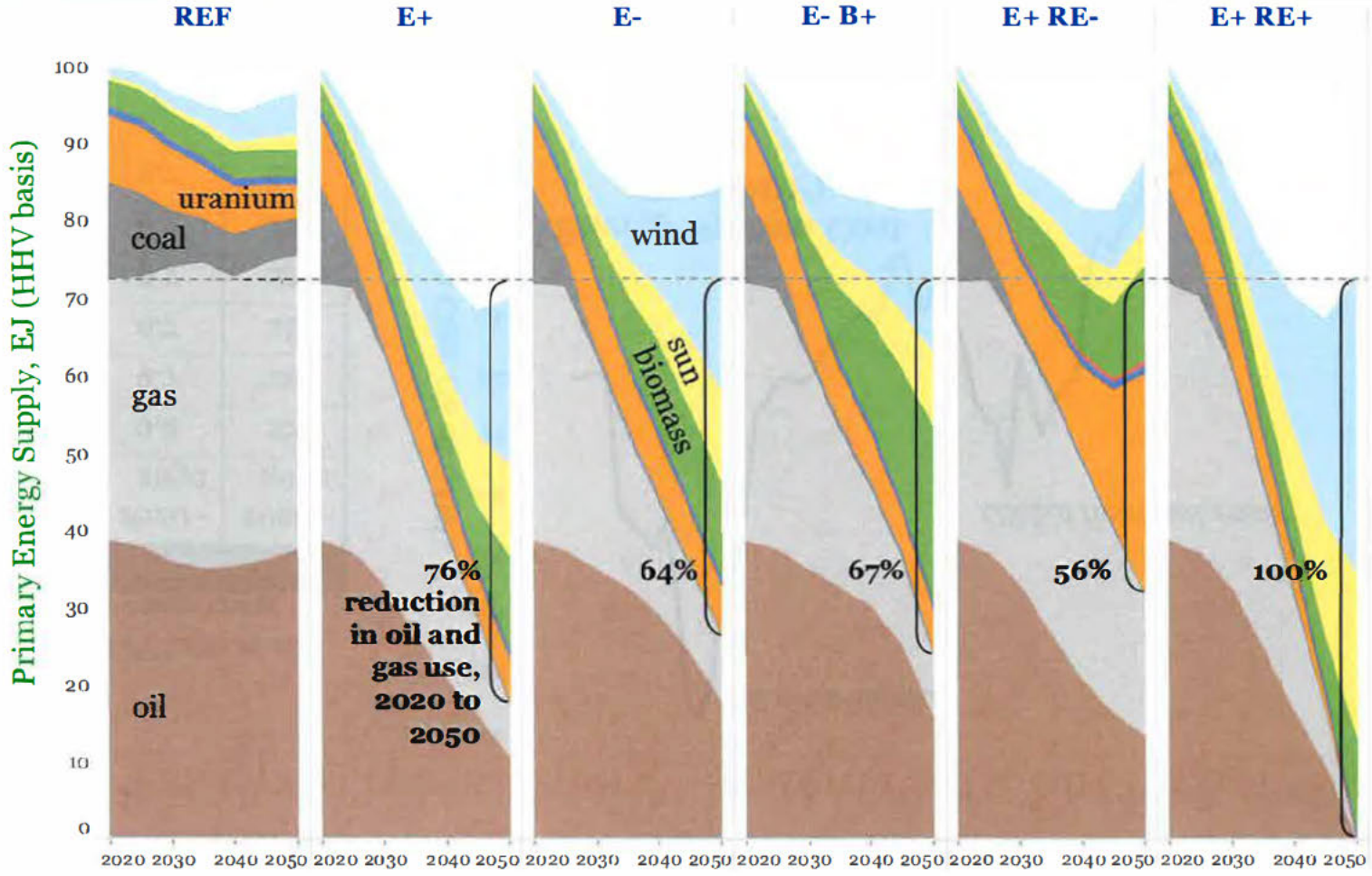
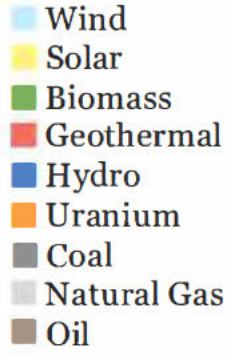
Primary energy mix in 2050 is ≤38% fossil in net-zero pathways. Coal use all but disappears by 2030. Oil & gas down 56-100%





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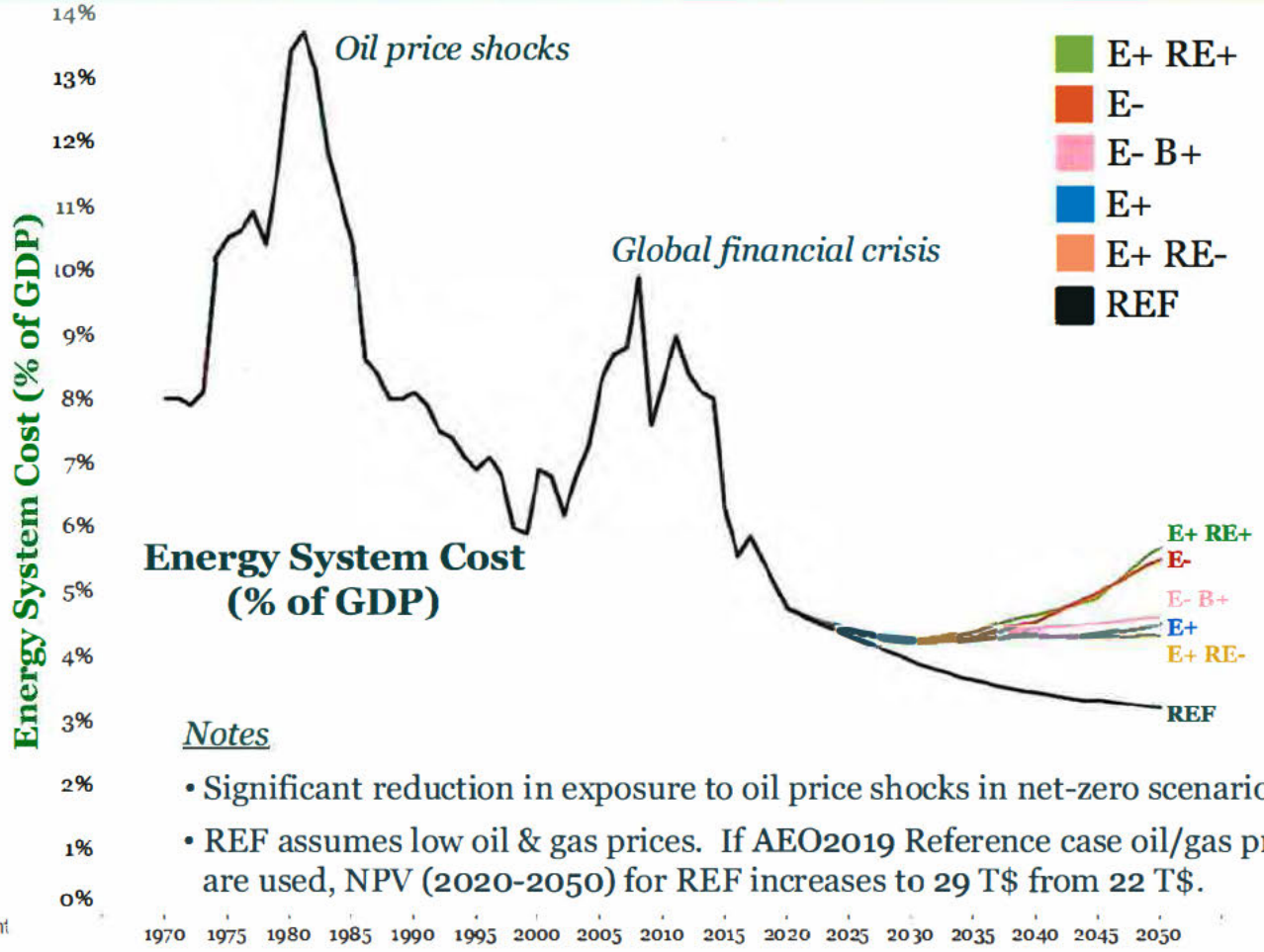
Modeled annual energy-system costs as % of GDP are comparable to (or less than) recent energy-system costs, but higher than REF

Societal NPV (2%) of all energy system costs

	Trillion 2018 $	
	2020 - 2030	2020 - 2050
REF	9.4	22
E+	9.7	26
E-	9.7	28
E- B+	9.7	27
E+ RE-	9.7	26
E+ RE+	9.7	28



Notes

- Significant reduction in exposure to oil price shocks in net-zero scenarios.
- REF assumes low oil & gas prices. If AEO2019 Reference case oil/gas prices are used, NPV (2020-2050) for REF increases to 29 T$ from 22 T$.

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Pillar 1: Improve end-use energy productivity – efficiency and electrification

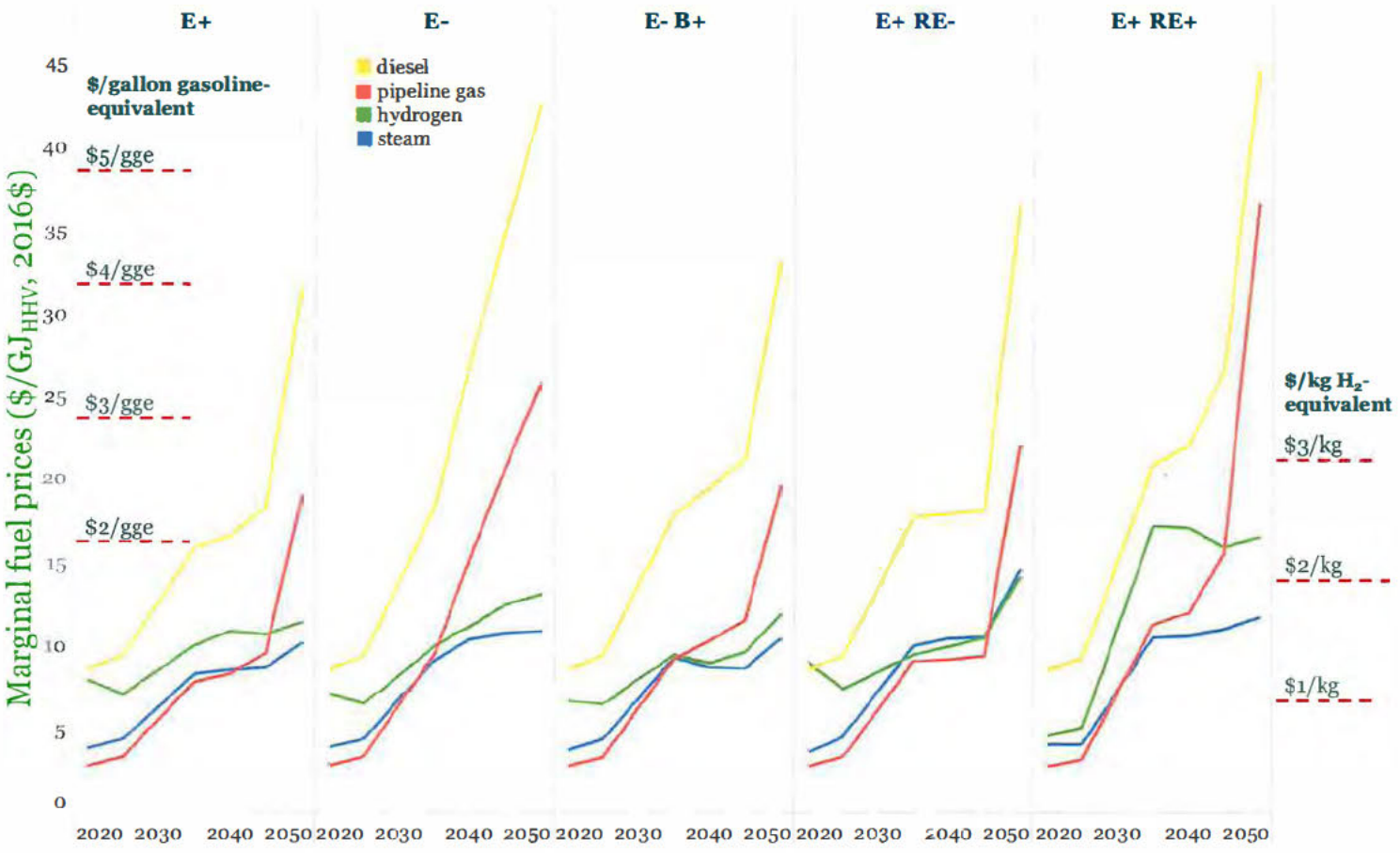


Summary of this section

- End-use efficiency improvements and electrification across all sectors are critical for reducing:
  - the required build out of the energy-supply system to deliver the energy needed to meet the given level of energy service demands.
  - the demand for liquid or gaseous fuels, which are generally more difficult/costly to decarbonize than electricity, as suggested by the significantly increasing marginal prices for fuels across the different scenarios.
- Electrification itself provides large reductions in final energy needed for transportation and heating buildings because electric drive trains for vehicles and electric heat pumps for heating are intrinsically more efficient than using fuels for these purposes.
- While there is significant electrification of transport and buildings, equipment replacements in our modeling are assumed to occur only at economic end-of-life, which reduces asset replacement costs. More aggressive replacement rates are possible, but would leave some assets stranded and increase transition costs.
- Summaries of the evolution of transportation, residential, commercial, and industrial sector final energy demands are provided in later slides in this section.

Increasing marginal prices for fuels in net-zero pathways imply growing motivation for users to improve efficiencies and electrify

- Marginal prices reflect the modeled cost of supplying one more increment of fuel.
- Values for 2020 are fossil fuel prices projected for 2020 in AEO2019.
- In later years, values reflect the cost of producing one more unit of zero-carbon fuel; for fossil fuels, values reflect the cost of both supplying one unit of fuel and negative emissions to offset carbon from burning a unit of fossil fuel.



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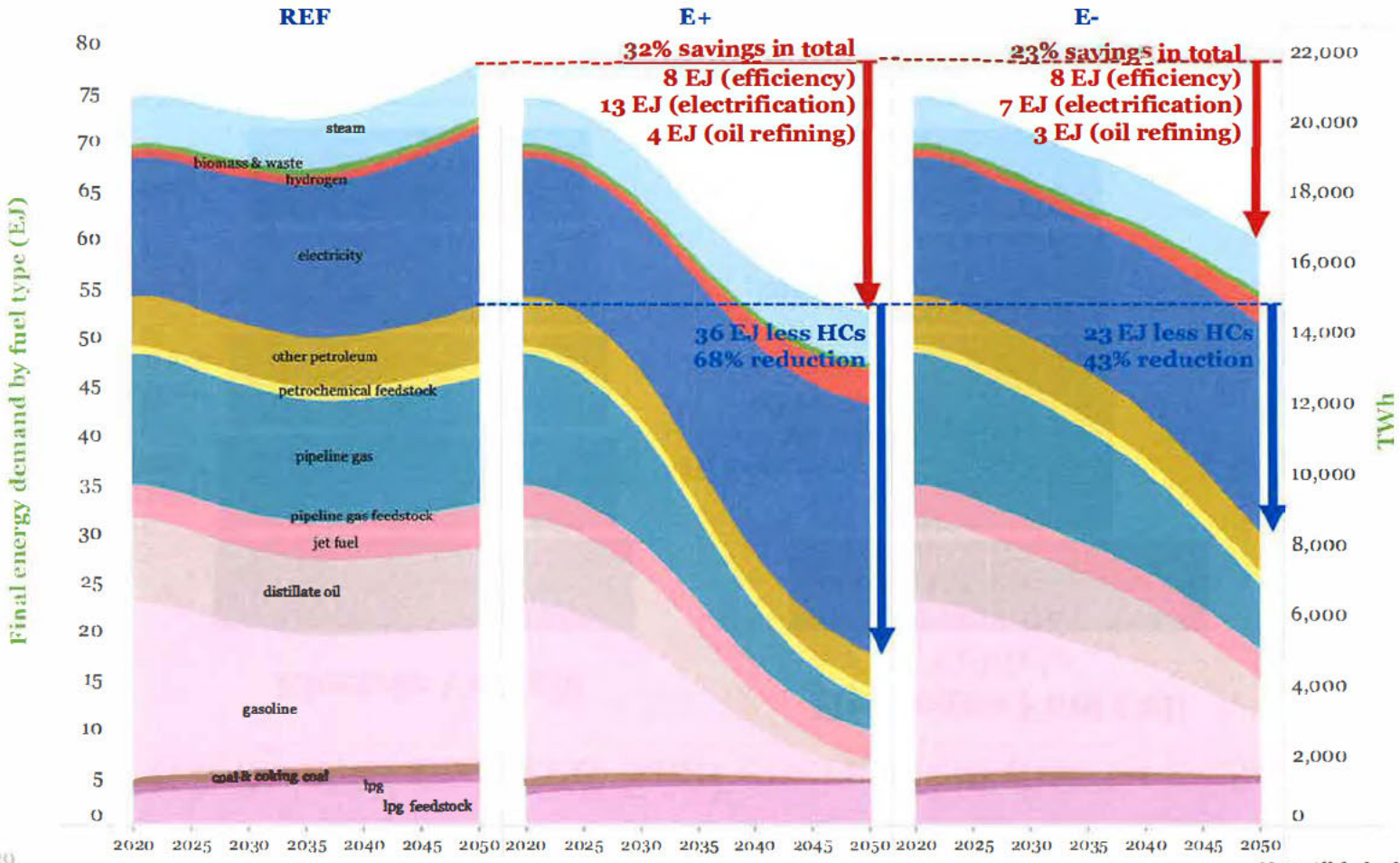
End-use energy productivity improves via same-fuel efficiency gains and via electrification; energy used for oil refining declines.





U.S. final-energy intensity (MJ/$GDP) falls, 2020 to 2050:

- 1.7%/y in REF
- 3.0 %/y in E+
- 2.6 %/y in E-

Efficiency gains in

- Most of industry
- Buildings non-heating
- Aviation

Electrification reduces fuel use and provides efficiency gains in

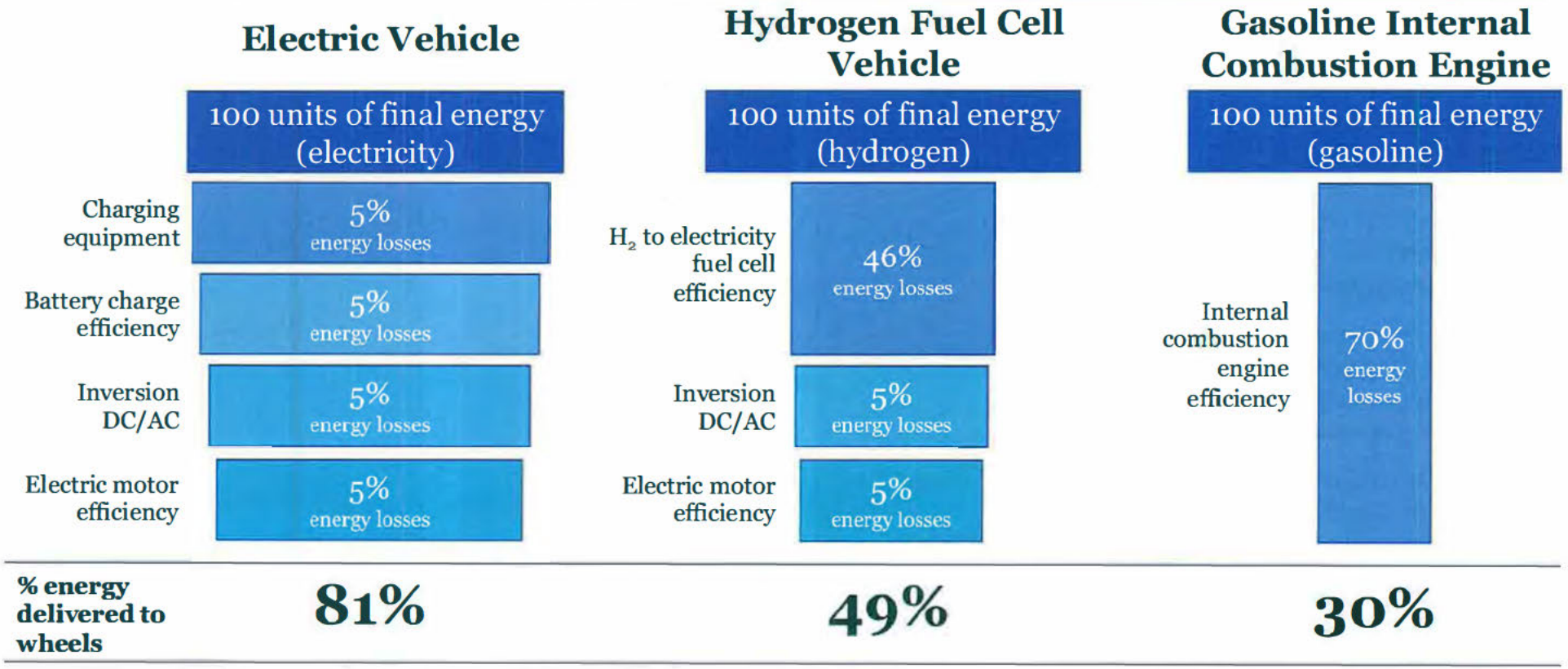
- Road transport
- Heating of buildings
- Some industry, especially iron and steel.

Oil refining energy use falls from 5.4 EJ in 2020 to 0 to 2.3 EJ in 2050 in net-zero scenarios.

Note: All fuel values reported in this slide pack are on HHV basis.

EVs and heat pumps deliver double benefit: fuel switching to clean electricity *and* reduced final energy use due to greater efficiencies





% energy delivered to wheels	81%	49%	30%

Adapted from original in Transport and Environment, "Electrofuels? Yes, we can ... if we're efficient." December 2020.

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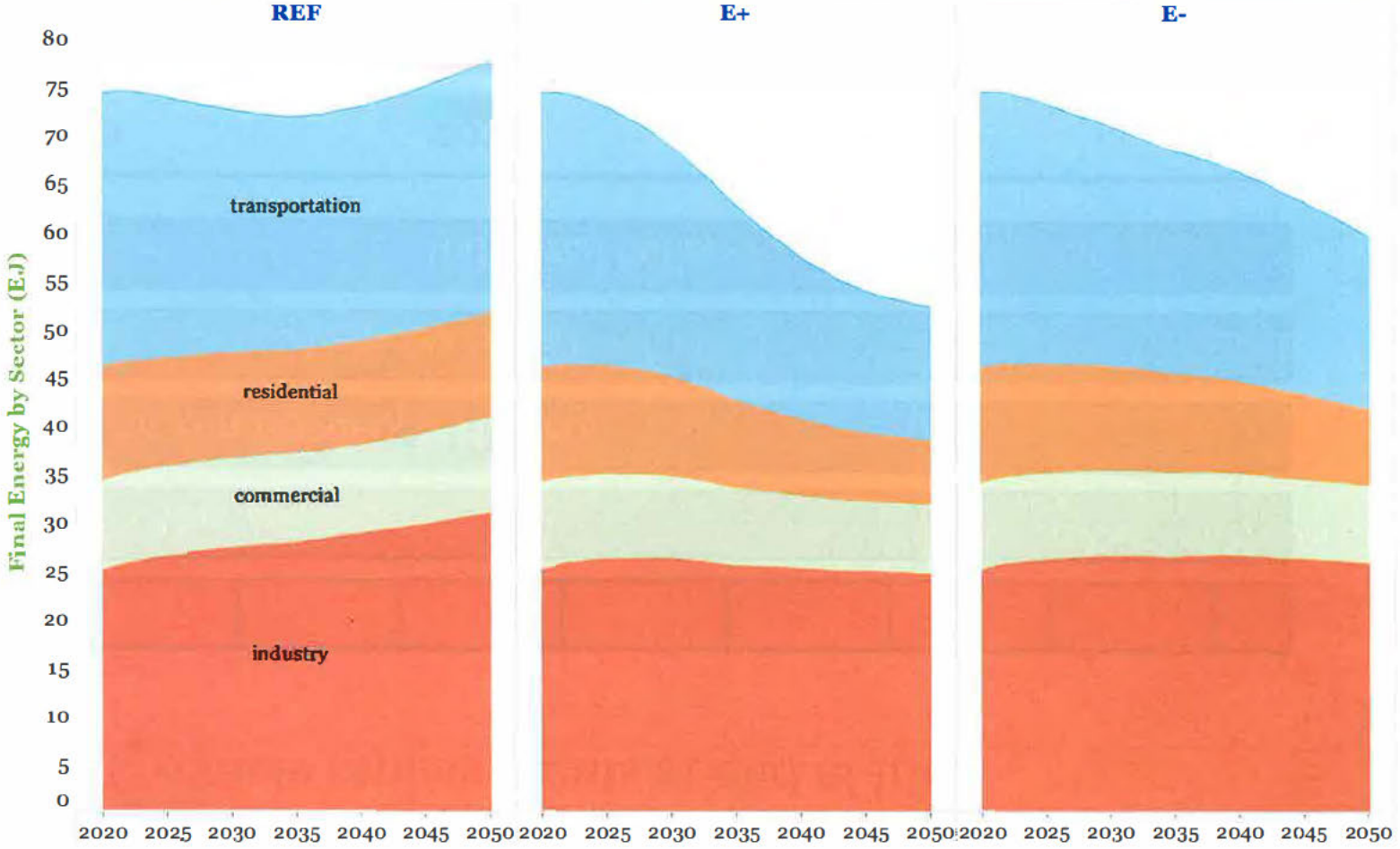
Carbon Mitigation Initiative

Final-energy demands for transportation decrease dramatically. Other sectors see more modest reductions by 2050.



Note: All fuel values reported in this slide pack are on HHV basis.

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Efficiency improvements at least cost capitalize on timing equipment/vehicle replacements at end of life.

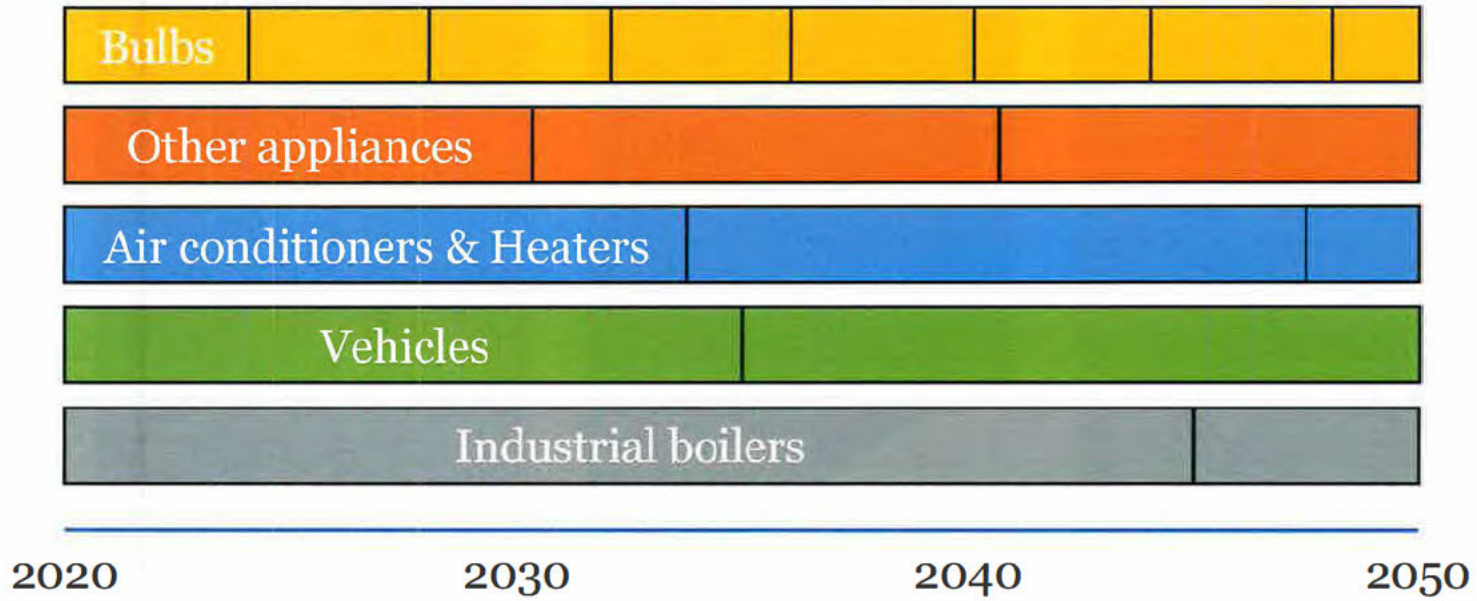


Image credit: Ryan Jones, Evolved Energy Research

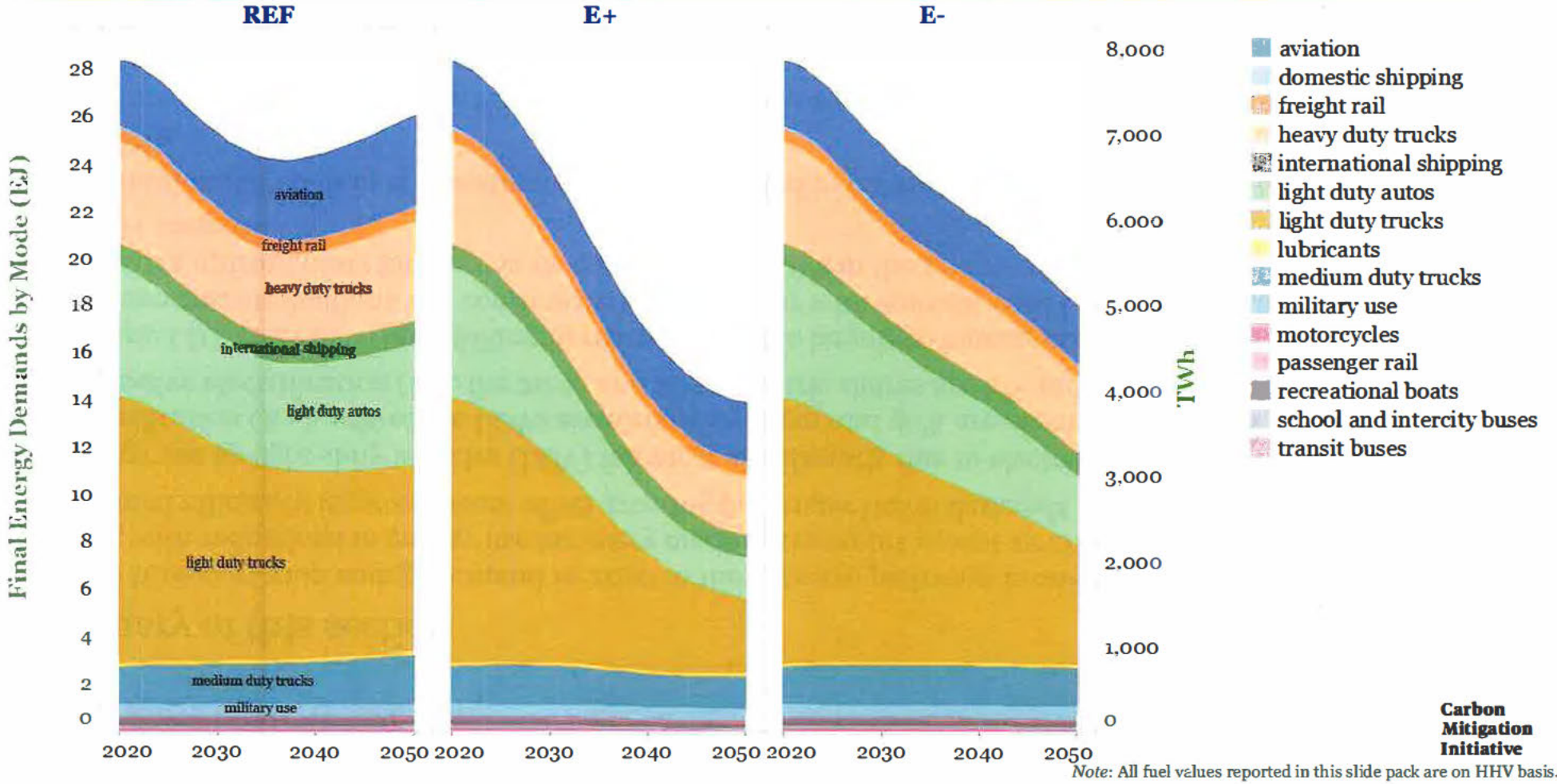
Transportation sector



Summary of this section

- Final transportation energy demand in 2050 in the net-zero pathways is one-third to one-half the 2020 level, with reductions in energy use for every mode of transport except aviation, for which 1.5%/y assumed efficiency improvements offset growing passenger travel demands
- Energy use by light-duty vehicles (LDV) fall most significantly due to electrification. With aggressive electrification (E+), 17% of the LDVs are electric by 2030 and 96% are electric by 2050. With less aggressive electrification (E-), the 2030 and 2050 electric shares are 6% and 61%.
- Electric LDV costs have been falling in recent years due largely to battery cost reductions, and the model assumes costs reductions will continue, with cost parity with conventional LDVs reached around 2030. The extra upfront costs for electric vs. conventional LDVs in the 2020s cumulatively is $185 billion in the E+ scenario.
- An additional $7 billion of investment would be needed in public charging infrastructure to support the EV fleet.
- Medium and heavy-duty truck fleets transition by 2050 to almost entirely electric or hydrogen fuel-cell power. Cost premiums for these vehicles slowly decline over time, but remain relatively high still in the 2030s compared with electric LDV premiums.

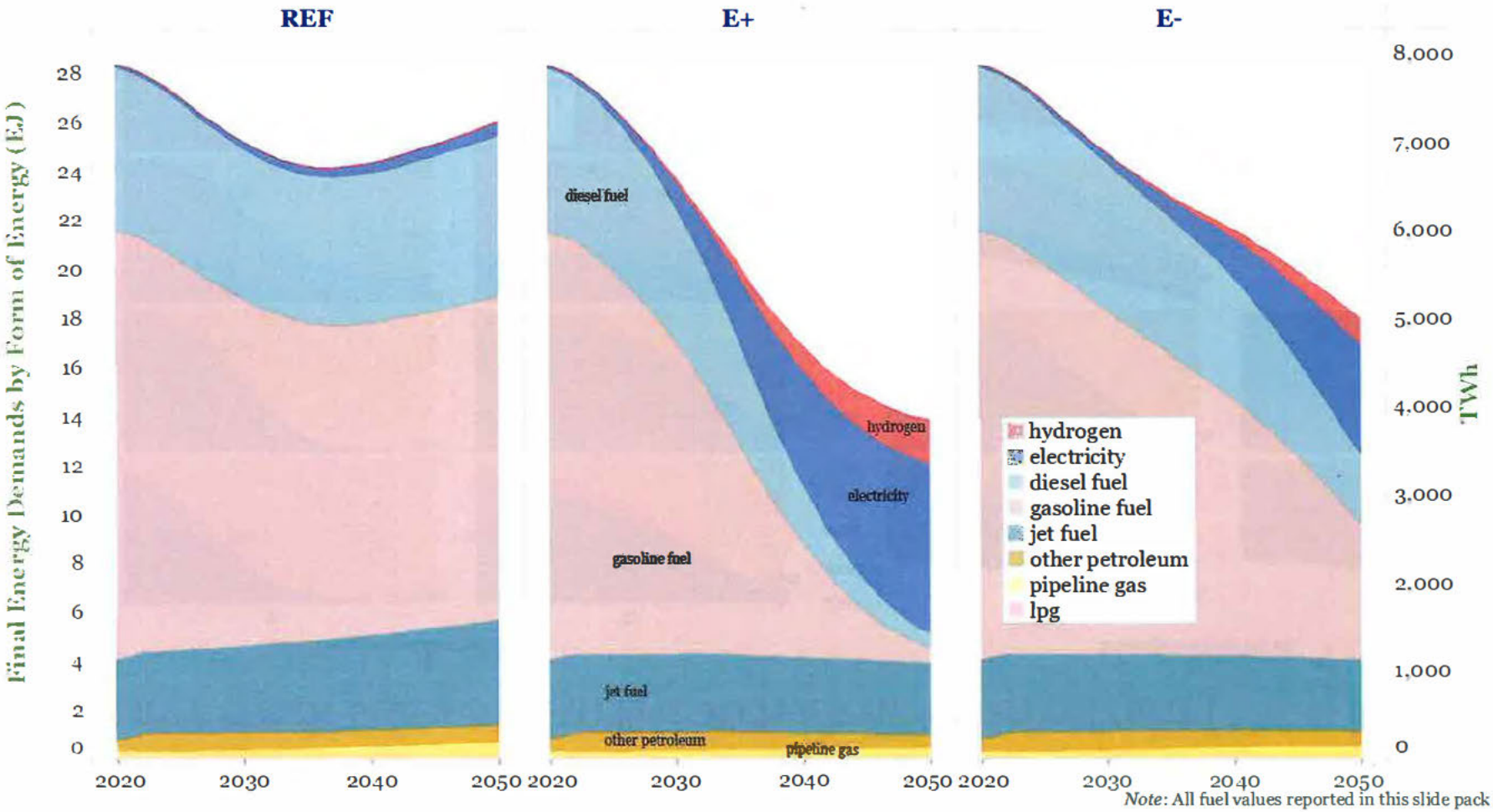
Energy use in all transportation modes falls as a result of efficiency gains (e.g., aviation) and/or electrification (e.g., cars and trucks)



Carbon Mitigation Initiative

Note: All fuel values reported in this slide pack are on HHV basis.

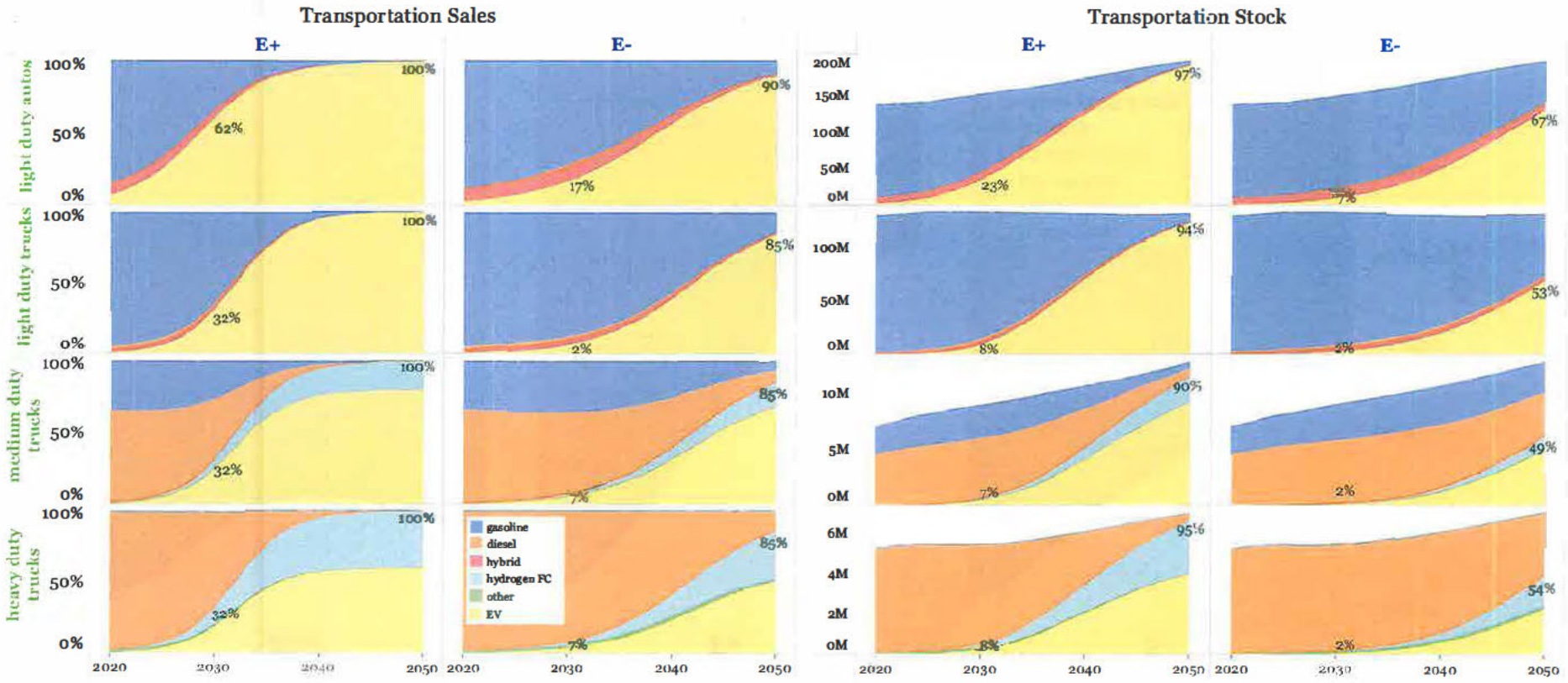
Electricity, jet fuel, and H_2 are predominant transportation fuels in E+ by 2050. Liquid fuels in 2050 are still significant in E-.



Carbon Mitigation Initiative

Note: All fuel values reported in this slide pack are on HHV basis.

In the 2040s, light duty vehicles sales are 60%-100% EV. Medium & heavy truck sales are 50%-100% electric drivetrain (EV + H_2FCV)



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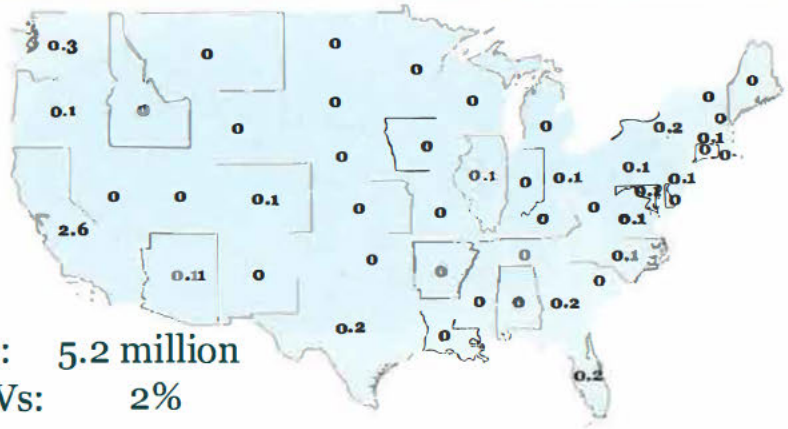
Carbon Mitigation Initiative

In E+, the stock of EVs grows to 17% of all light-duty vehicles by 2030 and 96% by 2050.



2020



# of EVs: 5.2 million
% of LDVs: 2%

2030



49 million
17%

2040



204 million
64%



2050



328 million
96%

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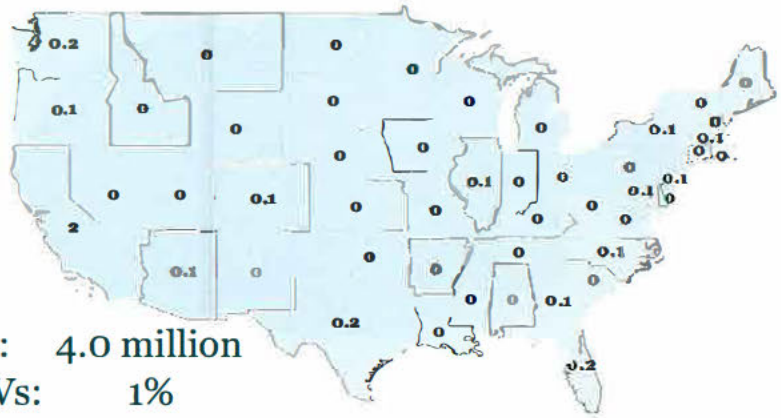
In E-, the stock of EVs grows to 6% of all light-duty vehicles by 2030 and 61% by 2050.

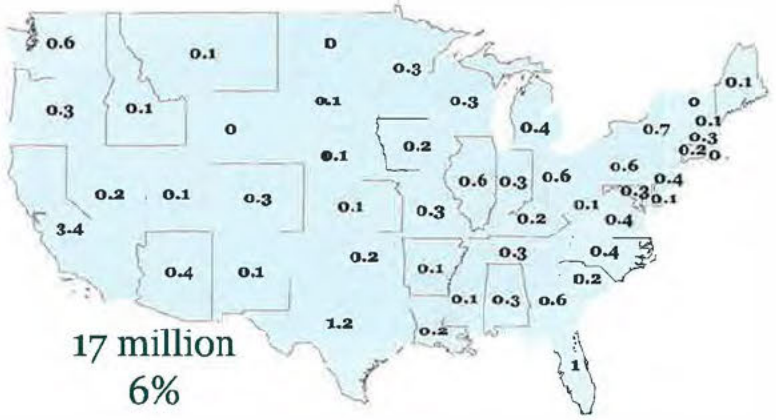


2020



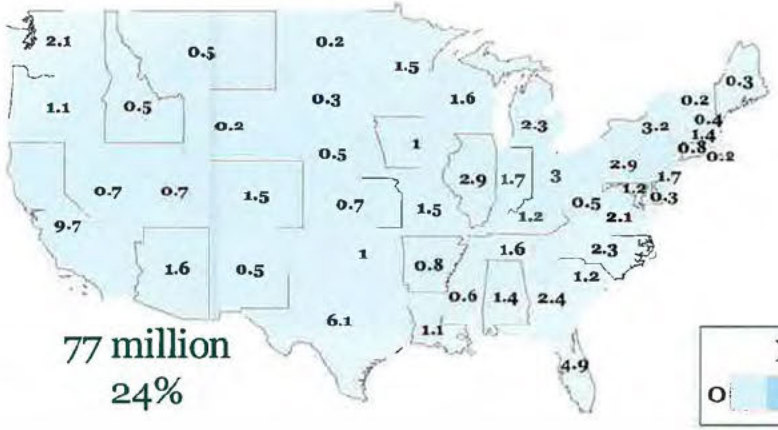
# of EVs: 4.0 million
% of LDVs: 1%

2030



17 million
6%

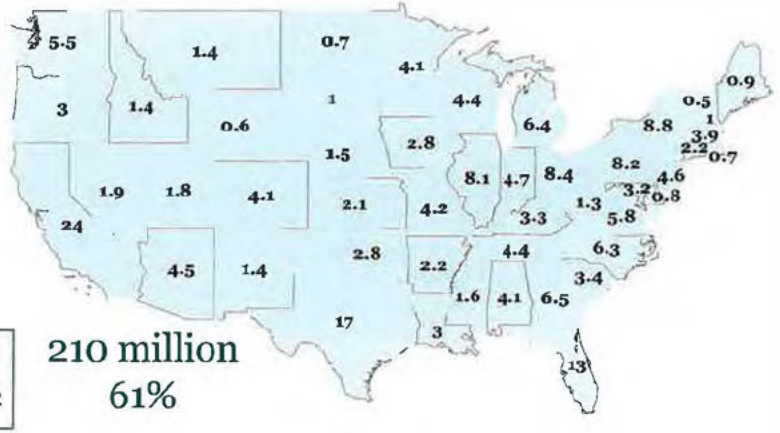
2040



77 million
24%



2050



210 million
61%

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A few states have announced targets for EV registrations in 2025 and/or 2030 that approach E+ levels and generally exceed E- levels.

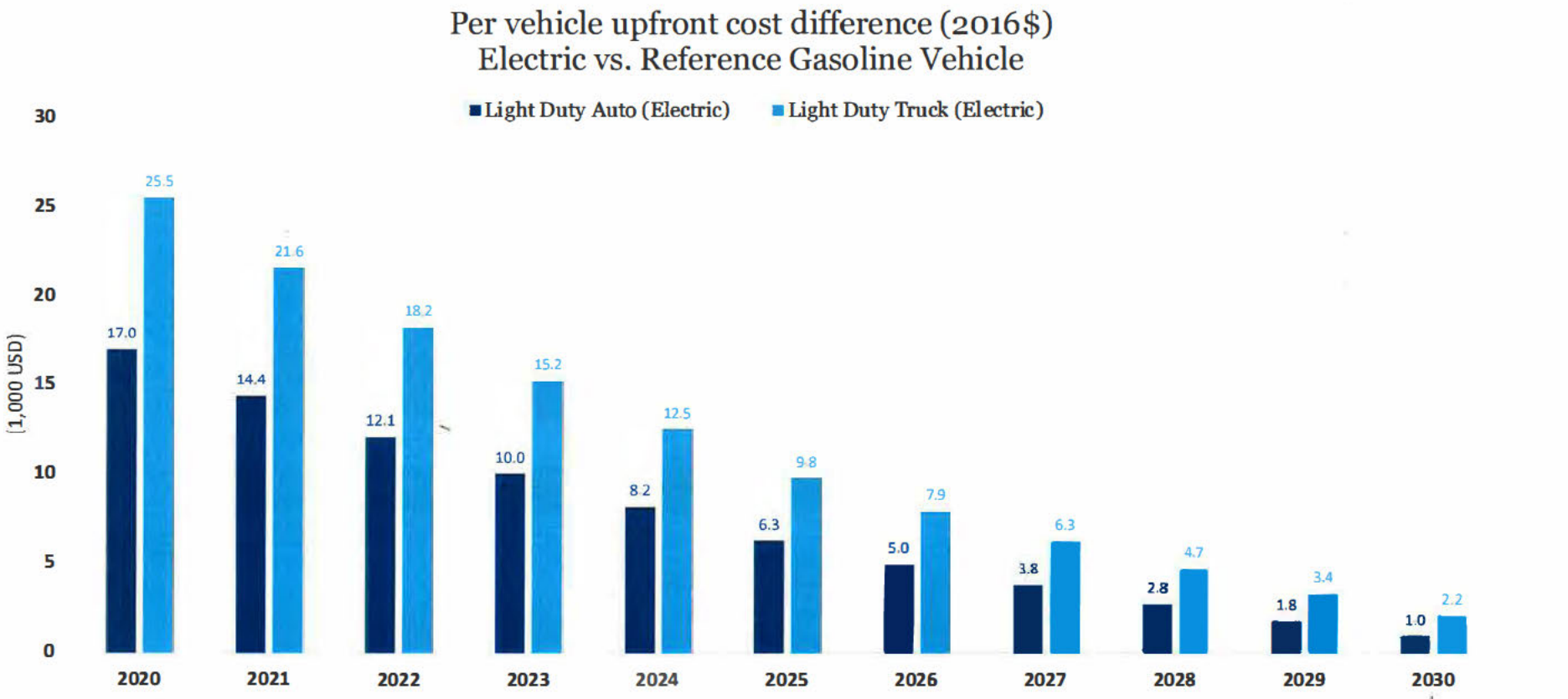


Green states have announced targets that exceed E- levels.

	State targets	E+	E-
	Battery-EVs in the light-duty vehicle fleet (millions)		
California, 2025	1.5	4.9	2.7
California, 2030	5.0	7.3	3.4
Colorado, 2025	0.055	0.542	0.212
Colorado, 2030	0.94	0.97	0.34
Connecticut, 2025	0.15	0.27	0.10
Maine, 2025	0.007	0.10	0.032
Maryland, 2025	0.3	0.41	0.15
Massachusetts, 2025	0.3	0.49	0.18
New Jersey, 2025	0.33	0.59	0.22
New York, 2025	0.85	1.09	0.39
New York, 2030	2	2.02	0.67
North Carolina, 2025	0.08	0.73	0.25
Rhode Island, 2025	0.043	0.077	0.025
Vermont, 2025	0.06	0.06	0.023

Upfront cost premiums between electric and gasoline light duty vehicles fall through 2020s, reaching close to parity by 2030





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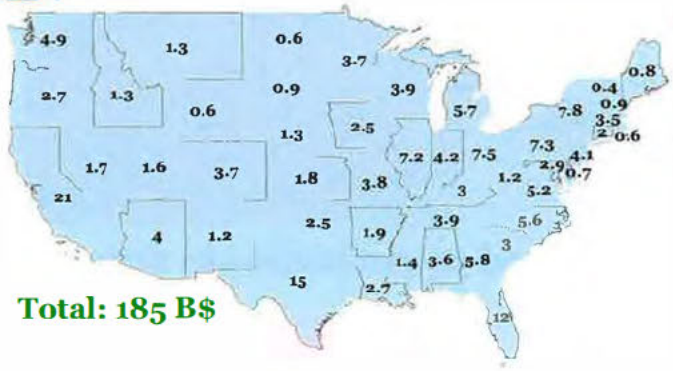
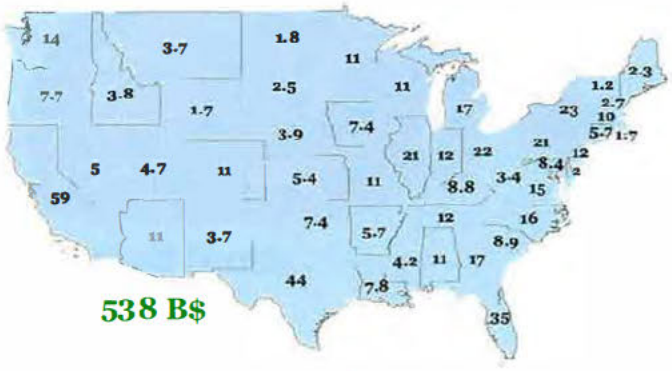
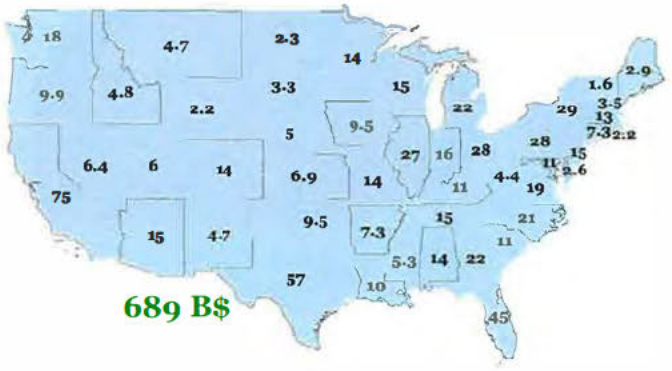
Incremental first costs for light-duty vehicles (E+ vs. REF) is $185B in the 2020s; for E- vs. REF, the increment is $9B.

Added capital for light-duty vehicle purchases: net-zero pathway vs. REF (billion $)

E+



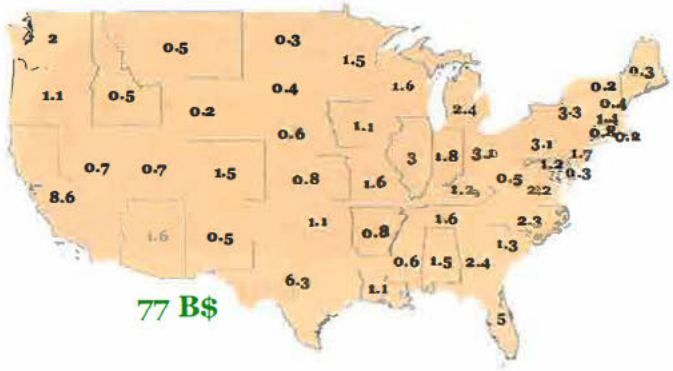


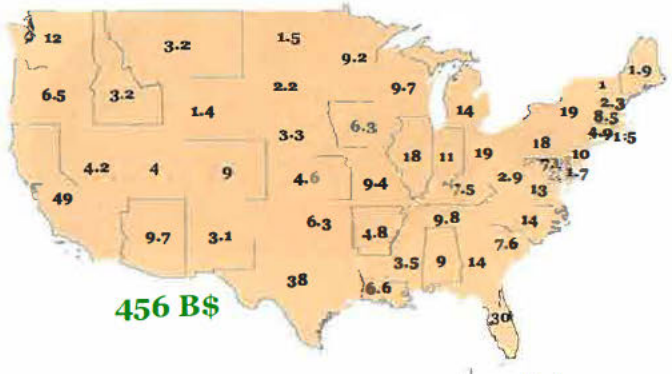


2020s 2030s 2040s

E-







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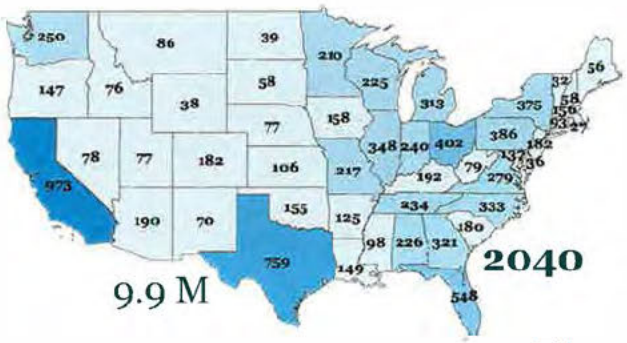
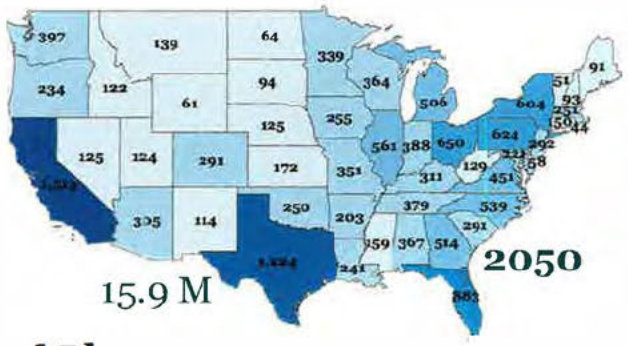
The number of public charging plugs needed to support EV fleets are still modest in 2030 in most states, but grow rapidly after.

Number of public EV charging plugs in operation



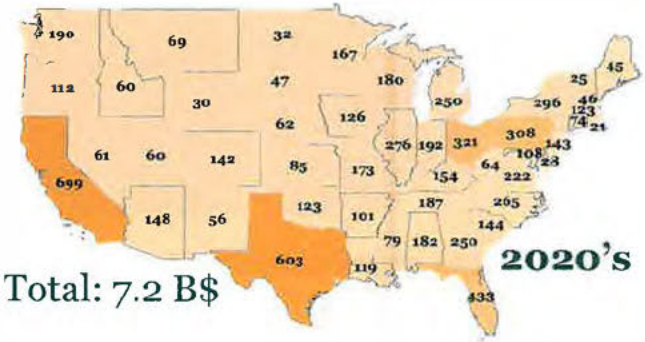


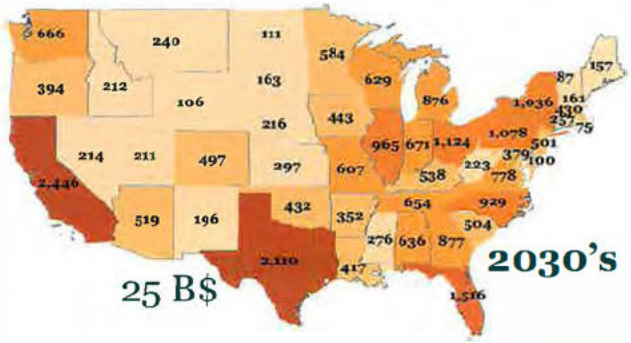


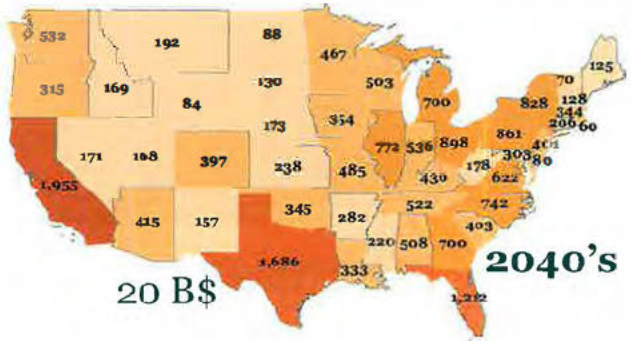
Thousand Plugs

0 — 1,600

Decadal investments in public EV charging plugs







Million 2018 $

0 — 2,400

E+ scenario

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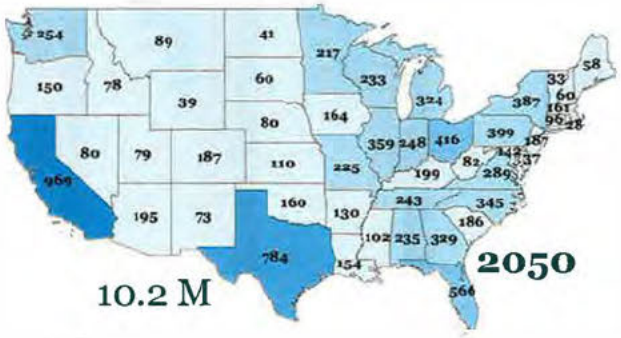
The number of public charging plugs needed to support EV fleets are still modest in 2030 in most states, but grow rapidly after.

Number of public EV charging plugs in operation





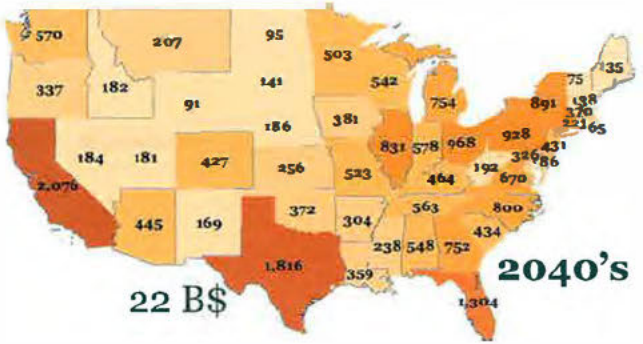


Thousand Plugs
0 — 1,600

Decadal investments in public EV charging plugs







Million 2018 $
0 — 2,400

E- scenario

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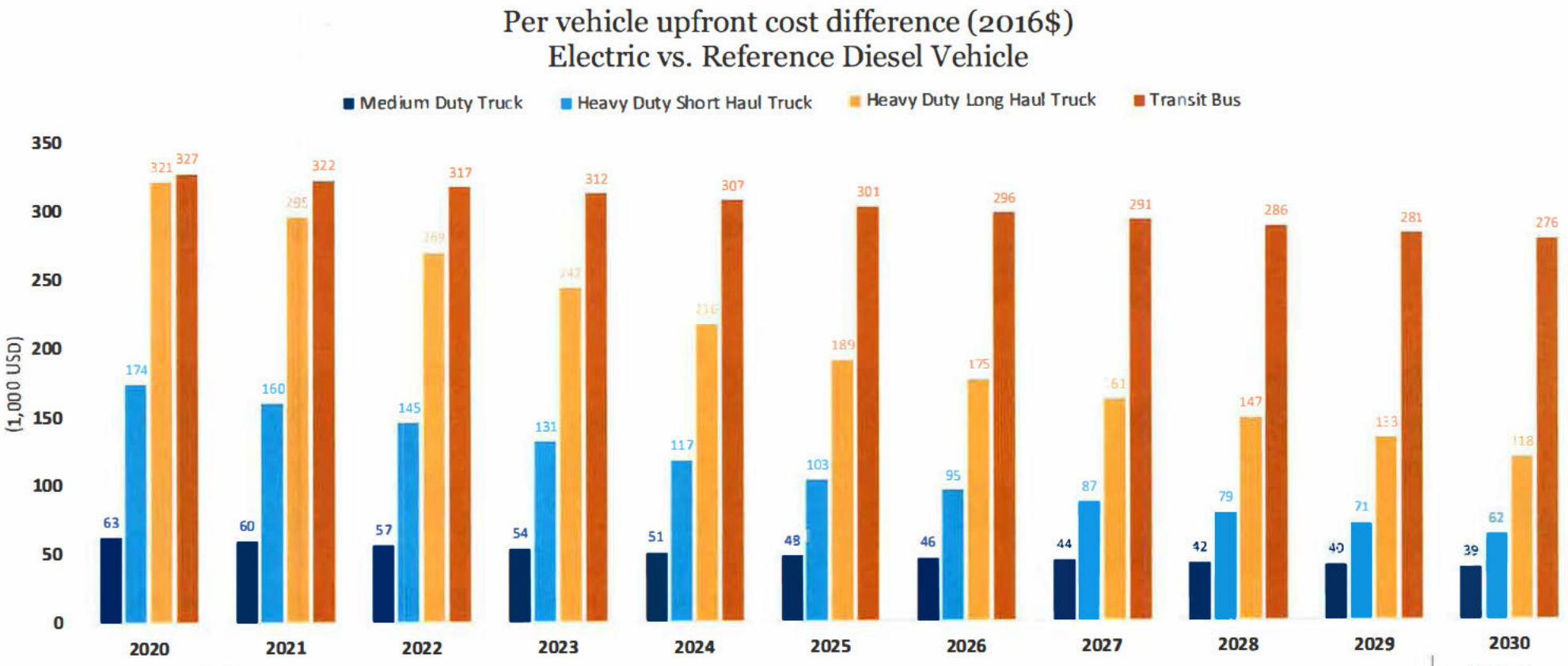
Upfront cost premium for medium and heavy duty electric trucks and transit buses remains significant





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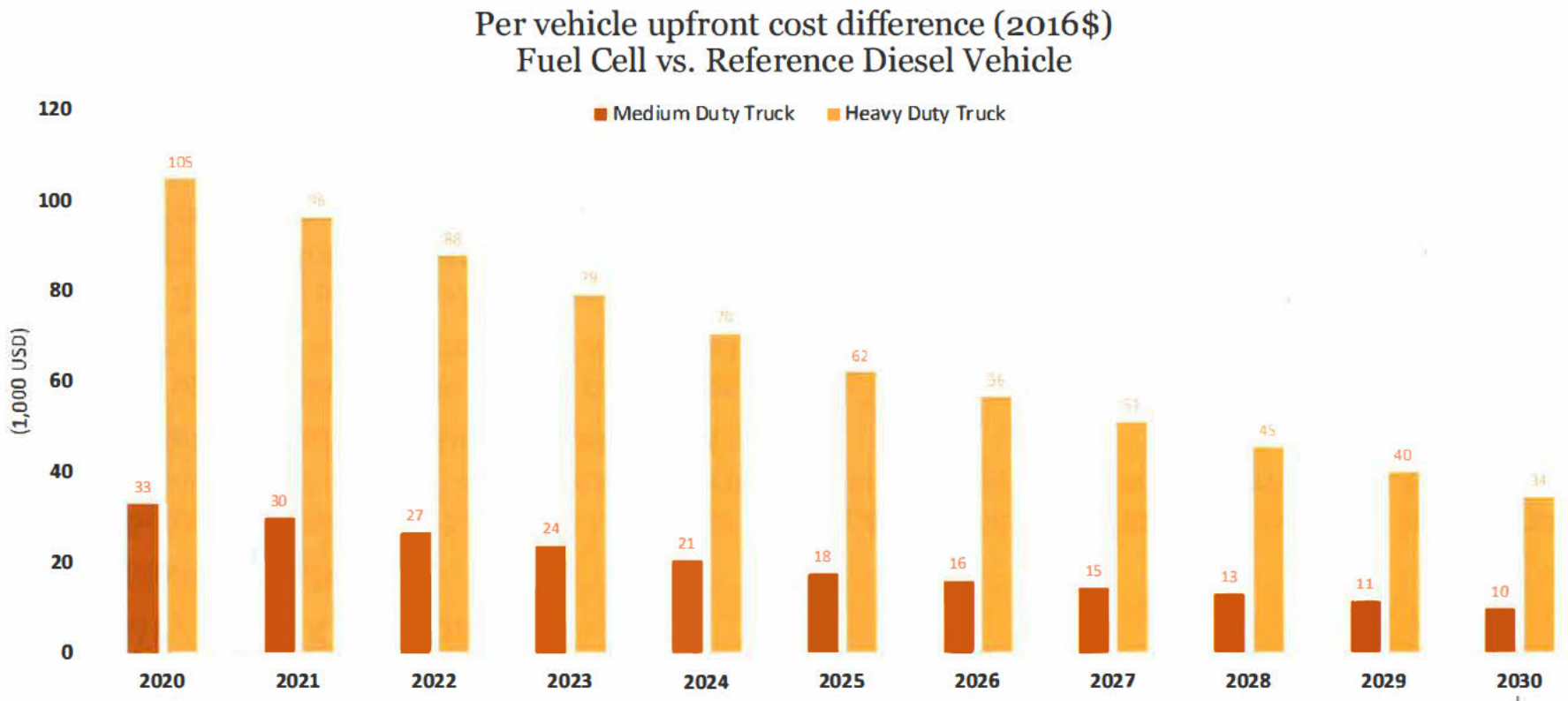
Medium and heavy duty fuel cell vehicles have much lower upfront cost premium than electric but higher fueling costs





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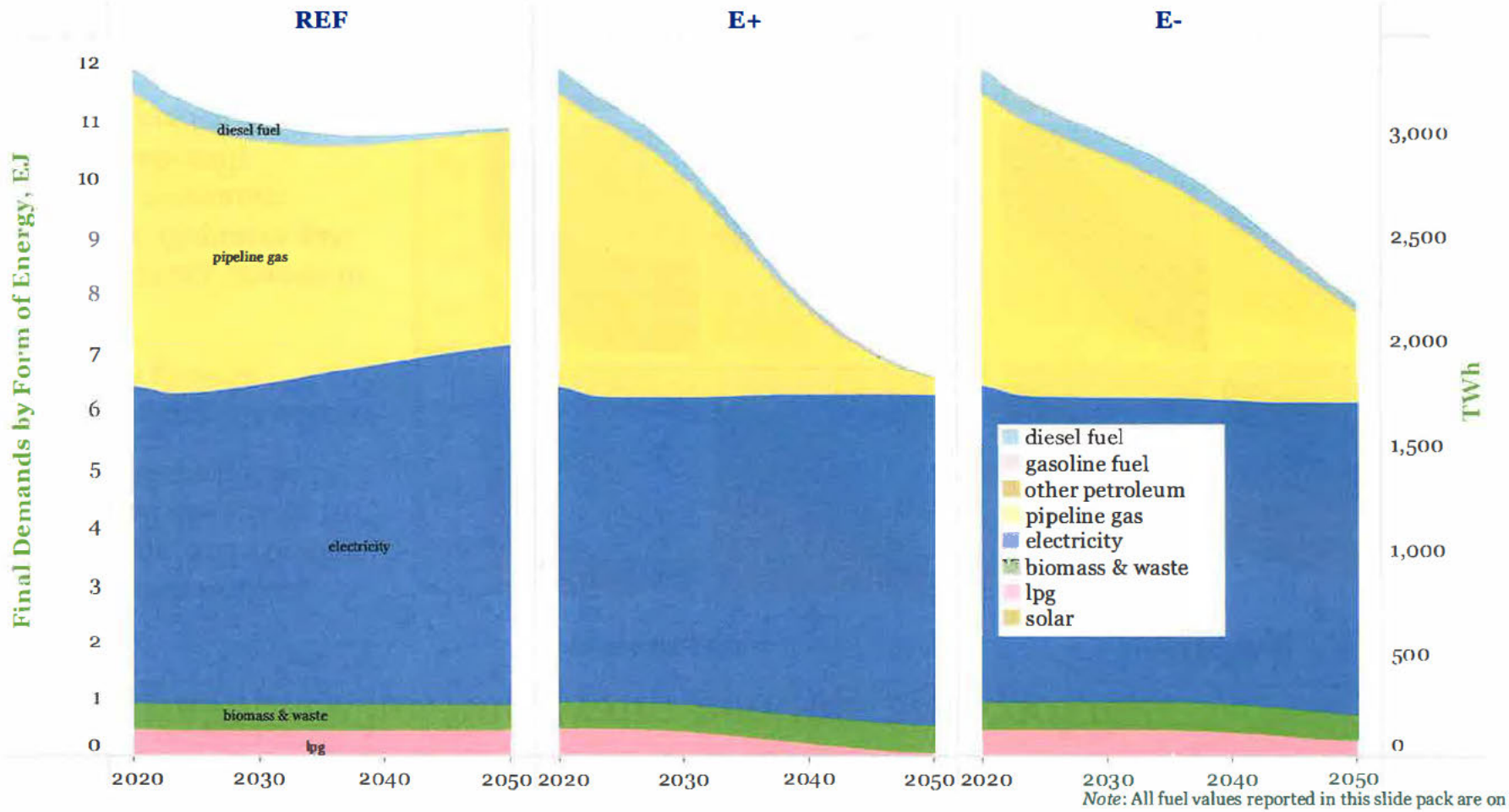
Buildings sector



Summary of this section

- In residential buildings:
  - The use of natural gas for space and water heating and cooking is nearly fully replaced by electricity by 2050 across the net-zero transitions, and final energy use is dramatically lower as a result of heating (and air conditioning) using heat pumps.
  - The market penetration of heat pumps for heating/cooling is highest in warmer climate regions. They are also adopted in colder regions, although they operate somewhat less efficiently.
  - The first-cost premium for space and water heating in the net-zero pathways is $60 to $70 billion in aggregate for the country in the 2020s compared with REF, or 12% to 13% more. The increase is modest because heat pumps heat and cool using the same device, unlike gas-fired heaters.
- Commercial sector final energy use also declines, but not as significantly as for the residential sector:
  - Electricity replaces natural gas in space conditioning, with growing contributions from heat pumps, but also growth in electric resistance heat for which efficiency gains are not as significant as for heat pumps. Electric cooking also grows.
  - The first-cost premium for space and water heating and ventilation in the net-zero pathways is about $110 billion in aggregate for the country from 2021-2030 compared with REF, an increase of about 5%.

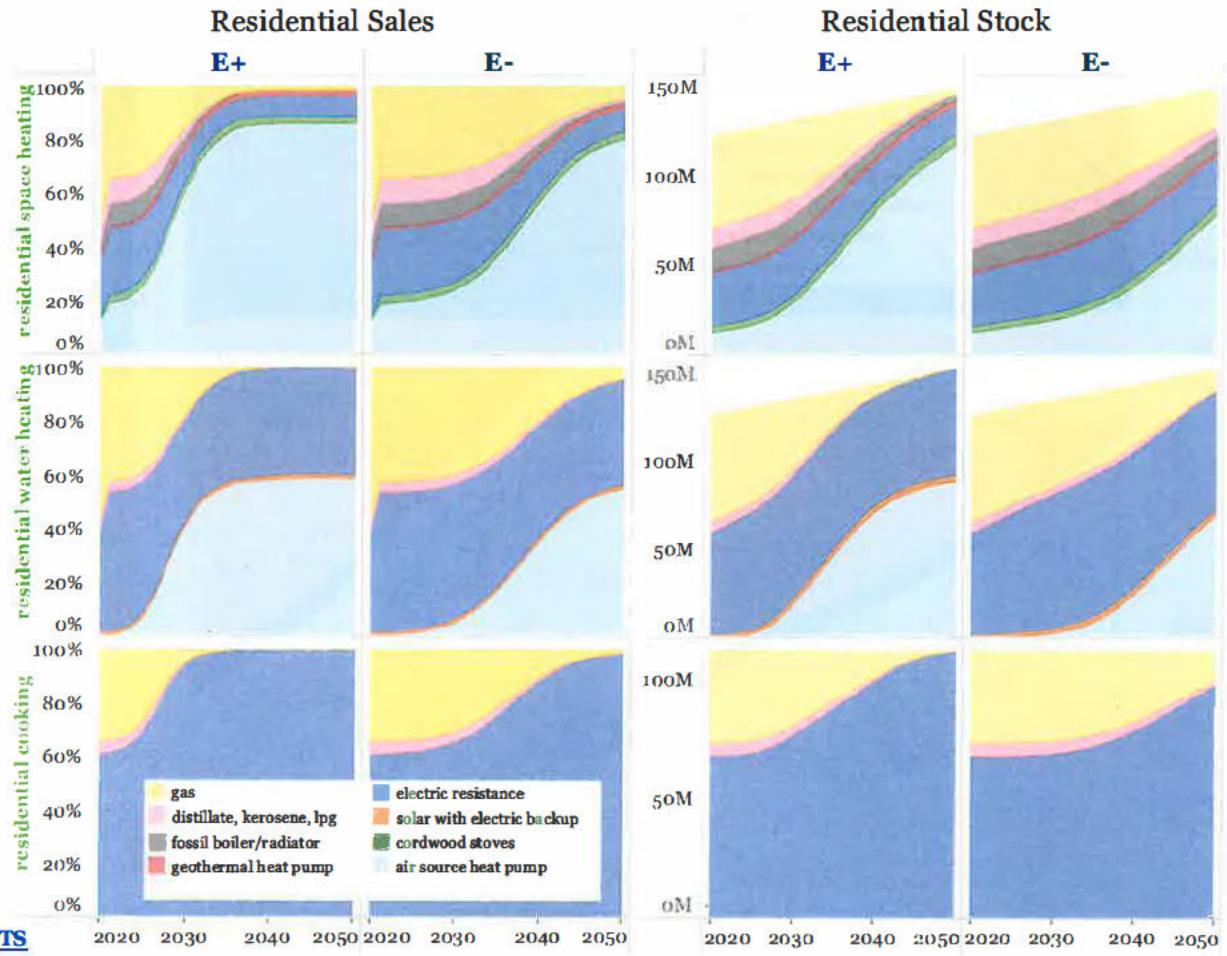
Residential sector final energy use declines, and by 2050 electricity accounts for 85% in E+ and 70% in E-.



Note: All fuel values reported in this slide pack are on HHV basis.

Consumer investment choices shift rapidly to electricity for residential space heating, water heating, and cooking.

- By 2050, space heating, water heating, and cooking are nearly all electric in E+ and 80-90% electric in E-
- In space heating, air-source heat pumps grow to dominate.
- In water heating, growth in heat pumps displaces gas-fired units; resistance heating is generally retained in colder climates.
- Induction cook stoves are 100% of new sales by 2035 in E+ and 2050 in E-.



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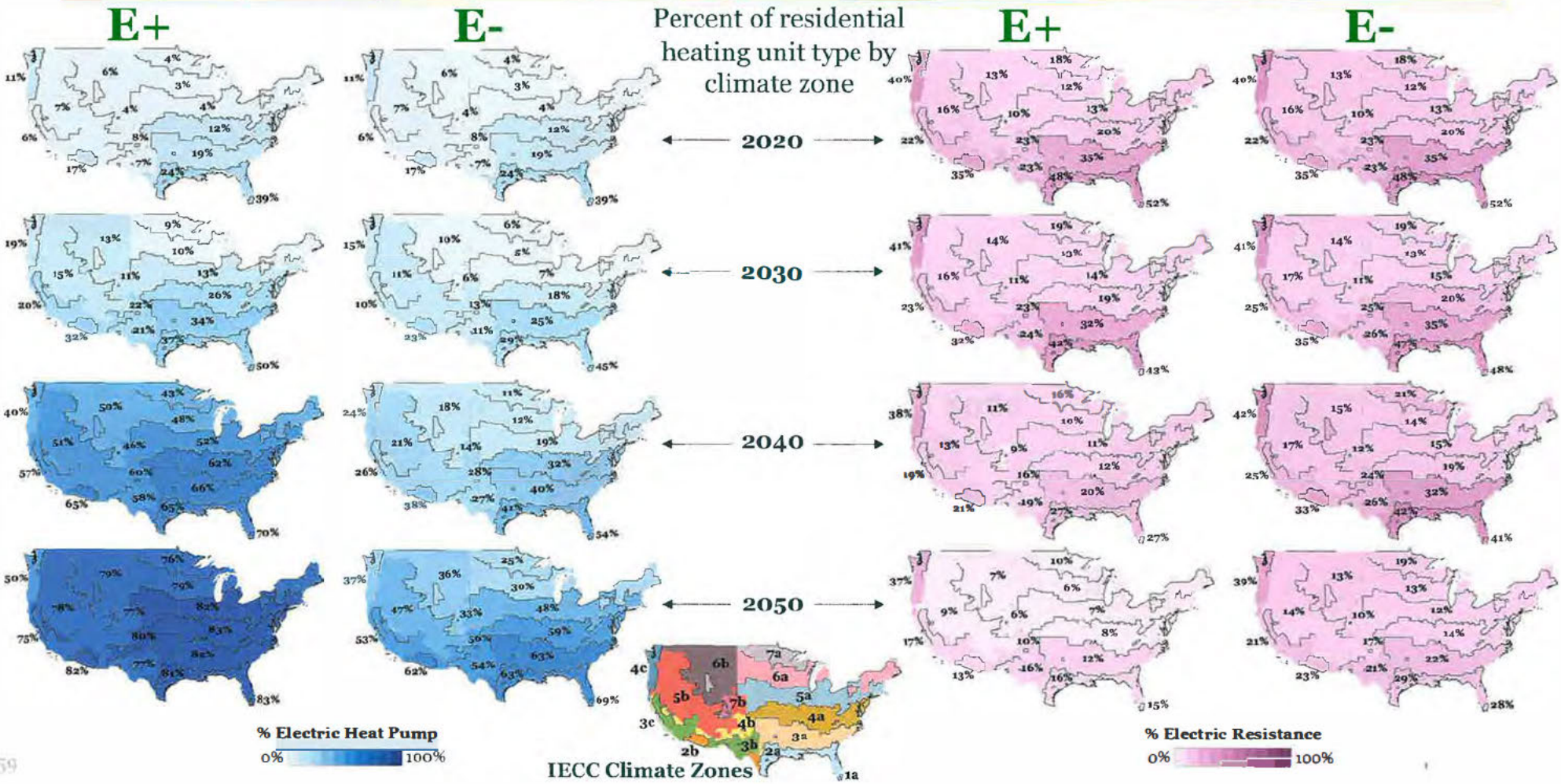
Electric home heating grows significantly, with the fraction adopting heat pumps varying significantly by climate zone.





Residential heat pumps grow from ~10% of the space heating stock in 2020 up to 80% (E+) or 54% (E-) by 2050.

E+



31M units
(23% of stock)

2030



81M units
(58% of stock)

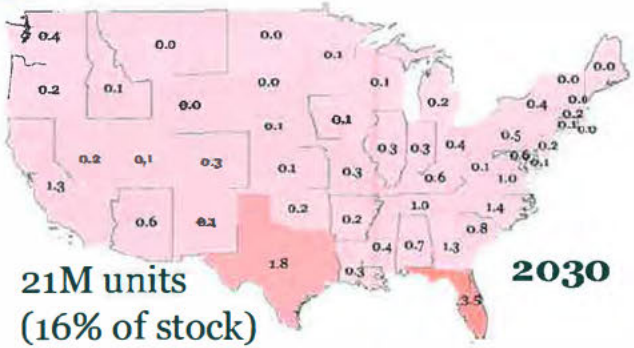
2040



119M units
(80% of stock)

2050

E-



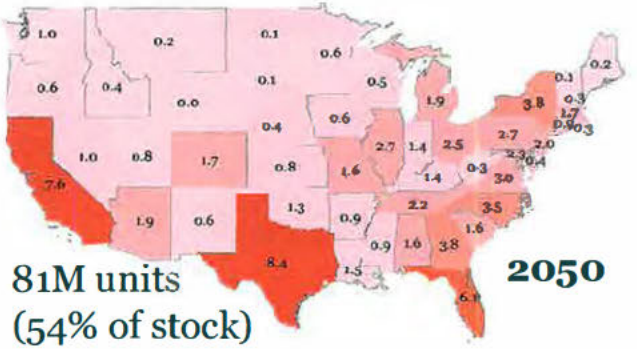
21M units
(16% of stock)

2030



41M units
(29% of stock)

2040



81M units
(54% of stock)

2050

Million Units

Number of homes using heat-pump heating by state 12

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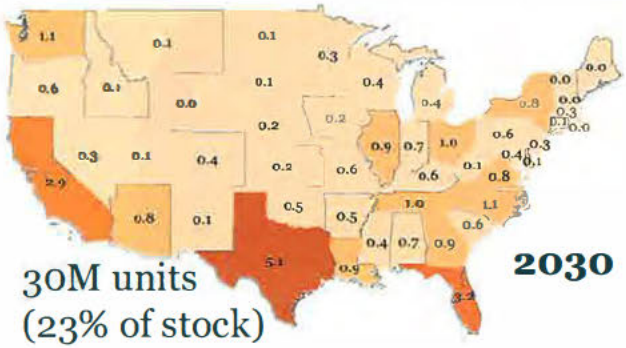
Residential electric resistance units decline from ~25% of the space heating stock in 2020 to 11% (E+) or 18% (E-) by 2050.

E+



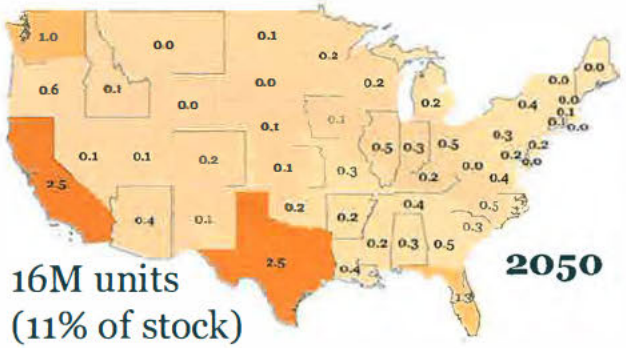
30M units
(23% of stock)

2030



23M units
(17% of stock)

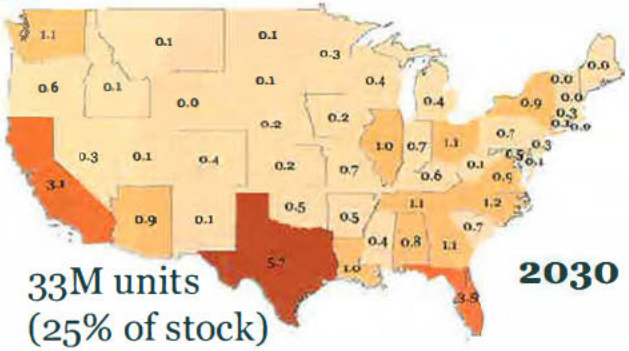
2040



16M units
(11% of stock)

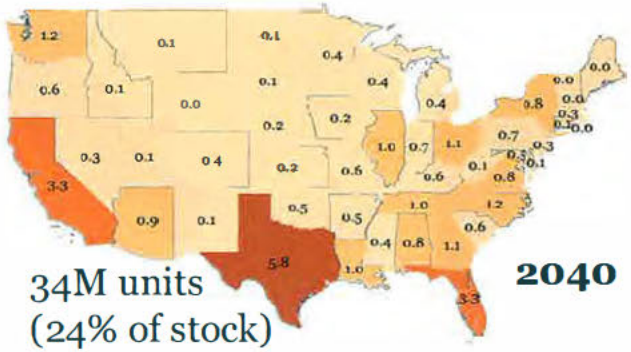
2050

E-



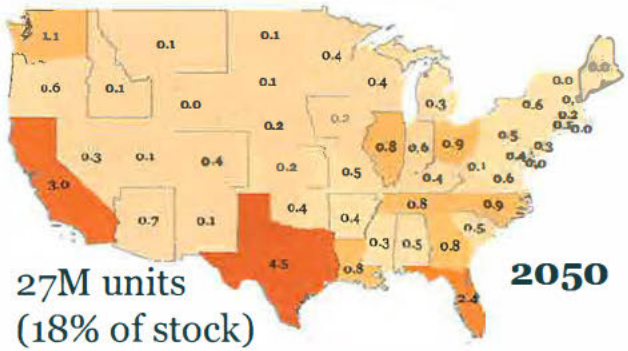
33M units
(25% of stock)

2030



34M units
(24% of stock)

2040



27M units
(18% of stock)

2050

Million Units

Number of homes using electric resistance heat by state: 0  6

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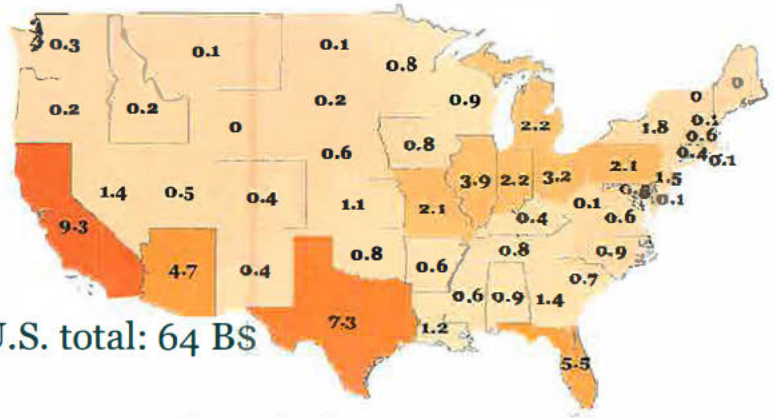
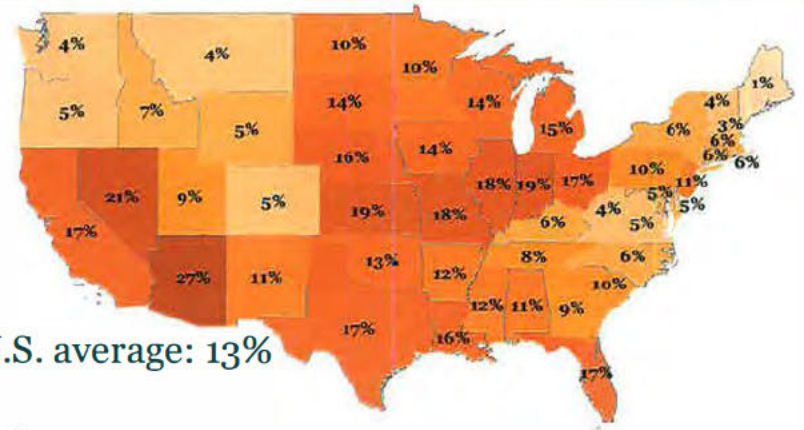
Capital expenditures from 2021-2030 for residential space and water heating are $60B to $70B higher than REF.

E+



U.S. total: 64 B$

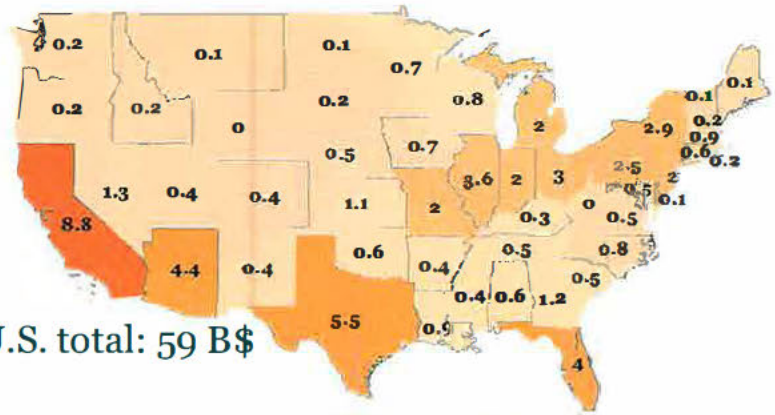


U.S. average: 13%

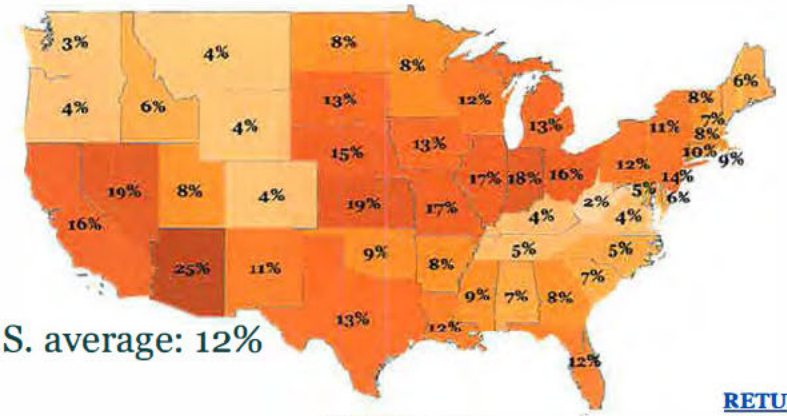
Incremental capital vs. REF

% increase vs. REF

E-



U.S. total: 59 B$



U.S. average: 12%

Billion 2018 $

0 16

2021 - 2030

% Difference

0% 25%

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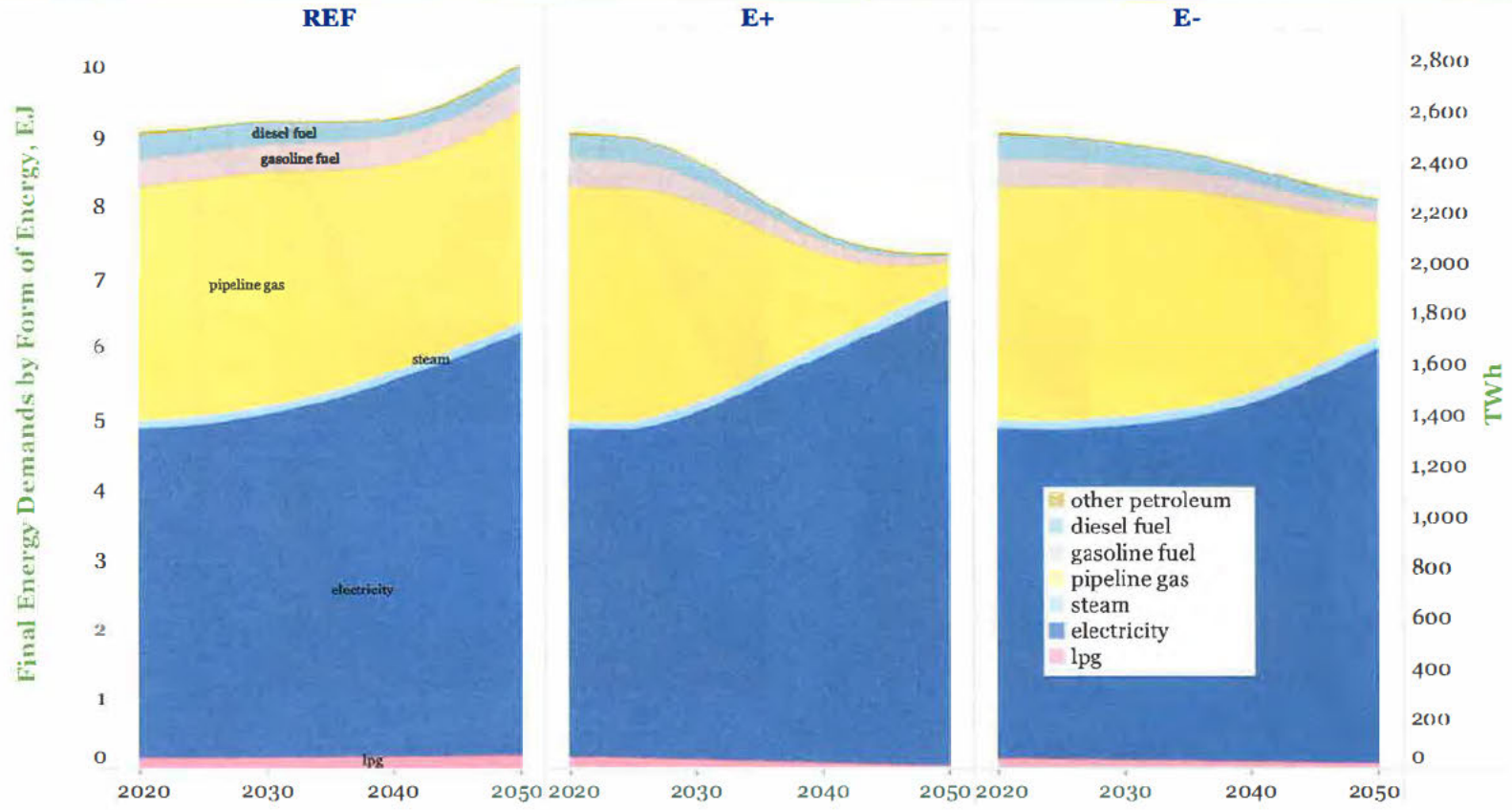
Commercial buildings' final energy use declines, and by 2050 electricity accounts for 90% in E+ and 70% in E-.



Note: All fuel values reported in this slide pack are on HHV basis.

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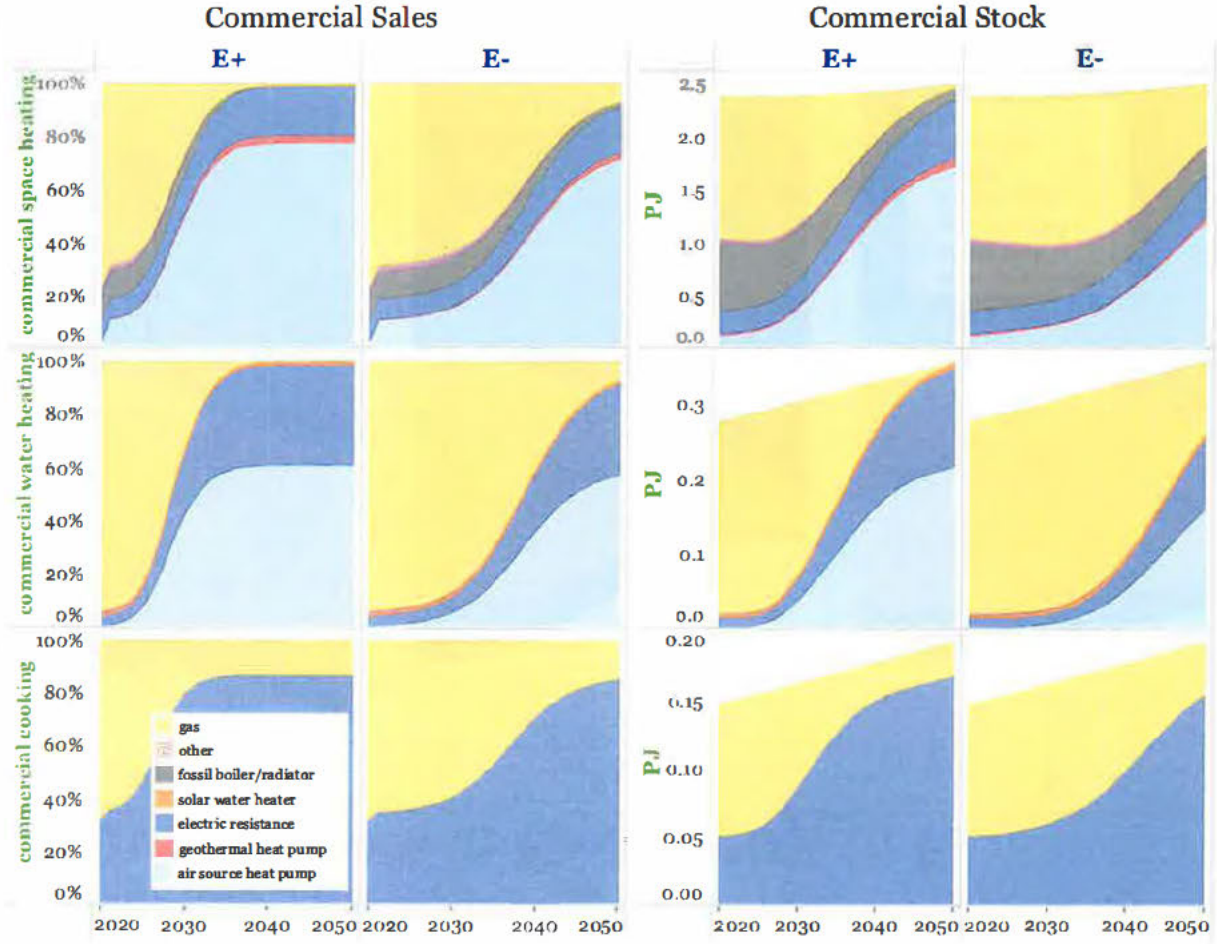
In the commercial sector (as in residential), investment choices shift rapidly to electricity for all energy services.



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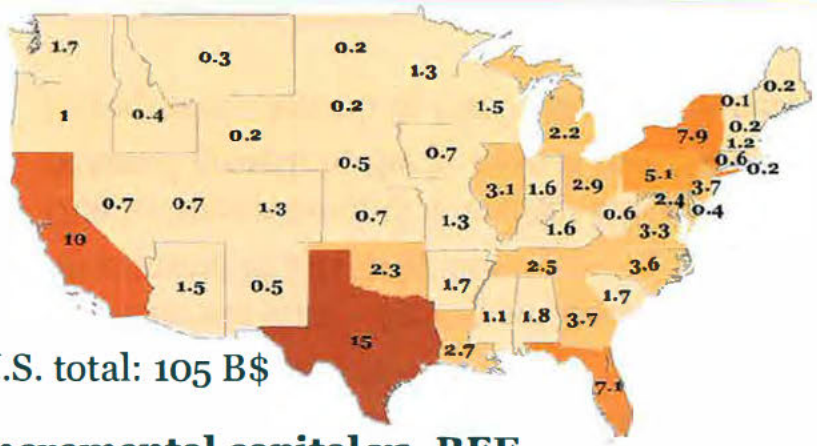
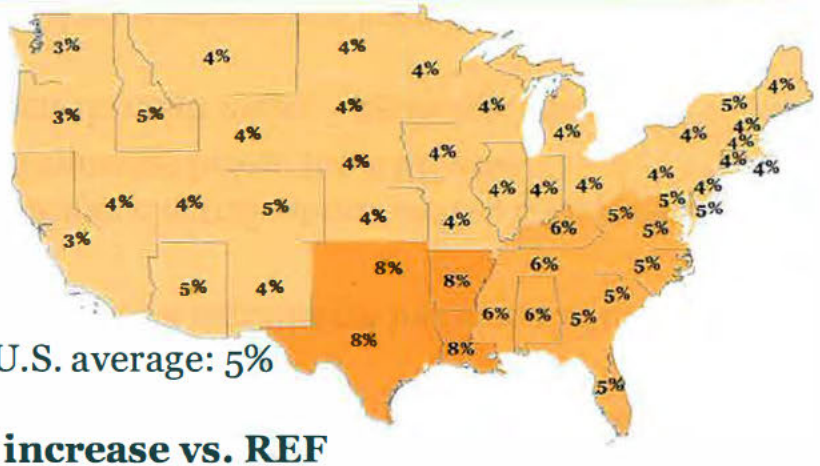
Capital expenditures from 2021-2030 for commercial HVAC and water heating are ~$100B to $110B (5%) higher than REF.

E+



U.S. total: 105 B$

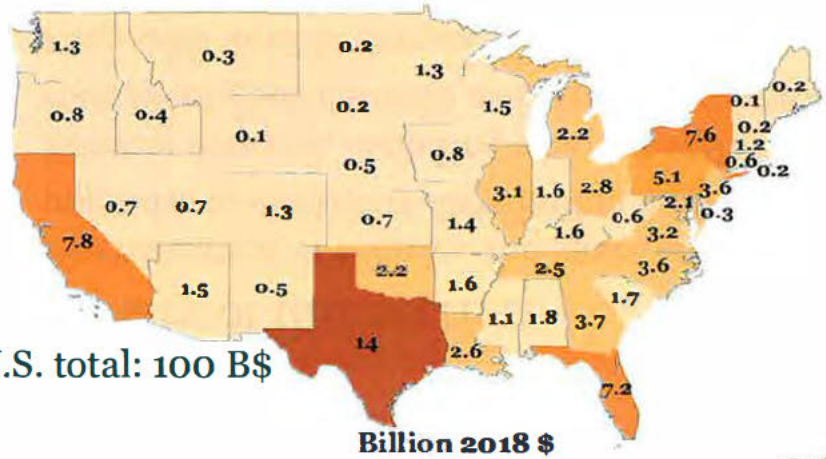


U.S. average: 5%

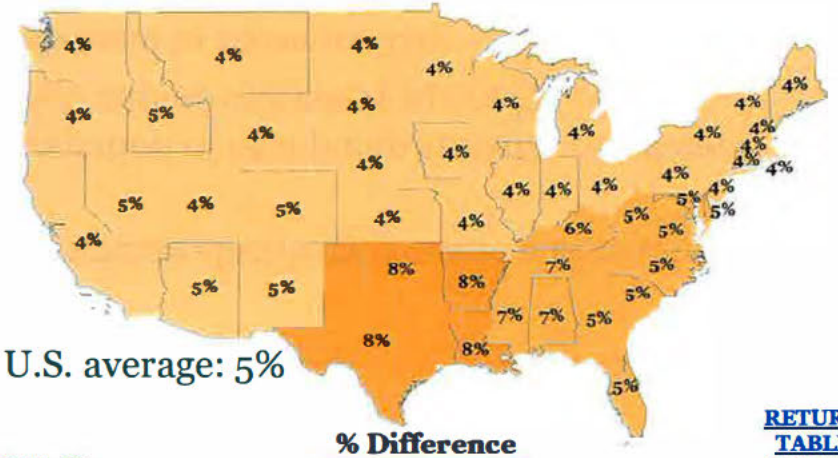
Incremental capital vs. REF

% increase vs. REF

E-



U.S. total: 100 B$



U.S. average: 5%

Billion 2018 $
0 — 16

2021 - 2030

% Difference
0% — 25%

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Electricity distribution system



Summary of this section

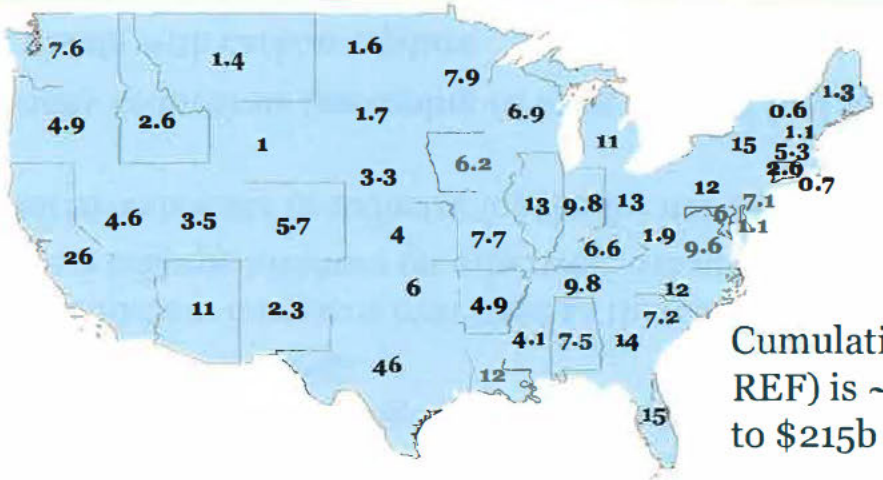
- Electrification of vehicles and space and water heating will increase electricity demand and require upgrades to electricity distribution networks
- Flexible demand, including smart charging of EVs and automation of heat pump systems, can reduce coincident peak demand and stress on distribution networks, minimizing costly upgrades
- Even with flexible demand,* distribution networks will likely need to accommodate ~5-10% increase in peak demand by 2030 and ~40-60% increase by 2050
- Approximately $370b in total distribution network investment is needed in the 2020s in E+ scenario, an increase of $15-20b vs REF.
- Investments total ~$700b per decade in the 2030s and 2040s, for a cumulative incremental capital investment of $215b by 2050.
- Due to improvements in energy efficiency (vs REF) and a slower electrification rate (vs E+), peak demand growth in the E- case is just 2% through 2030 and remains *below* the REF case.
- E- requires ~$300b in total distribution network investment through 2030, ~$50b *less* than REF.

* Our analysis of required distribution reinforcements assumes 50% of electric vehicle loads and 20% of heat pump water heating loads can be shifted to avoid contributing to peak loading of distribution assets

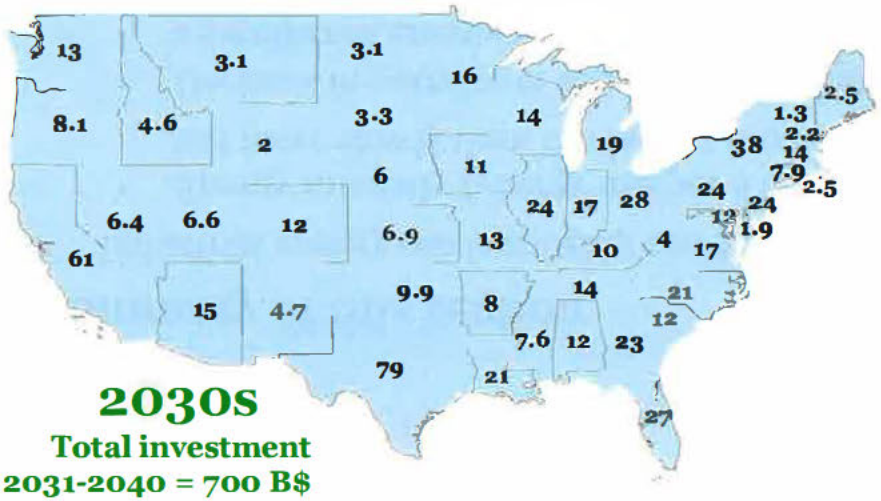
Electricity distribution investments are $370-700B per decade. Incremental capital (vs. REF) is ~$20B in 2020s & $215B by 2050.

E+ scenario

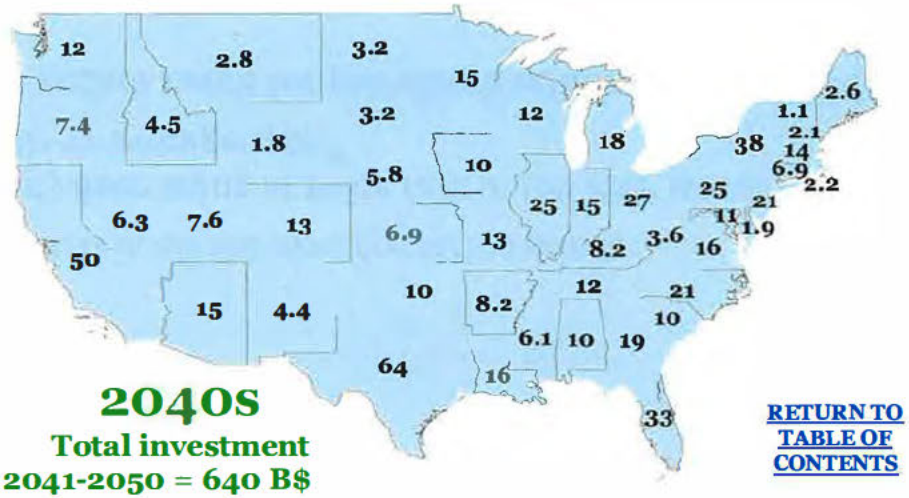
2020s
Total investment
2021-2030 = 370 B$



Cumulative *incremental* capital (E+ vs. REF) is ~$15-20B in 2020s, increasing to $215b by 2050.



2030s
Total investment
2031-2040 = 700 B$



2040s
Total investment
2041-2050 = 640 B$

(2018 $)

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Industrial sector

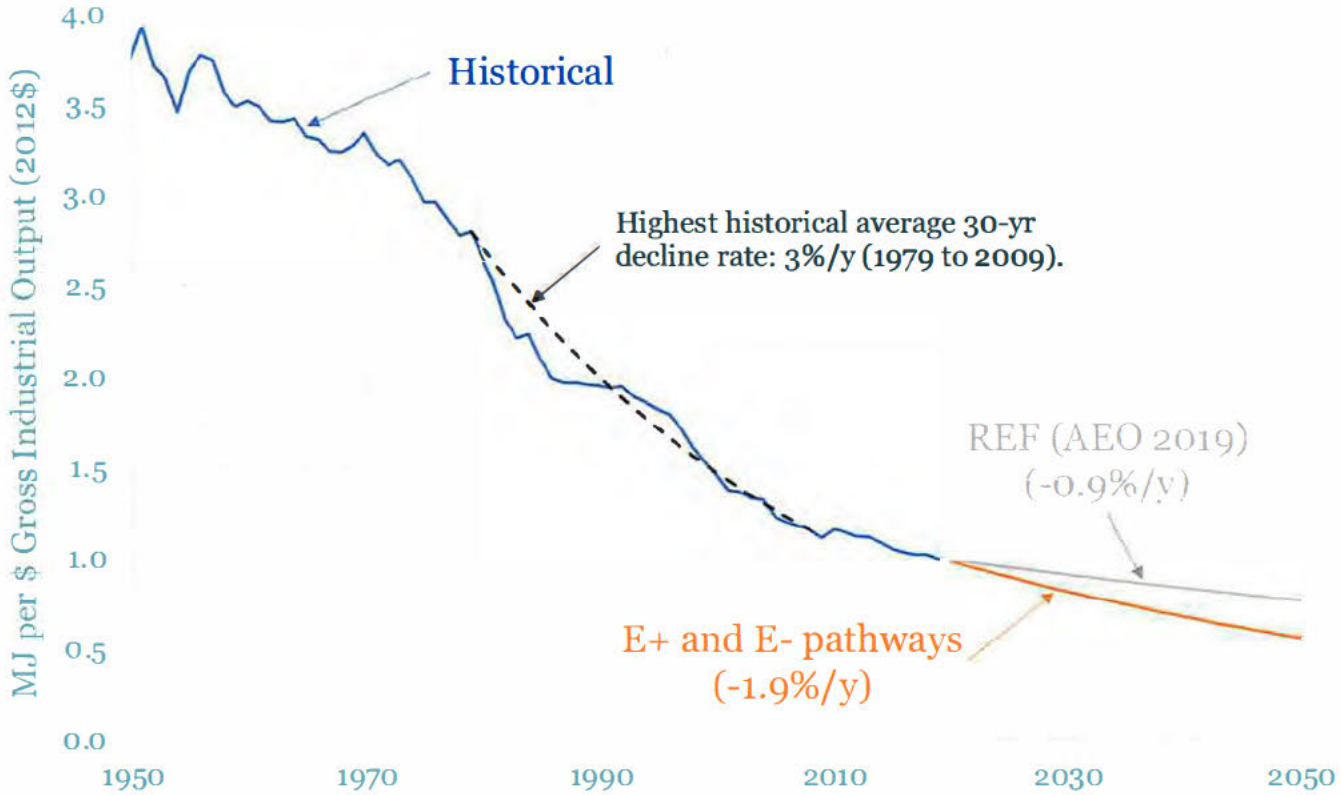


Summary of this section

- Industrial energy use is roughly constant during the transition in all net-zero scenarios due to:
  - Energy intensity (energy use per $ of industrial output) decreasing at twice rate in the REF scenario, but more slowly than the fastest recorded historical 30-yr average rate.*
  - Declines in petroleum use across the economy, which reduce needs for petroleum refining, which is a significant energy using sector today.
  - A shift over time toward electric arc furnace steel making and direct-reduced iron production using hydrogen increases the electricity and hydrogen use in industry, but these are offset by reductions in fossil fuel use for iron and steel making.
  - Energy use for cement production increases over time as this industry is decarbonized through use of CO_2 capture applied as a tailpipe measure on otherwise conventional cement production.
- During the 2020s, the capital investments in industry for the for net-zero pathways include, approximately
  - 250 B$ for energy intensity reductions (assuming 10 to 15 $/GJ of fuel saved)
  - 60 B$ for new cement plants with carbon capture
  - 8 B$ for new direct-reduced iron facilities that operate using hydrogen for both fuel and reductant.

U.S. industrial energy intensity continues its declining trend of past two decades; electrification has less impact than in other sectors.

- Same-fuel energy productivity improves at double the rate in REF.
- Relatively modest fuel → electricity switching, except for iron and steel, where electric arc furnaces grow to 100% of steel-making by 2050. Scrap feedstocks are supplemented with direct-reduced iron made using H_2.



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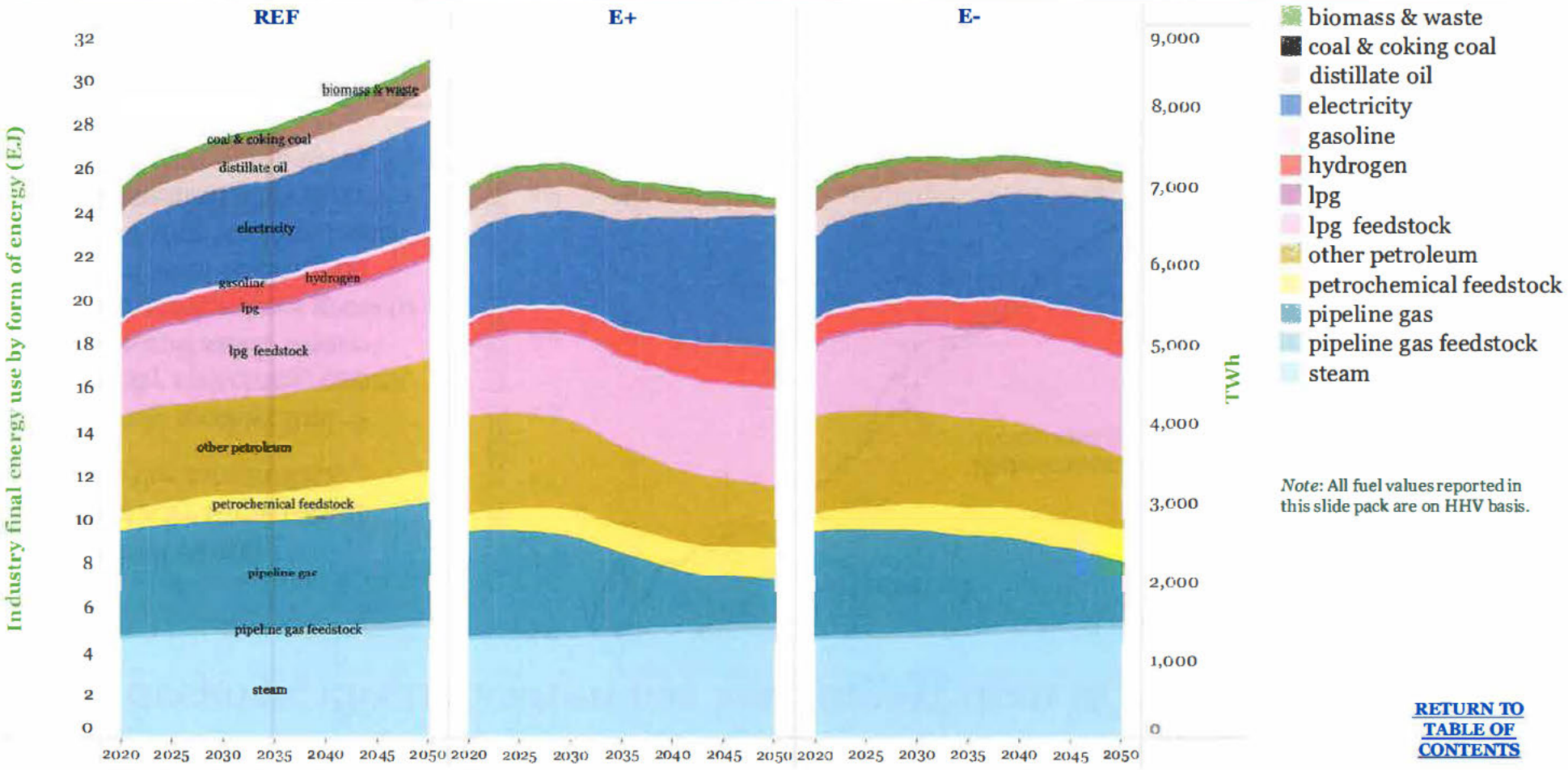
Industrial final energy in 2050 is 15-20% below REF. Roles for electricity and H_2 grow; use of liquids and other gases decline.



Note: All fuel values reported in this slide pack are on HHV basis.

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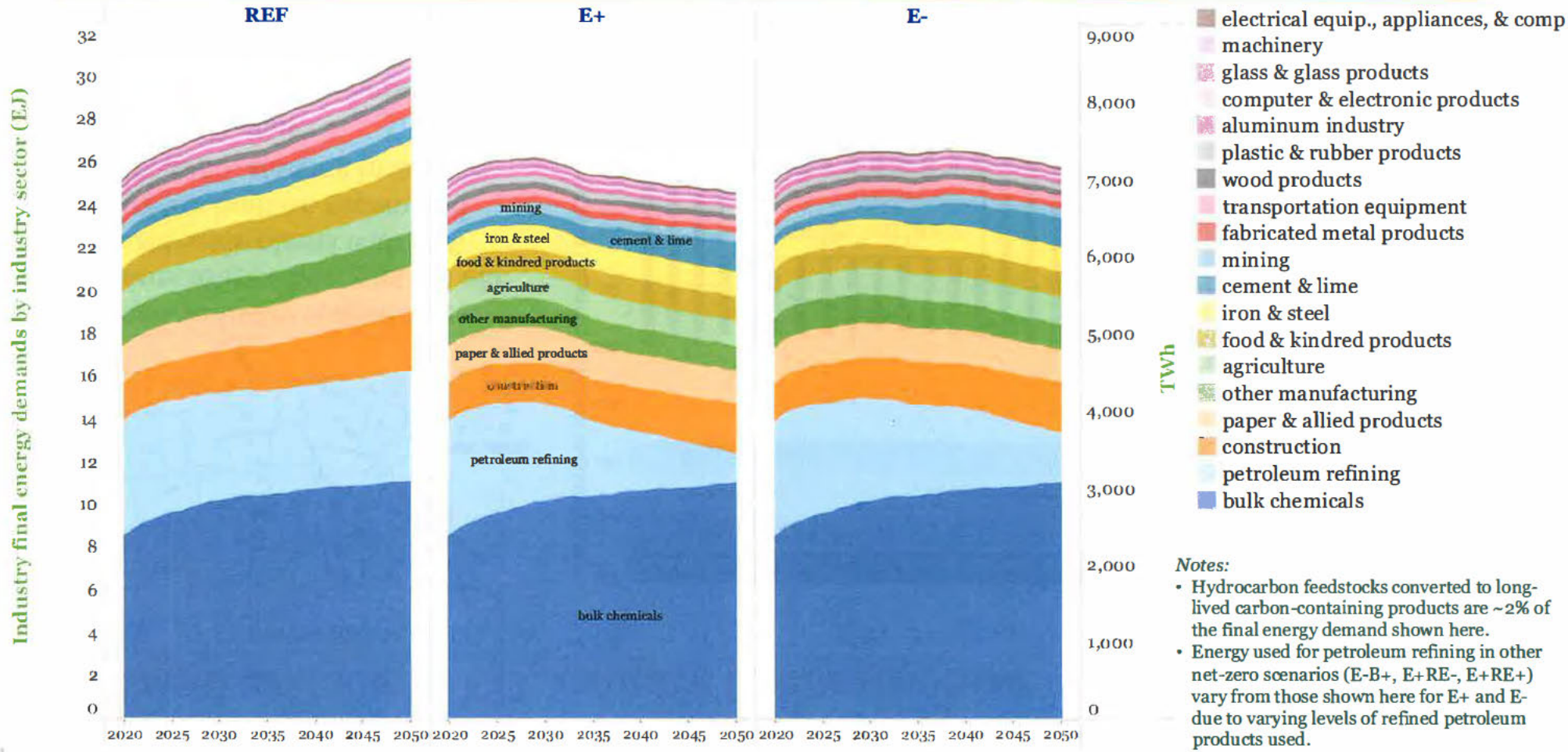
Bulk chemicals remains the largest industrial energy user. Petroleum refining energy use falls. Cement and lime energy use grows.



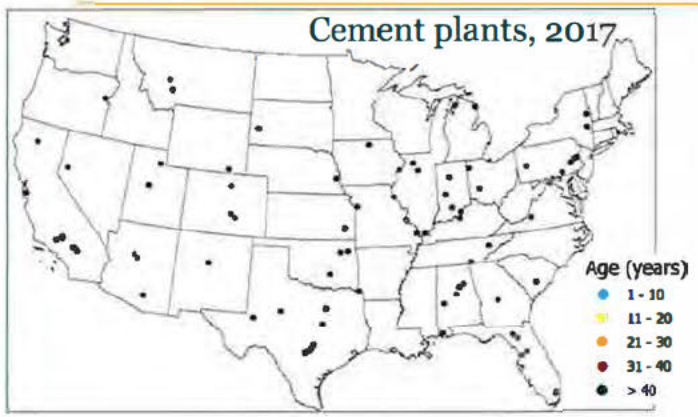


Notes:

- Hydrocarbon feedstocks converted to long-lived carbon-containing products are ~2% of the final energy demand shown here.
- Energy used for petroleum refining in other net-zero scenarios (E-B+, E+RE-, E+RE+) vary from those shown here for E+ and E- due to varying levels of refined petroleum products used.

Note: All fuel values reported in this slide pack are on HHV basis.

Energy use in cement/lime making grows due to growth in cement demand and use of CO_2 capture to decarbonize



For net-zero, industry consolidates:

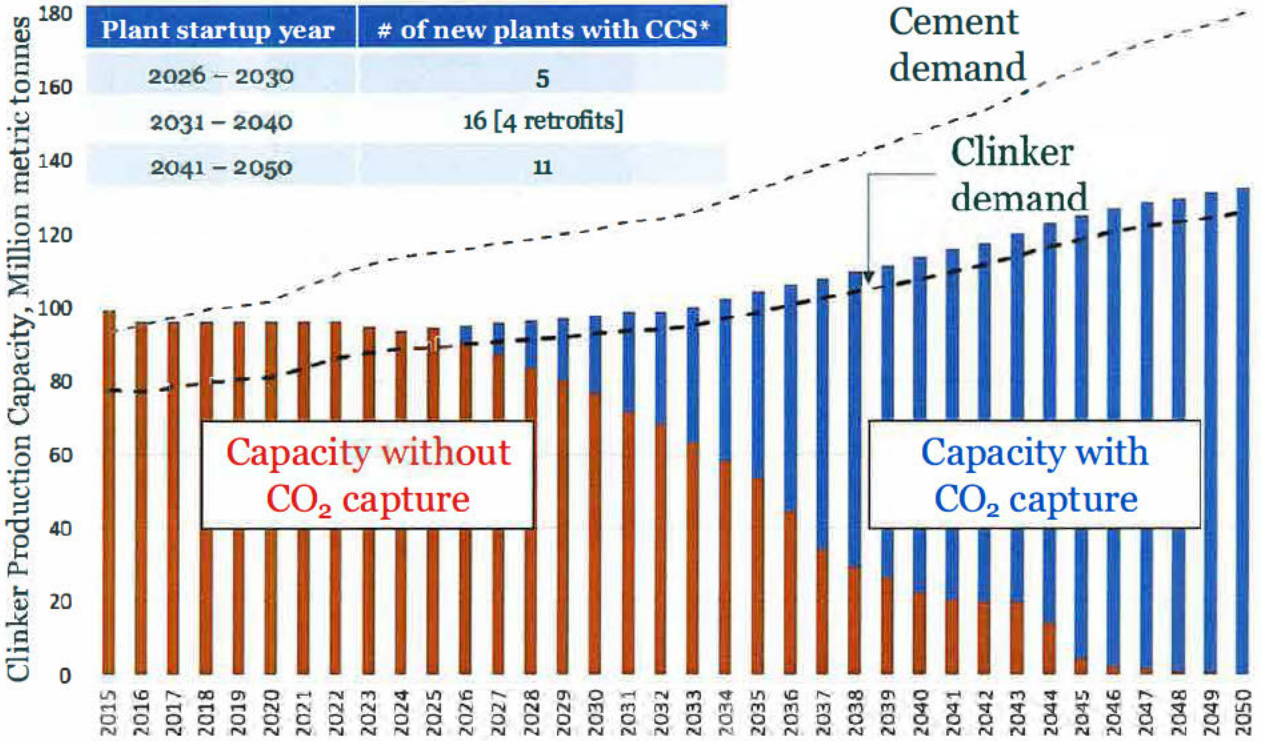
- 92 plants retire when ≥ 35 yrs old.
- 35 world-scale plants with CO_2 capture are built on brownfield sites by 2050, starting in 2020's.

Each world-scale plant:

- Costs ~$3.5 billion to build.
- Captures ~2.5 million tCO_2/y

124 million tCO_2 from cement are captured in 2050 (90% capture rate).

Plant startup year	# of new plants with CCS*
2026 – 2030	5
2031 – 2040	16 [4 retrofits]
2041 – 2050	11



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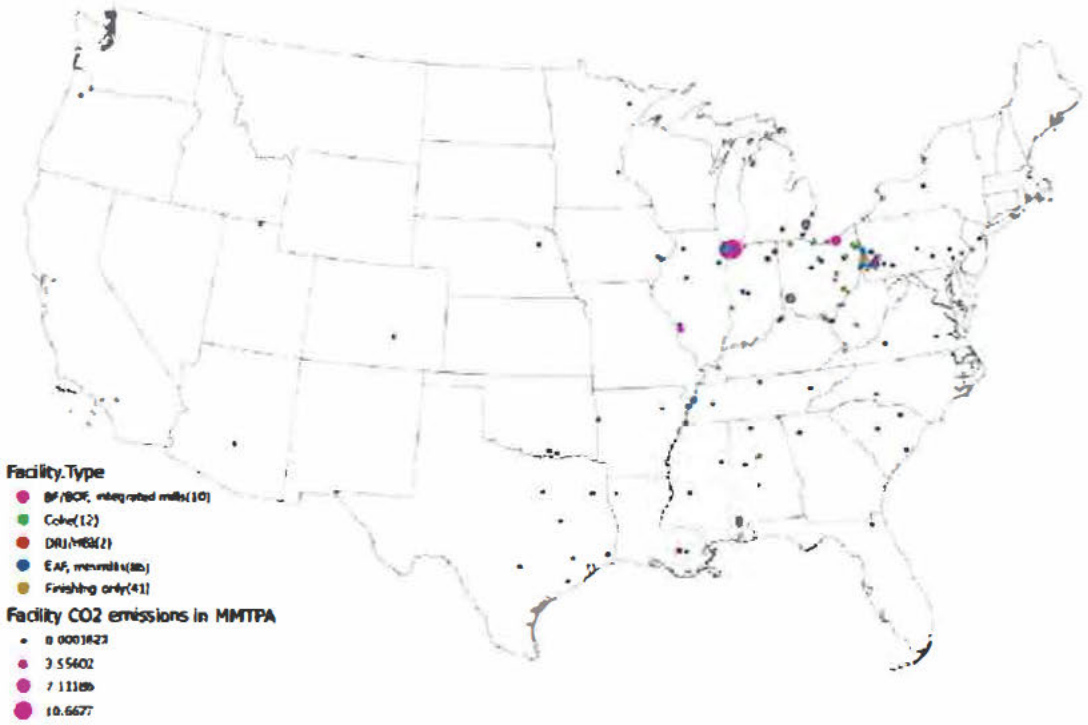
U.S. iron and steel production (~90 million t/y) accounts for 106 million tCO_{2e}/y of emissions today (1.8% of total U.S. emissions).

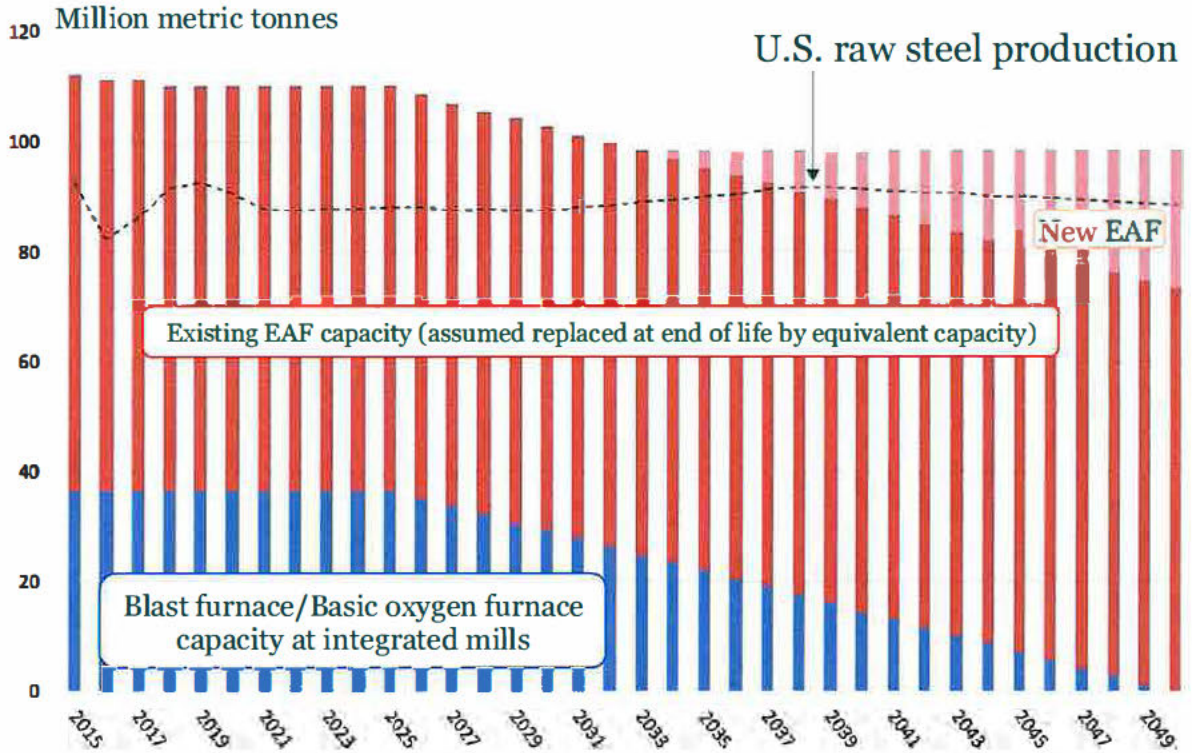


- Current US steel production is:
  - 32% via integrated iron & steel mills (with blast furnace/basic oxygen furnaces, BF/BOF) accounting for 69% of I&S CO_2 emissions.
  - 68% via electric arc furnaces (EAF) using recycle scrap and some pig iron from BF/BOF, accounting for 31% of I&S CO_2 emissions.
- Distribution of mill types:
  - All nine operating integrated mills are in the Eastern US.
  - Two direct-reduced iron (DRI) facilities are on the Gulf Coast.
  - Approximately 100 electric arc furnace (EAF) steel mills are widely dispersed.



Steel industry evolves to 100% electric arc furnaces (EAF) by 2050; scrap is supplemented by direct-reduced iron (DRI) made using H_2.

- US domestic steel production holds steady at ~90 million t/y to 2050 (AEO2019).
- EAF production grows, producing 100% of domestic steel by 2050.
- Scrap supply for EAF grows to 59 MMT/y by 2030 and plateaus there.
- Scrap is supplemented by raw steel from direct reduction of iron (DRI) using H_2 as fuel and reductant.
- Average of 1.5 MMT/y of DRI capacity comes on line annually from 2030 to 2050 and an equivalent amount of BF/BOF (and associated coke production) retire. All BF/BOF are retired by 2050.
- DRI plants are geospatially distributed in proportion to current installed EAF capacity, except none in Northeast.



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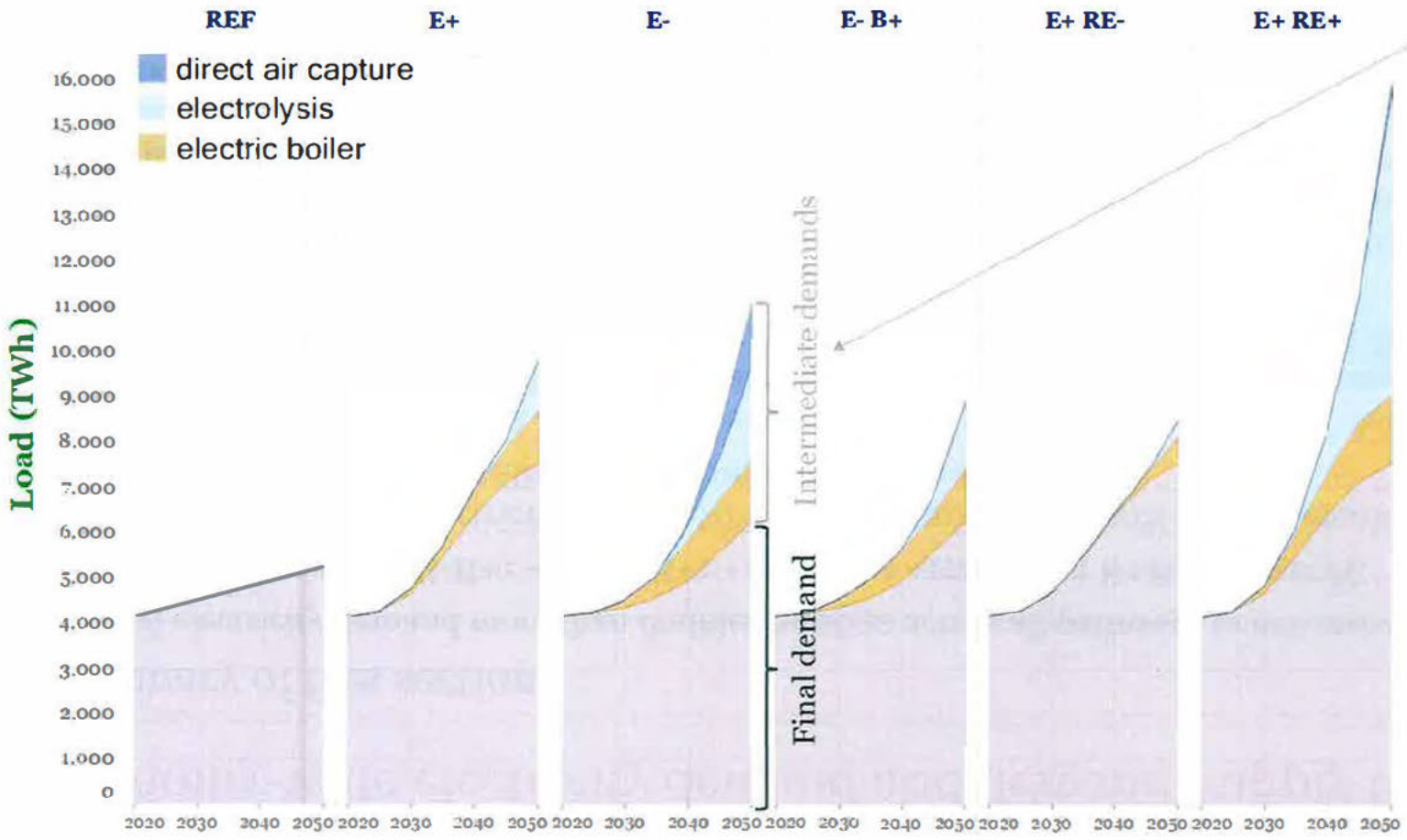
Economy-wide electricity demand and demand-supply balancing

Summary of this section

- Total electricity demand more than doubles by 2050 across all pathways to net-zero:
  - **E+RE-:** +115%; **E-B+:** +125%; **E+:** +145%; **E-:** +170%; and **E+RE+:** +300%.
- End-use demand for electricity grows ~50% in E- scenarios and ~90% in E+ scenarios through 2050, driven by the pace of electrification of transportation and heating.
- Large volumes of *additional* electricity are consumption by several 'intermediate' demands—electrolysis, electric boilers (installed in parallel with gas boilers) for industrial process heat, and direct air capture—all of which can flexibly consume low-cost, carbon-free electricity (e.g. from wind and solar power) when available and stop consumption when electricity supply is limited.
- If biomass supplies are constrained, falling shorter on electrification of end uses can actually result in *greater* electricity consumption (see E- vs E+). Even more electricity must be devoted to intermediate loads to produce hydrogen and power direct air capture devices to supply or offset greater demand for liquid and gaseous fuels in transportation and heating. Alternatively, biomass use can expand to supply liquid and gaseous fuels (as in E-B+), with significant land use implications.
- Flexible scheduling of EV charging and electric water heating, large intermediate flexible loads, batteries, and firm generation technologies all help compensate for variability in wind and solar power and ensure electricity supply and demand are always balanced.

Electricity load grows 2x – 4x by 2050, including flexible intermediate loads that absorb variable wind and solar generation.



Intermediate demands are flexible loads:

- Electrolysis making H_2 from water (hourly flexibility).
- Electric boilers in parallel with gas-fired units in industry (hourly flexibility).
- Direct air capture (daily flexibility).

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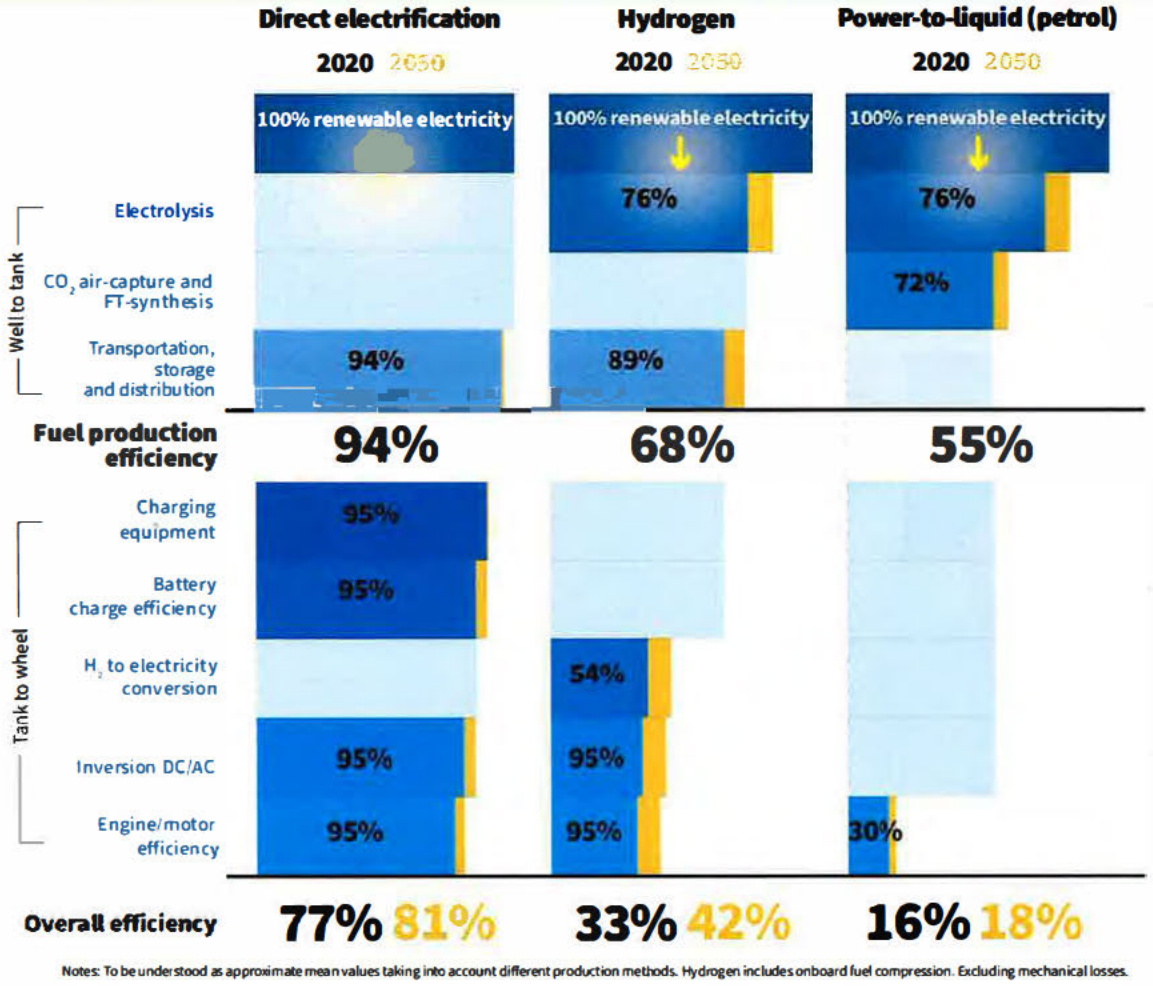
Fueling vehicles with hydrogen or liquids made from electricity requires much more electricity than using it directly in EVs.

Electricity-to-wheels efficiency of various zero-carbon vehicle pathways



Notes: To be understood as approximate mean values taking into account different production methods. Hydrogen includes onboard fuel compression. Excluding mechanical losses.

Adapted, with permission, from Transport and Environment, "Electrofuels? Yes, we can ... if we're efficient." December 2020.

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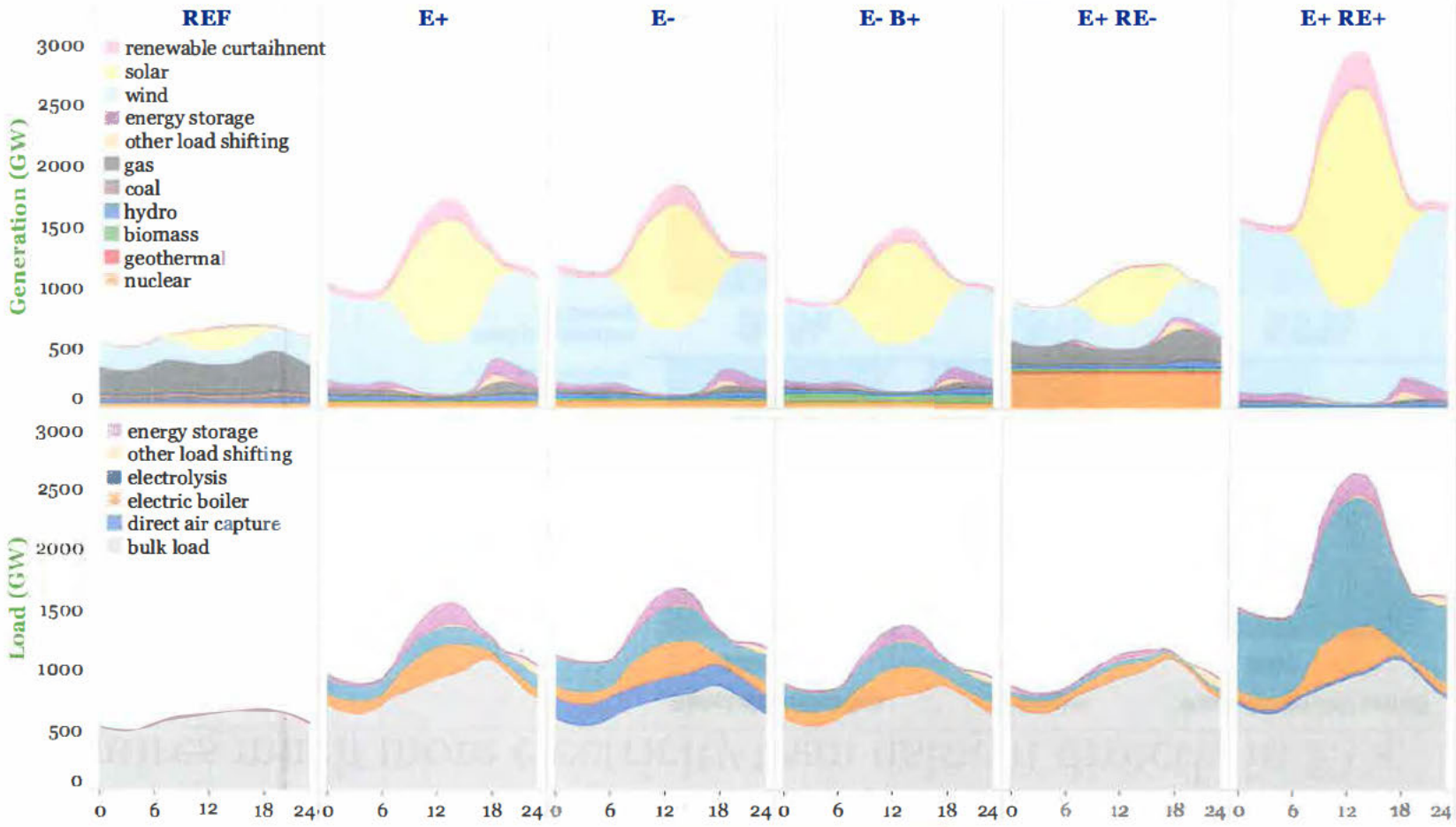
Hourly average grid operations: Short-duration batteries play relatively small roles. Large role for electrolysis in RE+ and E-.



Note: "Other load shifting" represents up to 50% of EV charging load and up to 20% of residential & commercial water heating load that are shifted in time relative to typical consumer patterns. In the RIO model, EV charging can be delayed by up 5 hours and water heating can be advanced or delayed by up to 2 hours. When EV and water heating loads are higher than with typical behavior, they are shown here as load. When they are lower than with typical behavior they are shown as generation. Meanwhile, "bulk load" includes EV and water heating loads under typical consumer behavior. Thus, the "other load shifting" seen here reflects load shifting from early evening to late evening.

If the option of shifting EV and water heating loads were removed, the amount of required energy storage approximately doubles.

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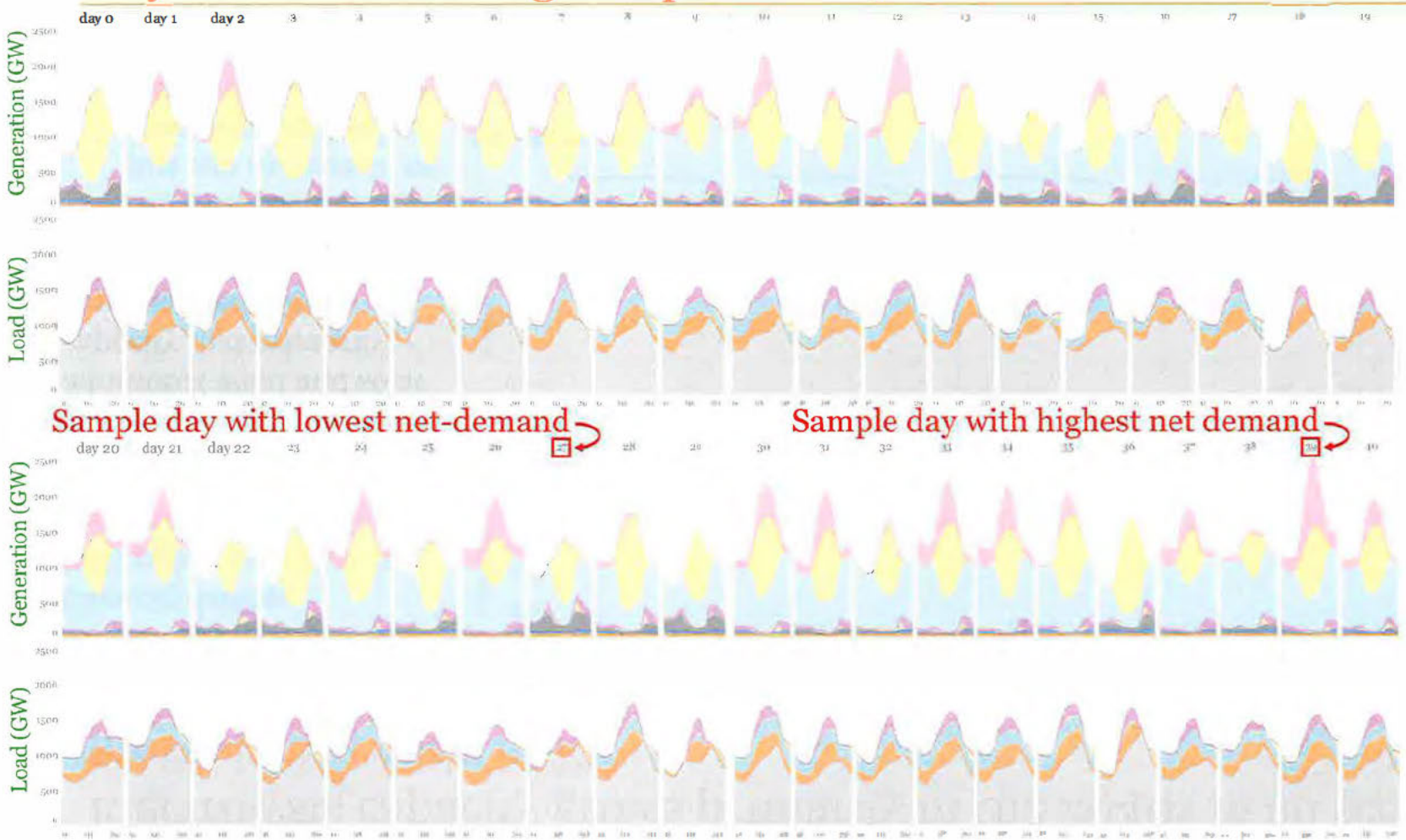
Hourly generation and load profiles in 2050 for each of 41 sample days used to model grid operations, E+ scenario.





Generation

- renewable curtailment
- solar
- wind
- energy storage
- other load shifting
- gas
- coal
- hydro
- biomass
- geothermal
- nuclear

Load

- energy storage
- other load shifting
- electrolysis
- electric boiler
- direct air capture
- bulk load

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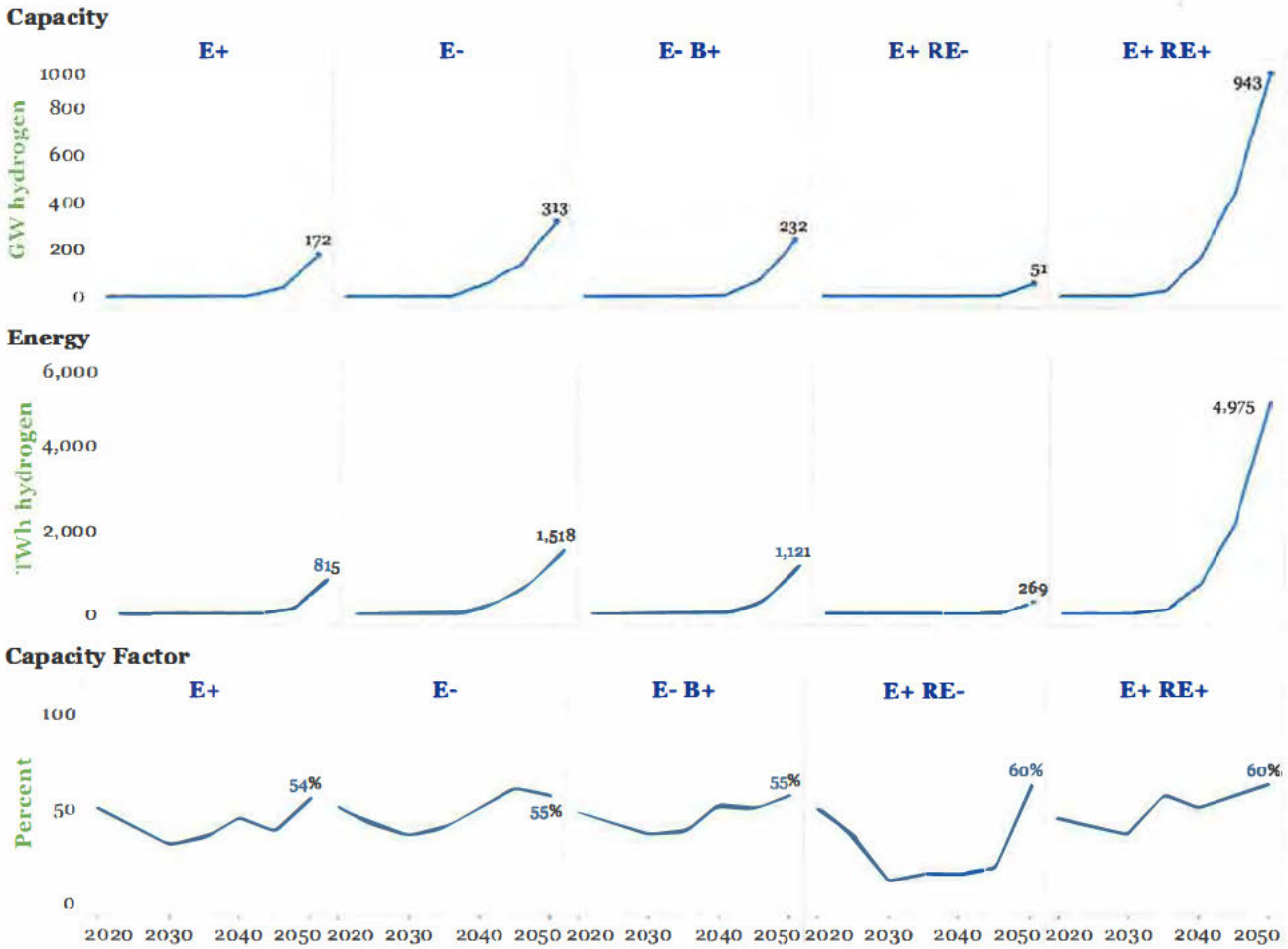
Electrolysis capacity grows primarily in the 2040s in all scenarios, most significantly in RE+.

- Capacity factors (utilization rates) are in the range of 40-60%
- Plants run frequently, requiring substantial additional wind and solar capacity that primarily supplies electrolysis.
  - In other words: electrolysis doesn't just run on 'excess' or 'free' wind and solar that would otherwise be curtailed.



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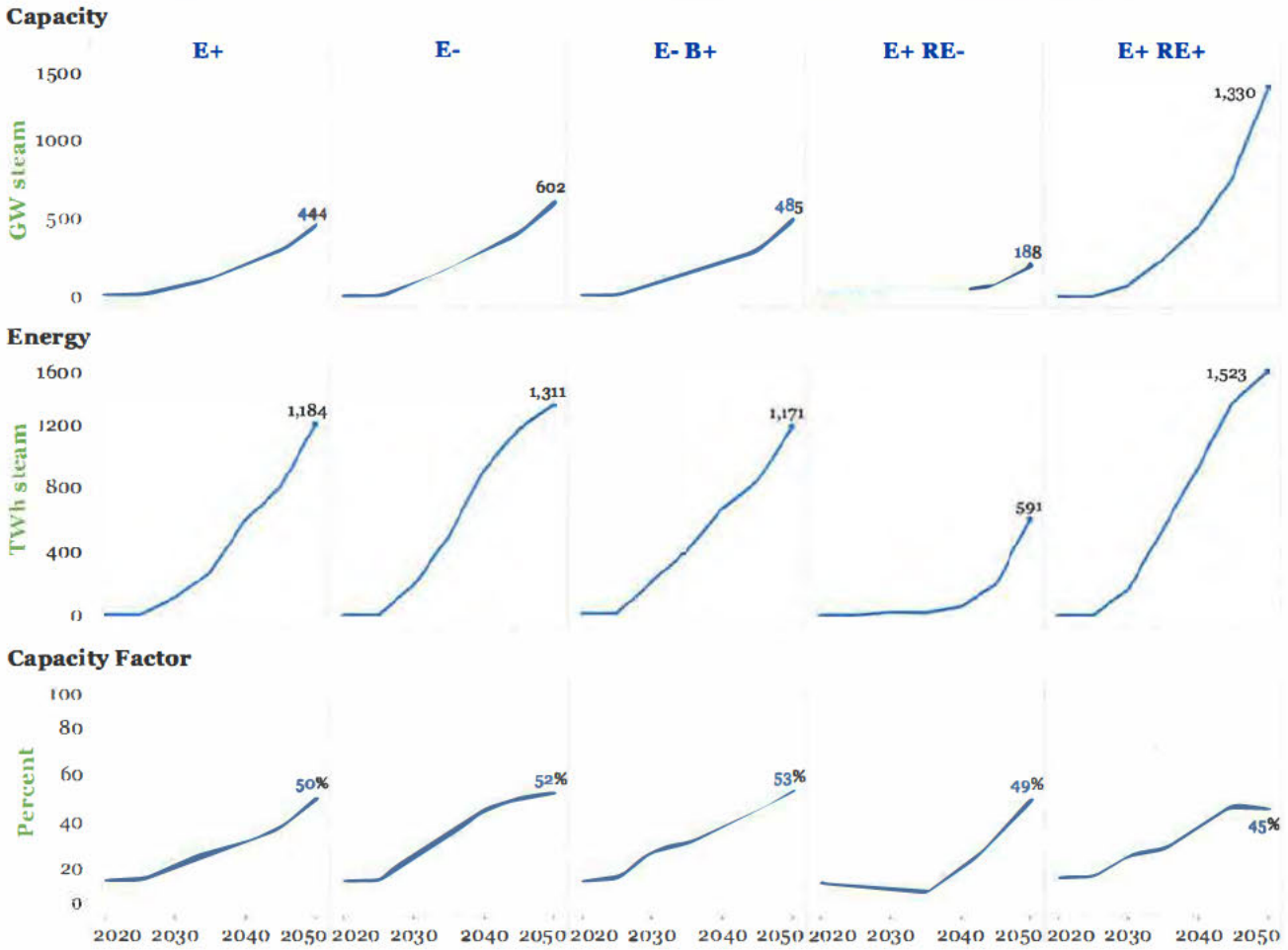
Electric boilers are deployed alongside gas boilers for industrial process heat.

- Allows variable wind and solar generation when available to displace fossil gas while maintaining 100% availability of heat.
- Electric boiler capacity and utilization grow steadily from 2025 to 2050 except in RE-.



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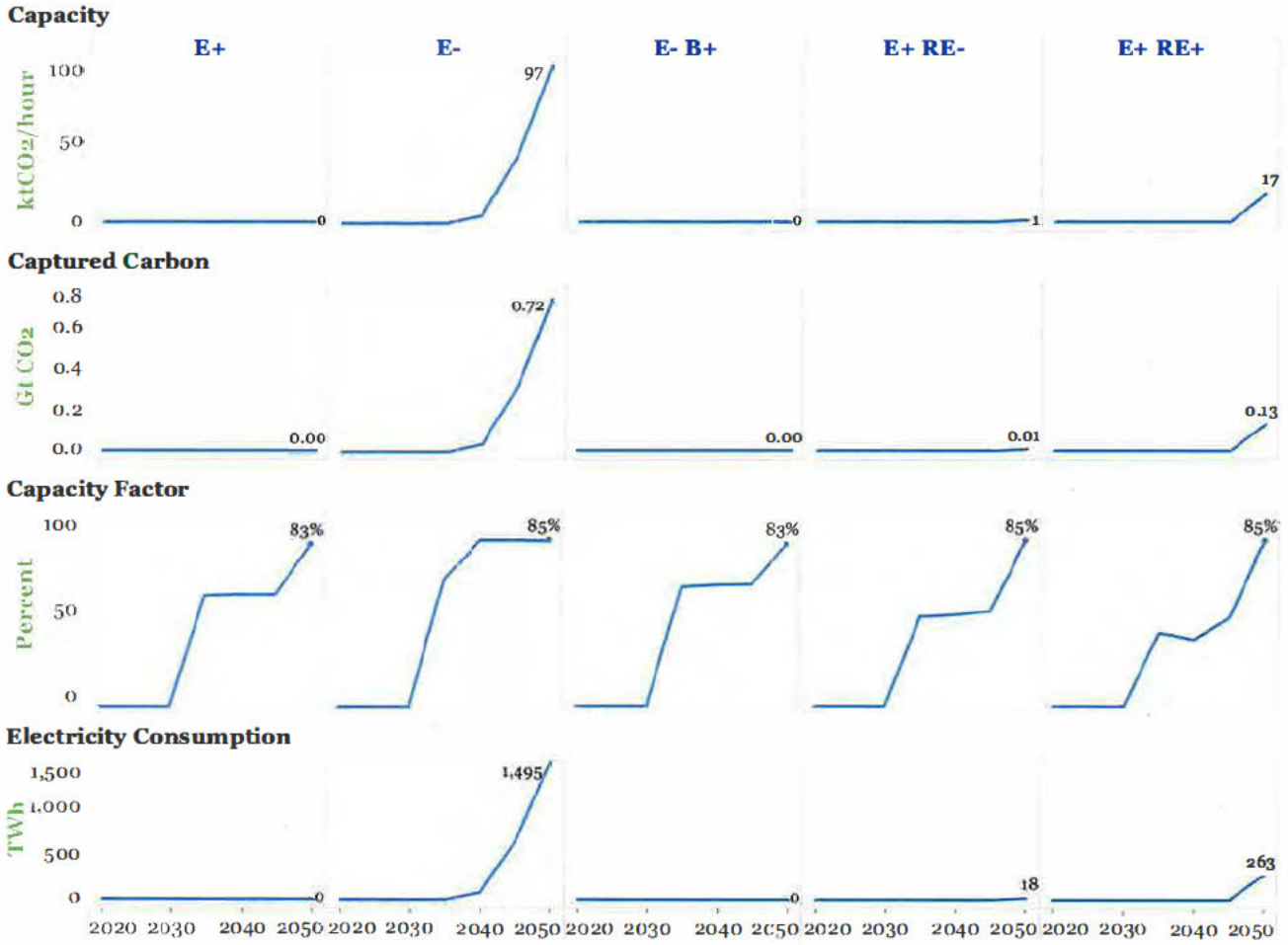
Direct air capture of CO_2 is significant in E- and RE+ scenarios

- With lower electrification of transportation (and biomass fully utilized) in E-, DAC allows for greater use of liquid and gaseous fossil fuels.
- In RE+ CO_2 from DAC is used as carbon source for synthetic liquid and gaseous fuels.
- Given capital-intensity of DAC, utilization rates are high (50-85%).



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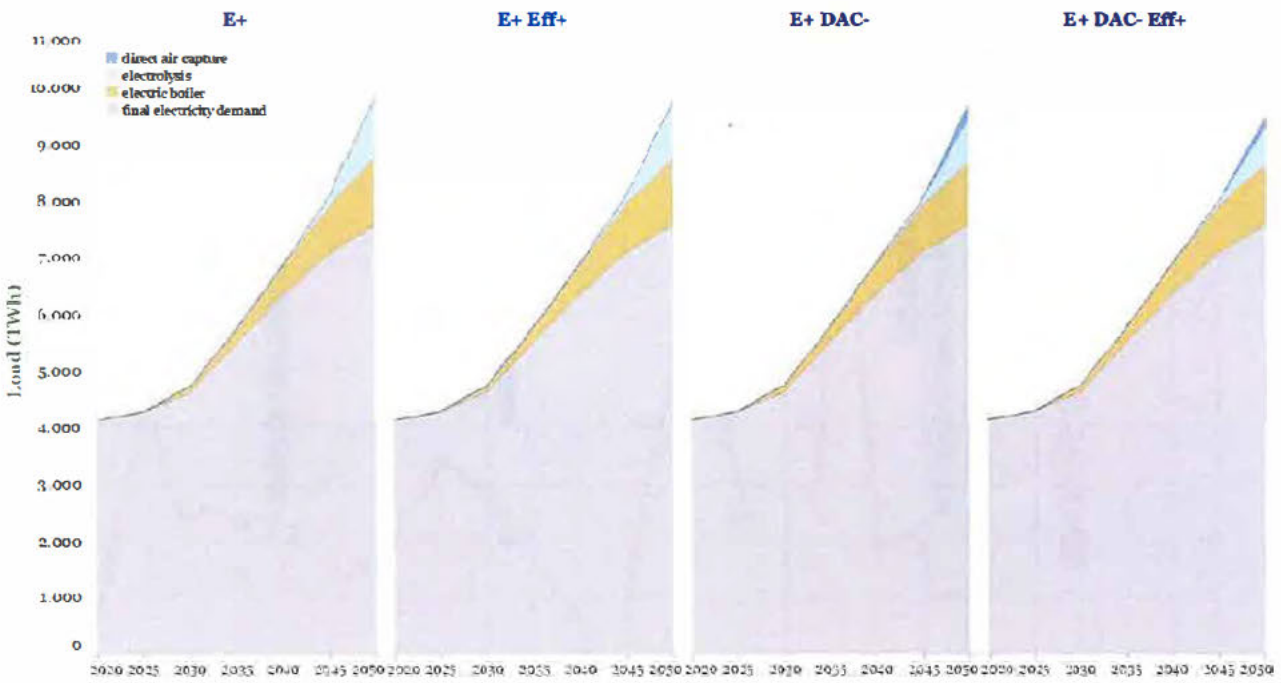
Lower capital cost and/or higher electricity efficiency of direct air capture increases its use slightly in E+ and decreases electrolysis

The role of direct air capture (DAC) in future decarbonized energy systems is of significant interest. Relative to E+:

- Lowering DAC capital cost to ~1/3 of E+ (E+ DAC-) leads to only a small increase in DAC load because DAC is still more costly for CO_2 removal than other options. Electrolysis is slightly less utilized.
- Halving assumed DAC electricity use per tonne of CO_2 captured (E+ Eff+) leads to an even smaller increase in DAC load, with little change in electrolysis use.
- Combining lower cost *and* higher efficiency for DAC (E+ DAC- Eff+) reduces electrolysis load and total load more appreciably.
- NPV of total energy-supply system costs (2020 – 2050) is nearly the same for all cases shown.



Input assumptions that vary between cases

	E+	E+ DAC-	E+ DAC eff+	E+ DEC- eff+
Capital cost, $/($tCO_2$/y), 2016$	2,164	694	2,164	694
Electricity use, MWh/tCO_2 captured	2	2	1	1

DAC cost and efficiency in E+ based on Socolow, et al., 2011.
DAC cost in DAC- based on Keith, et al, 2018.

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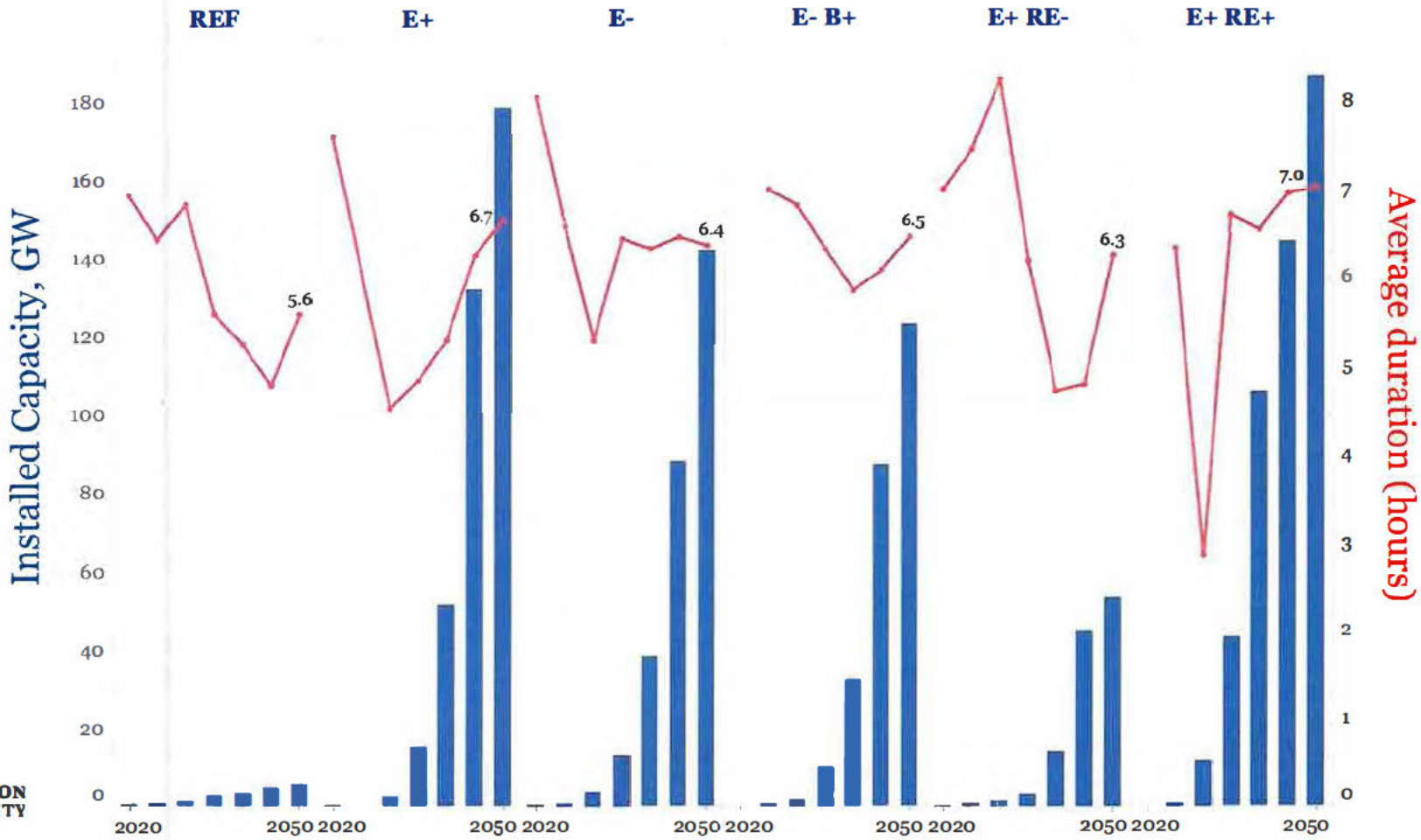
Grid battery capacity grows (mostly after 2030) to handle intra-day flexibility needs (5 to 7 hours storage duration)



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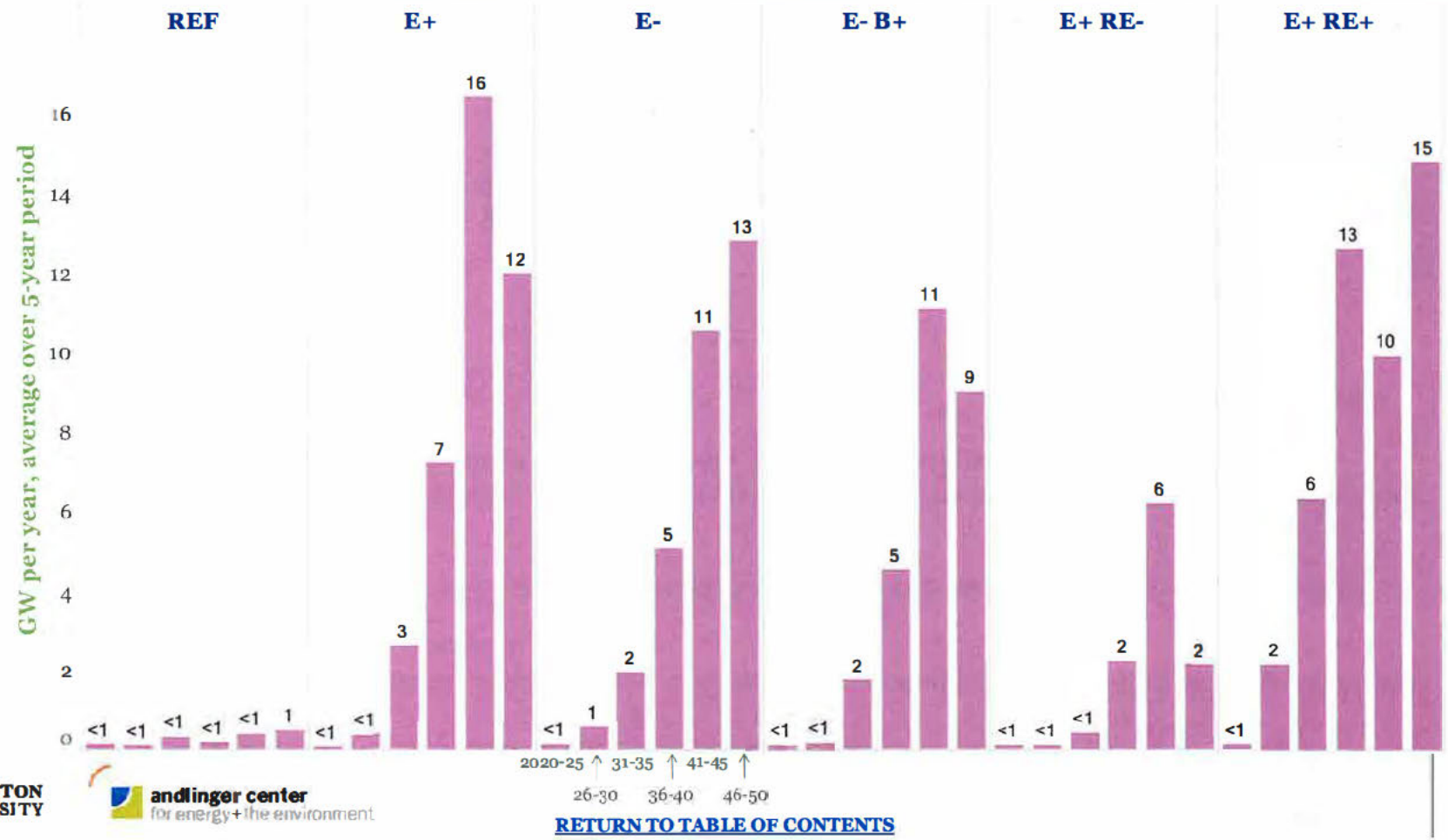
Annual build rates for grid batteries are relatively modest through the 2030s, increasing thereafter.



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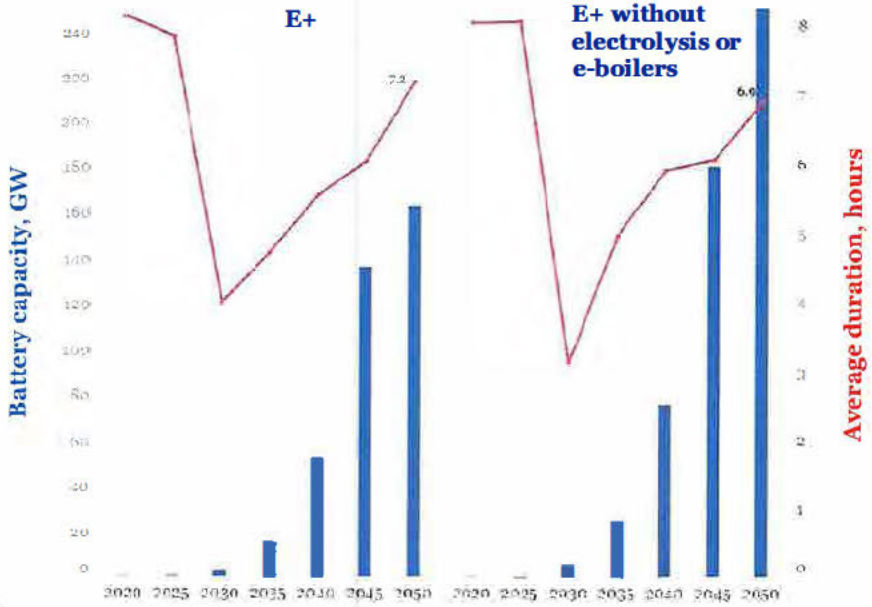
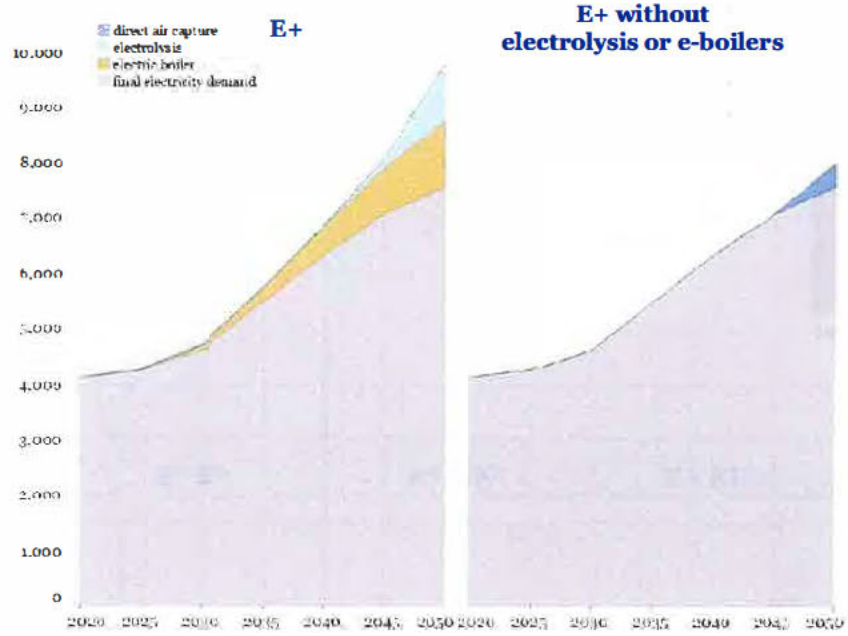
In a sensitivity case without large flexible loads, battery capacity increases, but other impacts are more significant

- Deployment of battery storage is relatively modest in E+, and increases by about 50% by 2050 if flexible electrolysis and industrial electric boilers are not available.
- When the flexible loads are disallowed, wind and solar generation are reduced and generation from gas with CO_2 capture increases.
- Direct air capture is deployed in the final time step (2046-2050) to offset emissions from greater use of natural gas combined cycle and combustion turbine power plants without CO_2 capture and gas use in other sectors.





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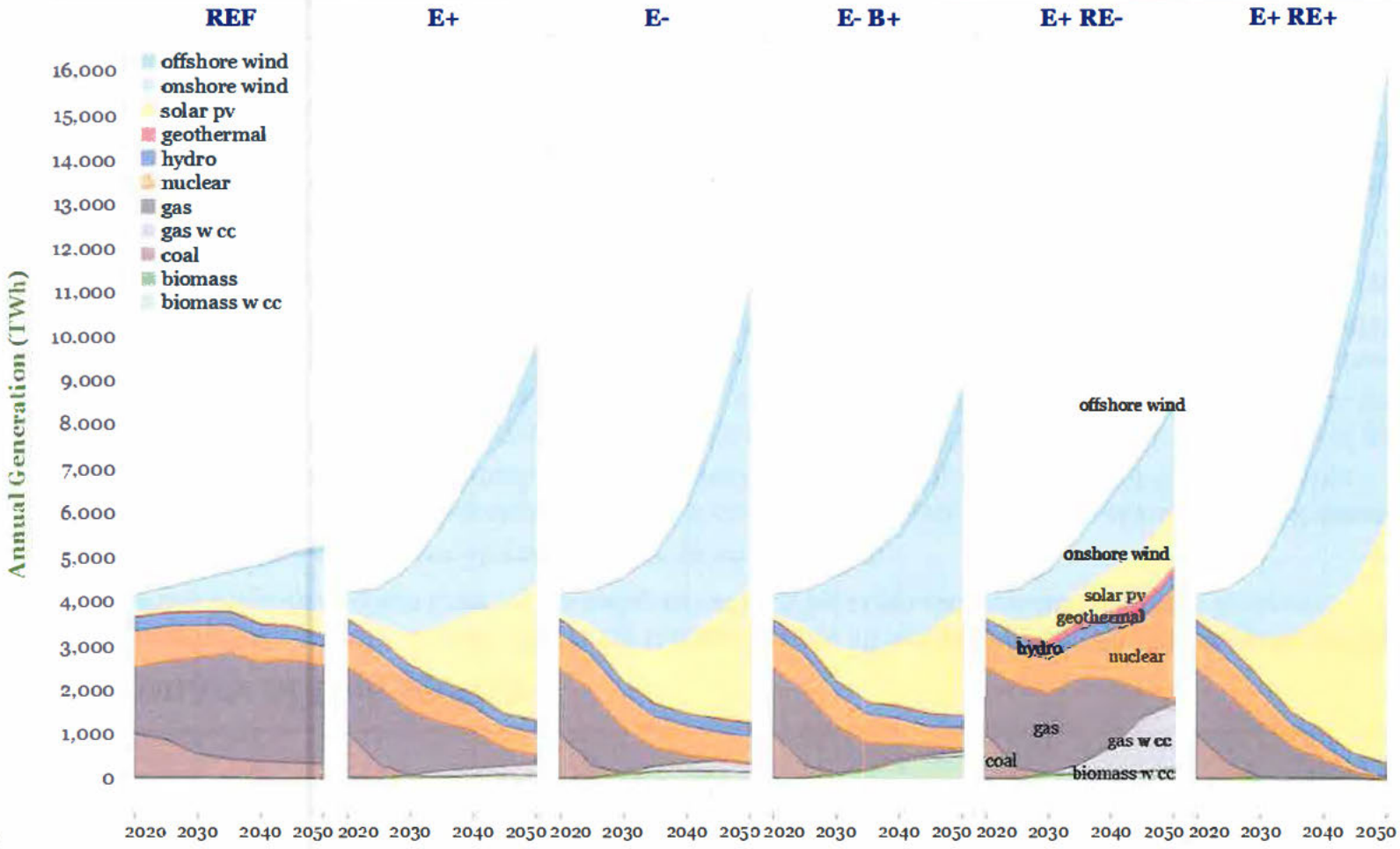
Pillar 2: Clean electricity



Summary of this section

- Expanding the supply of clean electricity is a linchpin in all net-zero paths. The share of electricity from carbon-free sources roughly doubles from ~37% today to 70-85% by 2030 and reaches 98-100% by 2050.
- Wind and solar power have dominant roles in all pathways:
  - Generation grows more than 4-fold by 2030 to supply about ½ of U.S. electricity in all cases except E+RE-; in that case, growth is constrained, but still triples by 2030 to supply one-third of U.S. electricity.
  - By 2050, they generate ~7,400-9,900 TWh of electricity in E+, E-, and E-B+ (~85-90% of generation). In E+RE-, ~3,700 TWh (44%); in E+RE+, 15,600 TWh (98%). (For context, all 2020 U.S. generation ~4,000 TWh)
  - Wind and solar capacity deployment rates set new records year after year (unless constrained in E+RE-), with extensive deployment across the United States (with corresponding visual, land use, and employment impacts).
- Nearly all coal-fired capacity retires by 2030 in all cases, reducing U.S. emissions by roughly 1 $GtCO_2$/year.
- Nuclear power plants are assumed to operate through 80 years whenever safe to do so.
- Natural gas generation declines, except in E+RE-, by 2-30% by 2030, while installed capacities are ±10% of the 2020 level. In E+RE-, gas-fired generation grows through 2035 (up 30% from 2020) before declining to just 7% of 2020 levels by 2050, even as total installed capacity grows to be 1/3 higher than in 2020.
- To ensure reliability, all cases maintain 700-1,100 GW of firm generating capacity through all years (compared to ~1,000 GW today); the model favors gas plants burning an increasing blend of hydrogen and with declining utilization rates through 2050. If wind and solar expansion is constrained, natural gas plants w/CO_2 capture and nuclear expand to pick up the slack.

Solar and wind generated electricity have dominant roles in all net-zero pathways



- Share of electricity from carbon-free sources roughly doubles from ~37% today to 70-85% by 2030 and reaches 98-100% by 2050.
- Wind + solar grows >4x by 2030 to supply ~½ of U.S. electricity in all cases except E+RE-; in that case, growth is constrained, but still triples by 2030 to supply ⅓ of electricity.
- By 2050, wind and solar supply ~85-90% of generation in E+, E-, and E-B+. In E+RE-, 44%; in E+RE+, 98%.

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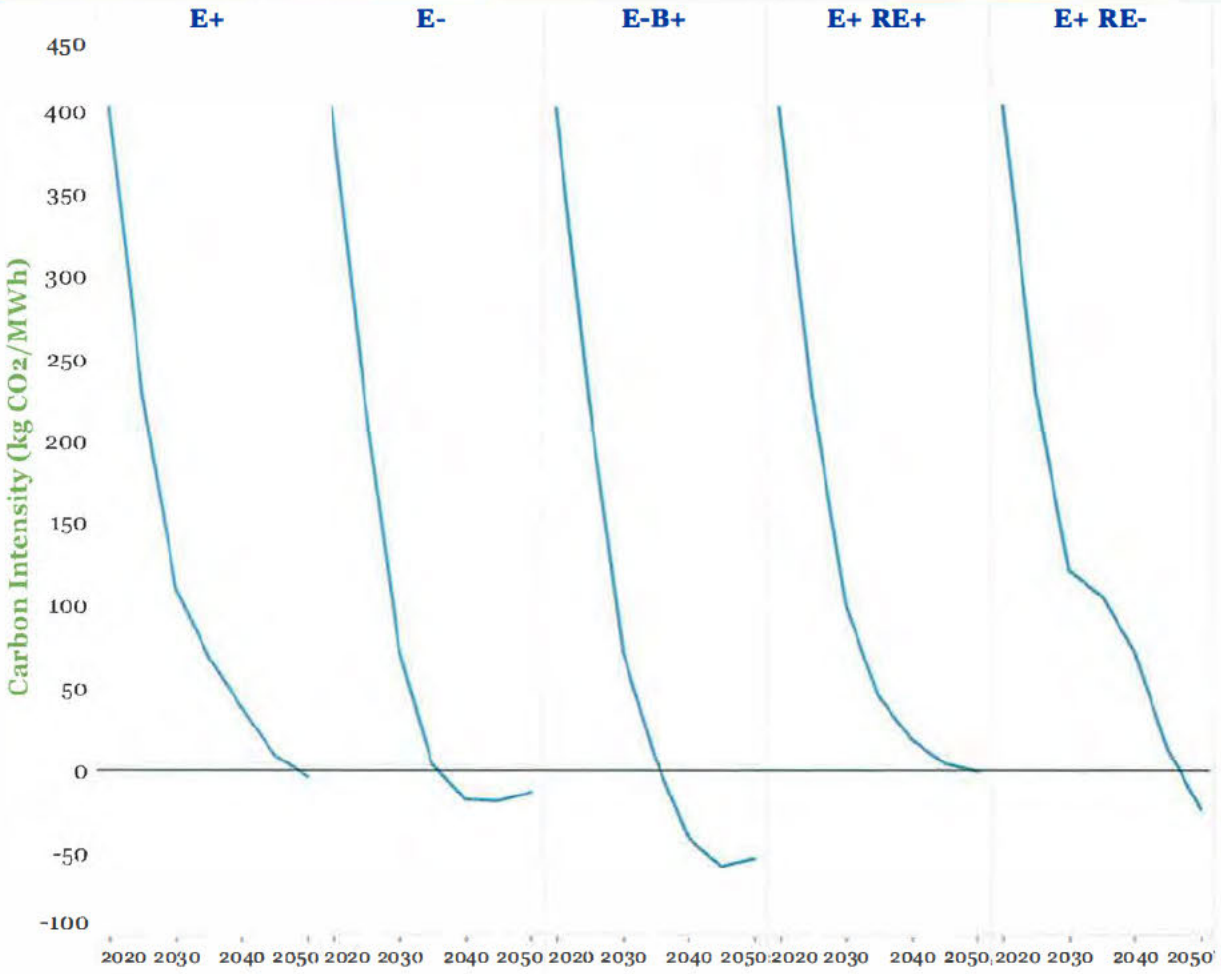
Carbon-intensity of electricity drops rapidly in all cases, reaching net-zero by 2035 in E- and negative values by 2050, except in RE+.



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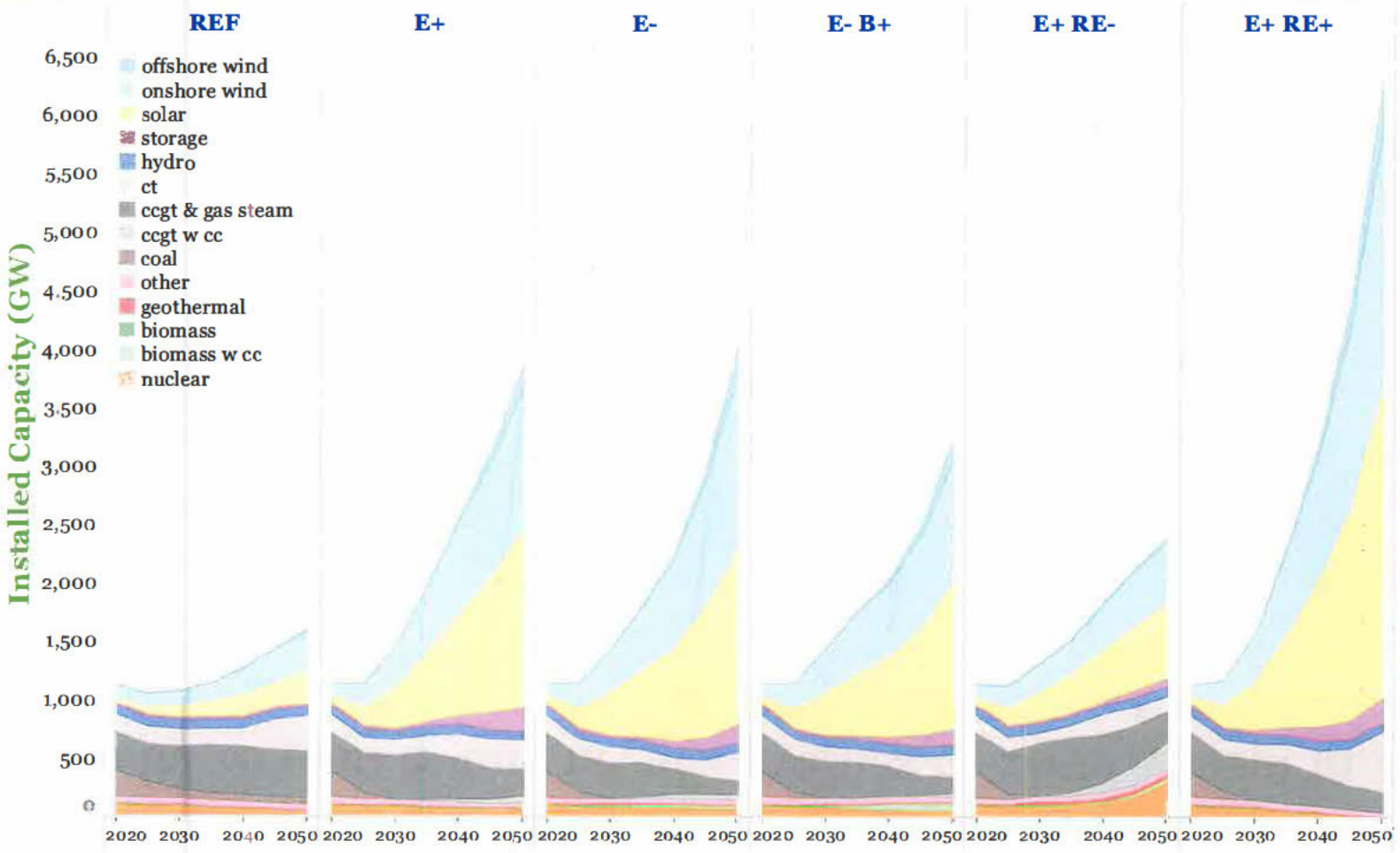
By 2050 installed solar capacity is 9 to 39 times larger than today, and installed wind capacity is 6 to 28 times larger.



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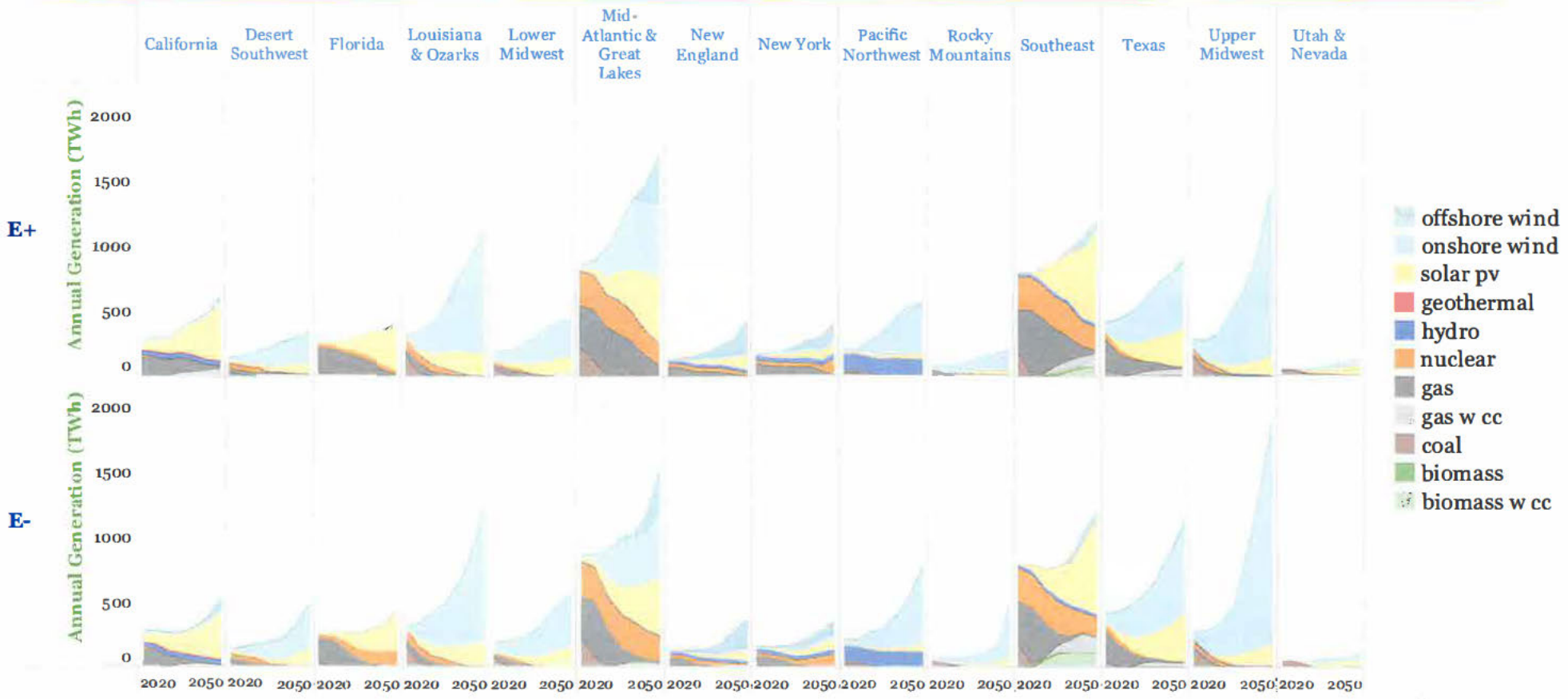
Regional evolution in electricity mix for E+ and E- scenarios.



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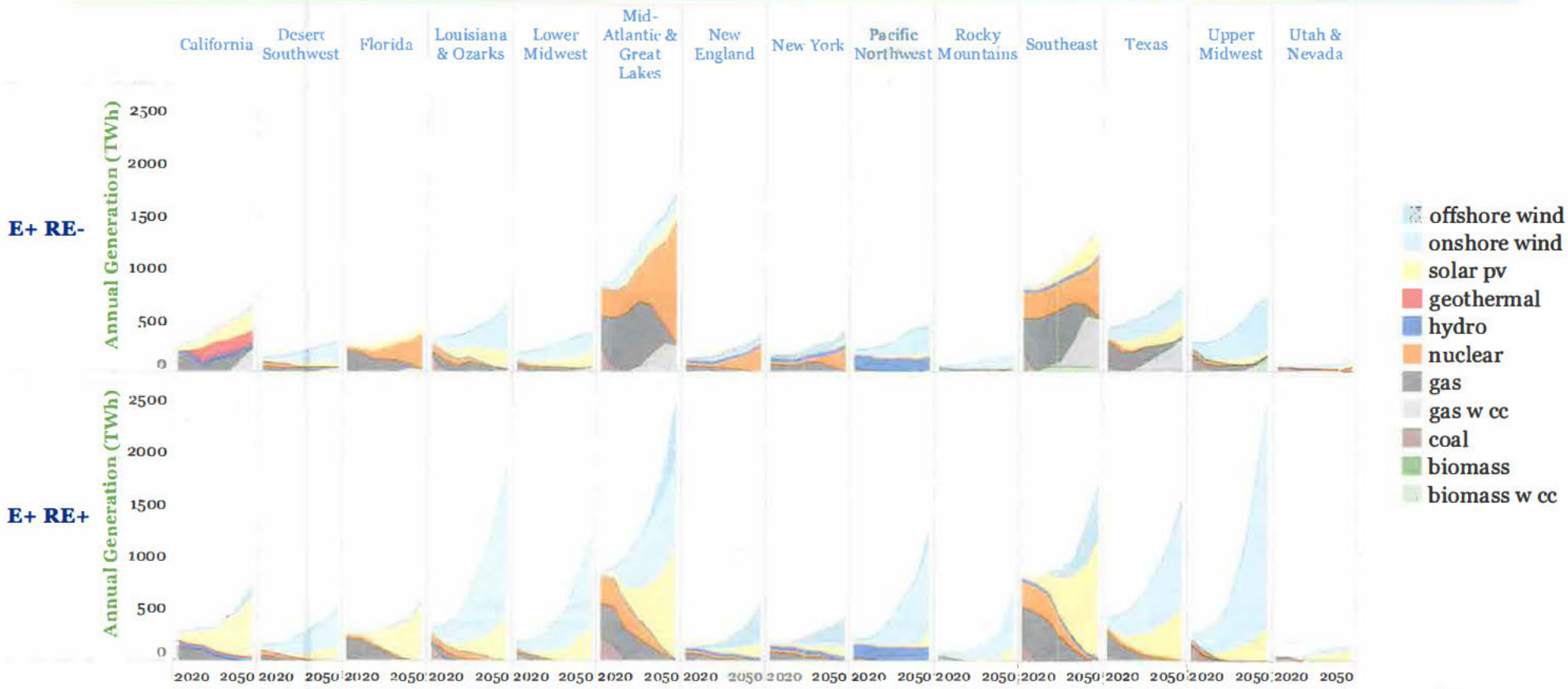
Regional evolution in electricity mix for RE- and RE+ scenarios.





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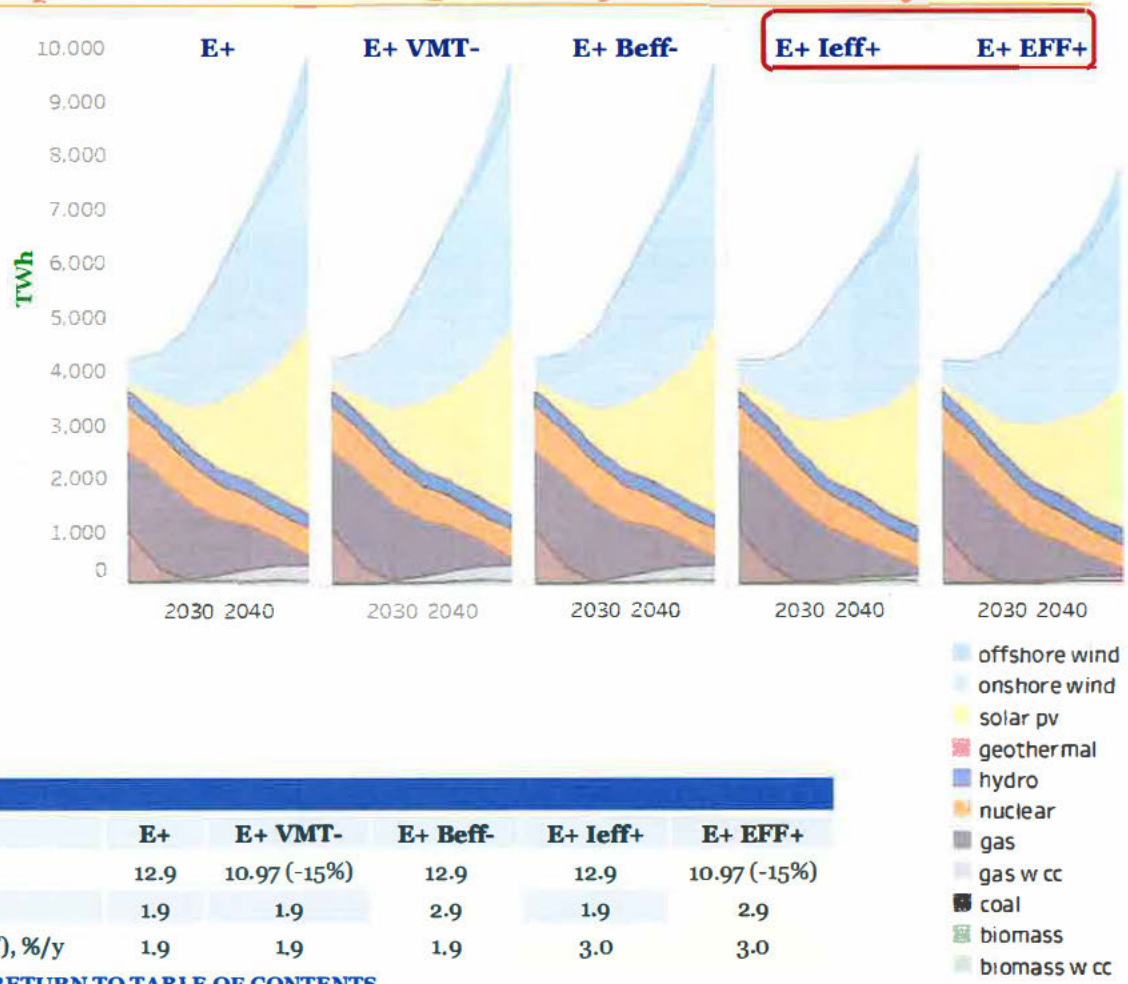
Solar and wind electricity generation in E+ would be reduced with further end-use efficiency improvements, especially in industry

E+ incorporates significant measures for end-use energy efficiency in all sectors, but more aggressive efficiency improvements were tested:

- Further efficiency gains in light-duty vehicles (or equivalent reduction in vehicle miles travelled, E+ VMT-) or building space conditioning (E+ Beff-) don't reduce electricity generation needs significantly, because the efficiencies for these electrified activities are already high.
- However, if industrial productivity improvement is higher (3%/year, the highest historically observed multi-decade rate, E+ Ieff+), wind and solar generation in 2050 would be reduced by over 10% relative to E+ and gas w/CC generation also falls; NPV of total energy-supply system cost declines ~5%.



Input assumptions that vary between cases

	E+	E+ VMT-	E+ Beff-	E+ Ieff+	E+ EFF+
Light duty vehicle-miles traveled in 2050, thousand VMT per vehicle	12.9	10.97 (-15%)	12.9	12.9	10.97 (-15%)
Buildings' heating/cooling final-energy demand reduction rate, %/yr	1.9	1.9	2.9	1.9	2.9
Industrial energy productivity ($ shipments/MJ) increase rate (vs. REF), %/y	1.9	1.9	1.9	3.0	3.0

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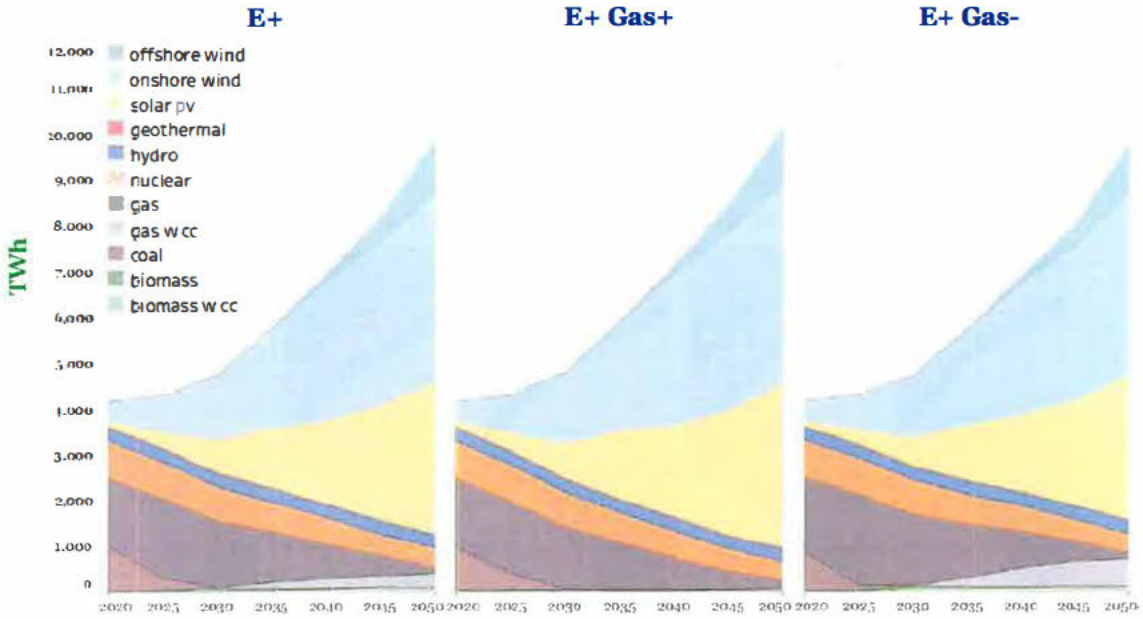
Power generation from natural gas with CO_2 capture plays a larger role if gas prices are lower

Natural gas prices in E+ are as projected in AEO2019 "High Oil and Gas Resource and Technology" scenario. With alternative gas price trajectories:

- With lower gas prices (E+ Gas-), electricity generation by NGCC w/CC increases at the expense of wind/solar and some nuclear. NPV of total energy-supply system cost from 2020 – 2050 (not shown here) is reduced by 2% relative to E+.
- With higher gas prices (E+ Gas+) gas w/CC generation is eliminated and replaced at greater than 1-to-1 by wind and solar due to greater electricity demands from flexible loads (e.g., electrolysis) to balance the added variable generation. NPV of total energy-supply system cost (2020 – 2050) increases ~2% relative to E+.



Input assumptions that vary between cases			
2016 $/GJ$_{HHV}$	E+	E+ Gas+	E+ Gas-
Natural gas price projection source	AEO2019 Hi oil/gas tech & resource	AEO2020 Lo oil&gas supply	AEO2020 Hi oil&gas supply
Natural gas price in 2020, 25, 30, 35, 40, 45, 50 (*)	2.5, 2.8, 3.0, 3.1, 3.1, 3.1, 3.3	2.5, 3.5, 4.4, 4.9, 5.2, 5.6, 6.2	2.3, 2.3, 2.5, 2.5, 2.5, 2.4, 2.4

* Natural gas price inputs vary between regions. The prices shown here are for the Texas region in the RIO model.

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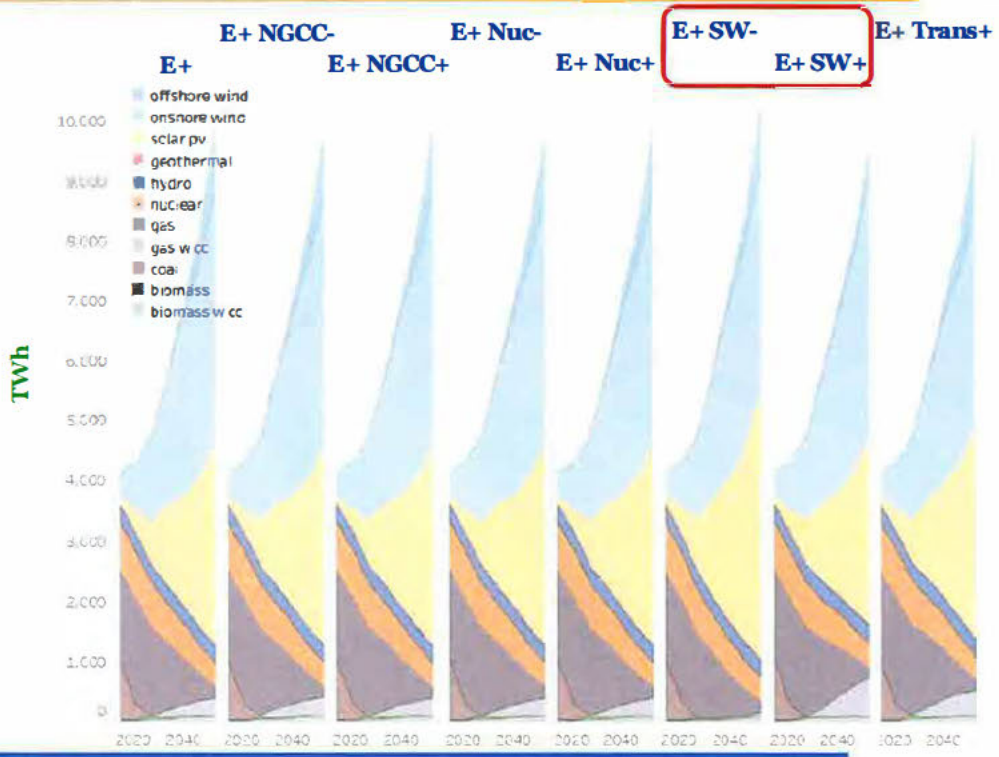
Higher or lower capital costs for solar and wind mostly impact the balance between NGCC w/CC and solar/wind generation

Future capital costs for power sector technologies are uncertain. E+ was tested with higher and lower power-sector capital cost assumptions:

- Changes in solar/wind capital costs have the largest impacts due to the large installed capacity:
  - Lower costs lead to more wind/solar and less NGCC w/CC. NPV of total energy-supply system (2020 – 2050) is ~2% lower than for E+.
  - Higher costs drive more NGCC w/CC into the generating mix.
- Higher transmission costs have a similar impact as higher solar/wind costs.
- Lower or higher costs for natural gas w/CC or for nuclear have little impact because firm capacity needs remain consistent and gas w/CC retains advantage over nuclear at all of these cost combinations (given low natural gas prices).



Input assumptions that vary between cases

$/kW in 2050	E+	E+ SW -/+	E+ NGCC -/+	E+ Nuc -/+	E+ Trans+
NGCC w/CC (+50% / -20%)	1,725	1,725	1,380 / 2,589	1,725	1,725
Nuclear (+50% / -20%)	5,530	5,530	5,530	4,423 / 8,295	5,530
Solar/wind (TRG1 NJ, e.g.)*	PV: 869 / Wind: 1,723	PV: 453; 1,144 / Wind: 1,433; 2,280	PV: 869 / Wind: 1,723	PV: 869 / Wind: 1,723	PV: 869 / Wind: 1,723
Trans. (Mid-Atl → NY, e.g.)	2,821	2,821	2,821	2,821	5,642

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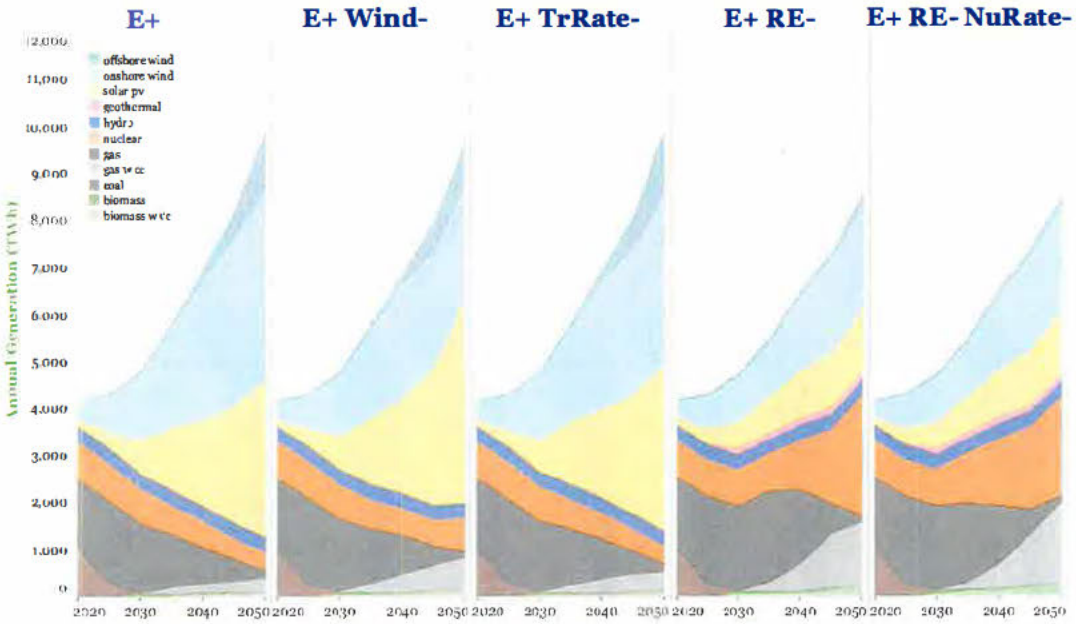
* E+ uses NREL Annual Technology Baseline (ATB2019) mid-range cost projections. For SW- and SW+, ATB2019 low-cost and average of mid- and constant-cost projections are used, respectively.

Constrained nuclear deployment rate in E+ RE- will significantly increase the use of gas w CC, but has small impact on E+ scenario

Siting or supply chain constraints may slow the rate of plant and infrastructure deployment. We tested constraints on cumulative wind and transmission capacity and the rate of new nuclear capacity build:

- For E+, limiting inter-regional transmission capacity to a maximum of 2x current capacity (E+ TrRate-) leads to slightly more gas w/CC and less wind
- Limiting total wind capacity (E+ Wind-) results in more solar and gas w/CC and also spurs deployment of new nuclear capacity in the 2040s.
- For E+RE-, limiting the rate of nuclear capacity expansion (E+ RE- NuRate-) leads to about 40% less new nuclear capacity built over the 30-year period and also delays the need for significant gas w/CC capacity until the 2040s. The NPV of the total energy-supply system (2020 – 2050) is not significantly affected.



Input assumptions that vary between cases	E+	E+ Wind-	E+ TrRate-	E+ RE-	E+ RE- NuRate-
Wind total capacity limit (% of E+ capacity)	None	Onshore 50%; Offshore: 100% (except Mid-Atlantic: 70%)	None	None	None
Nuclear build-rate cap	None	10 GW/y	None	None	10 GW/y
Transmission cumulative build cap	10x current	10x current	2x current	10x current	10x current

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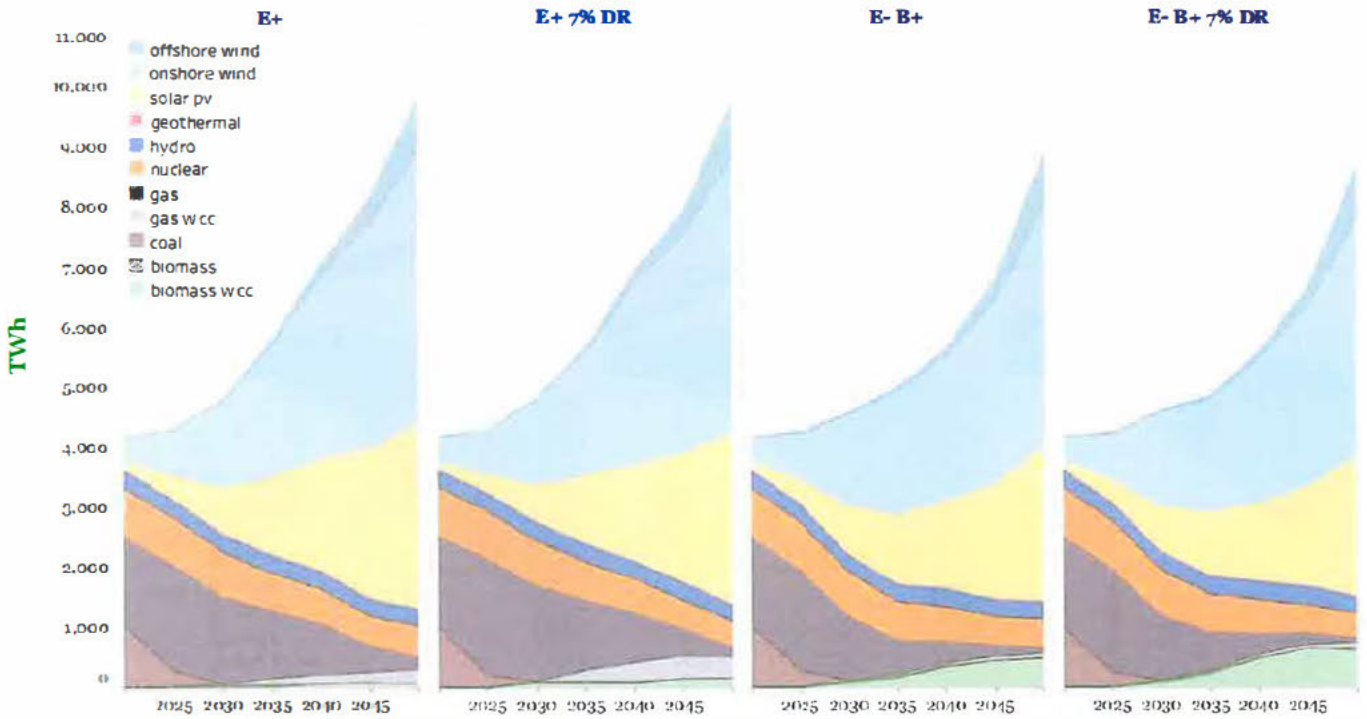
Higher discount rate dramatically reduces the NPV of total energy-system costs, but has no substantial impact on the generating mix

Use of 7% social discount rate instead of 2% results in:

- Only a small increase in deployment of capital-intensive generators (NGCC w/CC or biopower w/CC) late in the modeling period.
- NPV of total energy-supply system cost (2020 – 2050) being reduced by roughly half due to higher discounting of future costs.



Input assumptions that vary between cases	E+	E+ 7%	E- B+	E- B+ 7%
Social discount rate	2%/y	7%/y	2%/y	7%/y

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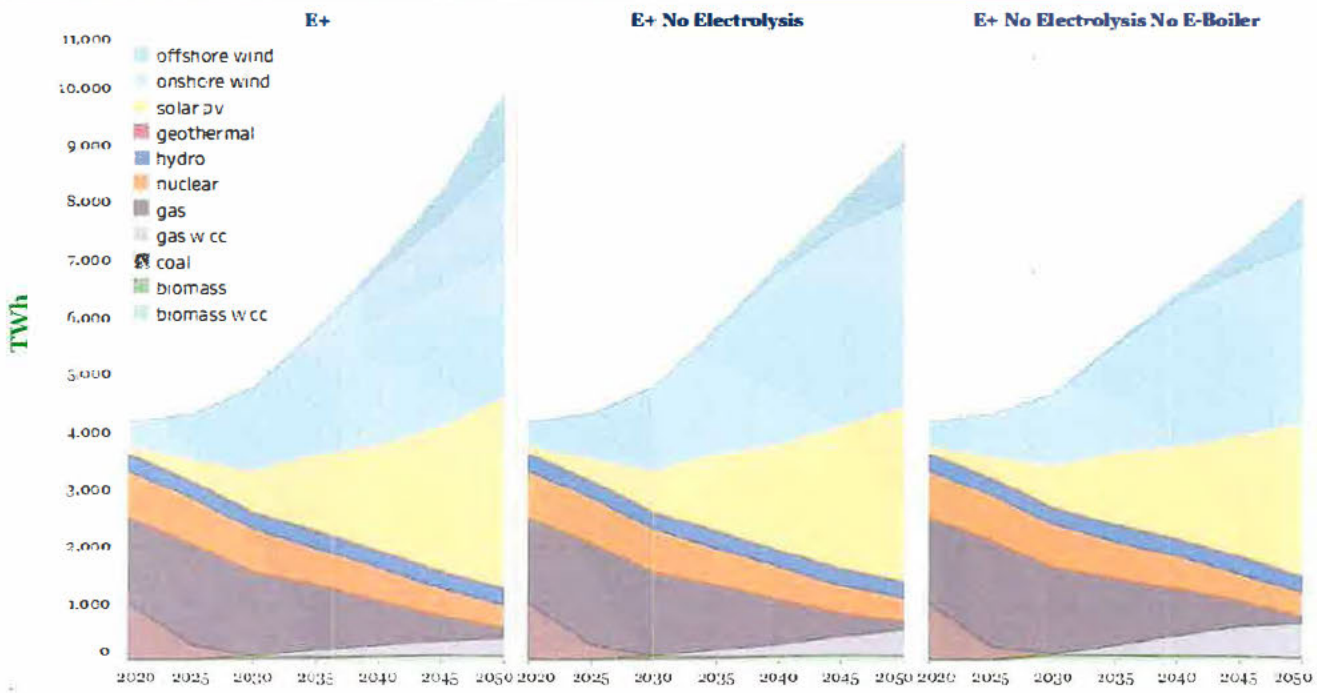
Availability of electrolysis and electric boilers supports larger build out of solar and wind generation

Electrolysis and electric boilers are important flexible loads:

- For E+ without an electrolysis option, the electricity system that minimizes overall energy system cost has less solar and wind generation, but slightly more gas with CC by 2050. NPV of total energy-supply system cost (2020 – 2050) does not change appreciably from E+.
- With neither electrolysis nor electric boiler options available, solar and wind generation decrease further, and gas with CC increases further. NPV of total energy-supply system increases by a small amount.



Input assumptions that vary between cases			
	E+	E+ No Electrolysis	E+ No Electrolysis No E-boiler
Electrolysis technology available?	Yes	No	No
E-Boiler technology available?	Yes	Yes	No

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Evolution of solar and wind generating capacity

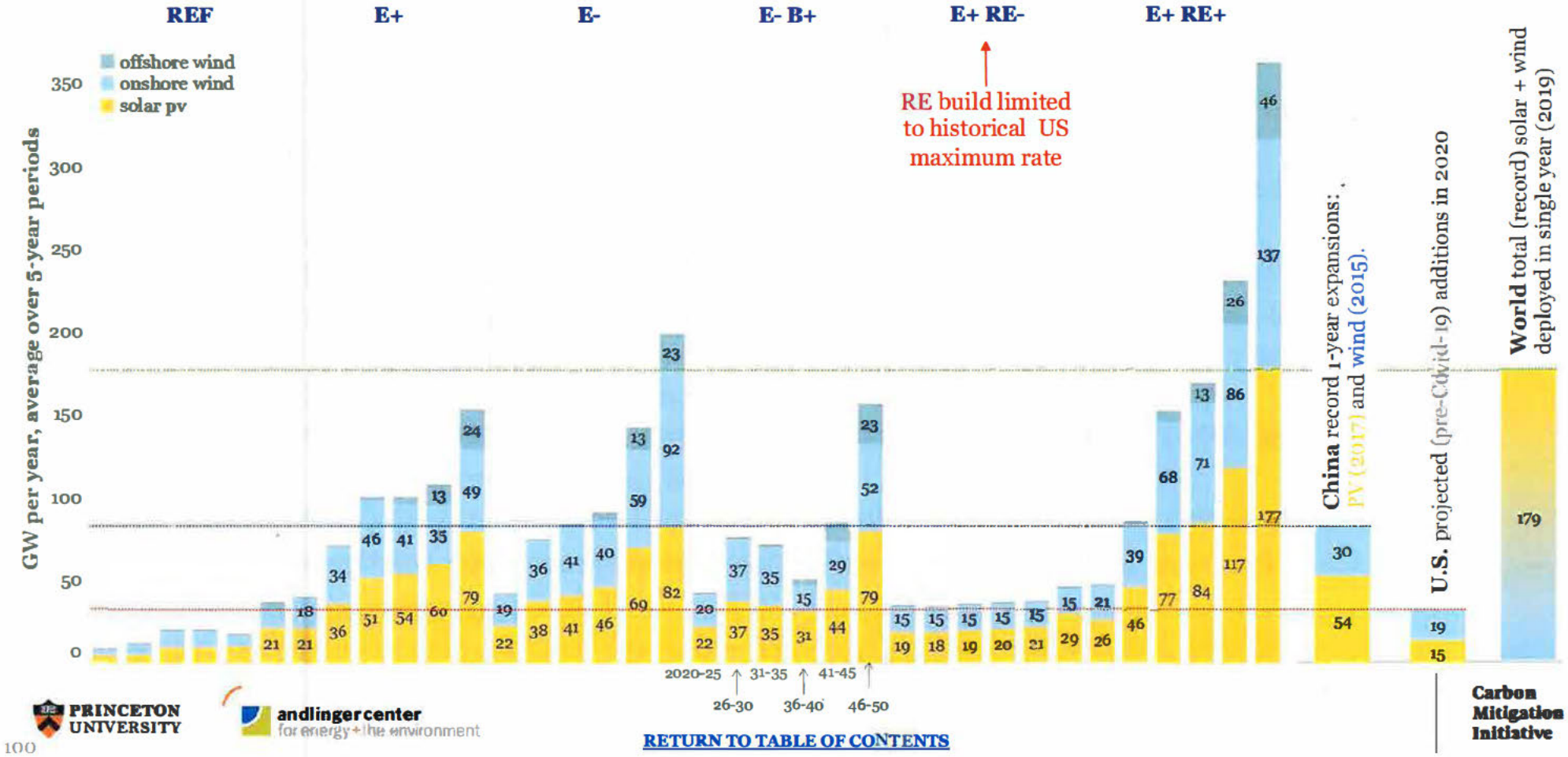


Summary of this section

- Wind and solar capacity additions accelerate, setting new record deployment rates year after year.
  - The only exception is E+RE- where capacity additions are limited by the scenario design to historical maximum rates (~35 GW/year)
- Deployment rates in the 2021-2025 period are close to U.S. record maximums (~40 GW/year average); this rate nearly doubles to 70-75 GW/year average from 2026-2030.
  - A total of ~250-280 GW of new wind (~2.5-3x current capacity) and ~285-300 GW of new utility-scale solar (~4x current capacity) is installed from 2021-2030 in E+, E- and E-B+ pathways.
  - E+ RE+ deploys 290 GW of wind and 360 GW of solar; E+RE- installs 150 GW of wind and 185 GW of solar from 2021-2030.
- By the 2030s, most cases are deploying more wind and solar than the world record for a single nation (set by China).
- E- and E+ RE+ eventually reach annual deployment rates in the late 2040s exceeding the total global wind and solar capacity added in 2019 (>180 GW/year).

Annual wind and solar capacity additions are sustained over multiple decades at historically-unprecedented rates





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Carbon Mitigation Initiative

Downscaling methodology for solar and wind and transmission siting in net-zero pathways



Summary of this section

- Wind and solar capacity is deployed extensively across the United States in all cases.
- Finding sites suitable to develop projects presents a potential bottleneck to wind and solar deployment.
- To assess availability of lands for wind and solar development, we conduct a high resolution (4km x 4km) evaluation of the entire continental U.S. (and offshore wind development areas) using ~50 total geospatial screens to exclude areas with potentially conflicting land uses, including high population density areas, protected lands (e.g. parks, wilderness), the most productive farm lands, or areas with high environmental conservation value, as well as areas unsuitable for construction (e.g. wetlands, mountain slopes).
- To visualize the extent of wind and solar deployment and supporting transmission expansion over time, we downscale RIO's coarse-resolution model results (14-regions for continental U.S.)
- Individual "candidate project areas" that pass the land use screening process are selected to supply sufficient capacity in each model region and to minimize the total cost of project sites (including grid connection).
- We also visualize a notional expansion of transmission capacity required to connect wind and solar project sites to demand centers (e.g. major metropolitan areas).
- These downscaling results represent one of many possible configurations of wind, solar, and transmission siting decisions, guided by a least-cost siting algorithm; other configurations may minimize land use conflict and/or maximize local benefits.

Candidate solar and onshore wind project sites mapped for "Base" and "Constrained" land availability.

Methodology similar to Wu, *et al.*, *Power of Place: Land Conservation and Clean Energy Pathways for California*, The Nature Conservancy, 2019.

* Exclusion categories that distinguish Base from Constrained land availability are shown in red.

Constrained scenarios are designed to limit development on intact landscapes. Theobald's HMI is used to quantify intactness. HMI is derived from analysis of North America at 0.09 km² resolution, with each cell assigned a value from 0 to 1 based on multiple metrics. HMI values < 0.082 identify highly intact landscapes.

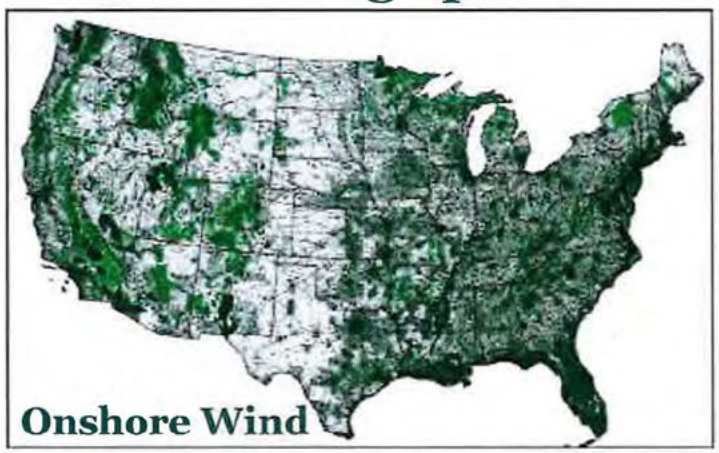
Constrained scenarios also restrict onshore wind development on prime farmlands (this is permitted in Base).

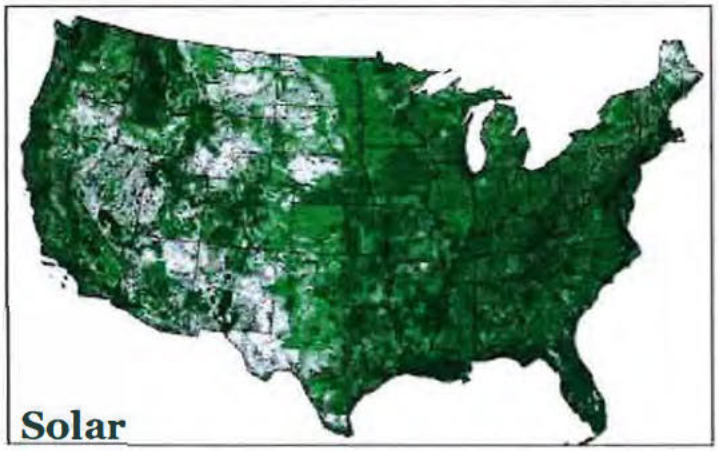
	Solar	Onshore Wind
NREL capacity factor map resolution, km	10	2
Average power density (MW/km²)	45	2.7
Land areas excluded from siting of wind / solar projects		
Slope	> 17%	> 34%
Intactness: Theobald Human Modification index*	HMI < 0.082 for CONSTRAINED only	
Population density	> 100 people/km² excluded; density of solar/wind projects in other areas is restricted in inverse proportion to population density	
Urban areas + buffer, km	0.5	1
Water bodies + buffer, km	0.25	0.25
Military installations + buffer, km	1	3
Active mines + buffer, km	1	1
Airports and runways + buffer, km	1	3
Railways + buffer, km	0.25	0.25
Prime soils (prime farmland)	Not allowed	Allowed in BASE. Not allowed in CONSTRAINED
FEMA 1% annual flood hazard areas	Not allowed	
Areas of critical environmental concern	Not allowed	
National forests (except for wind on ridgecrests), parks, wilderness, recreation, and other federal protected areas	Not allowed	
State parks, forests, wilderness & other protected areas	Not allowed	
Wetlands and watershed protected areas	Not allowed	
Private conservation & forest stewardship areas	Not allowed, except for wind on ridge crests	
Native American areas	Not allowed	
BLM *High* and *Moderate* sensitivity areas	Not allowed	

~50 total environmental, cultural, and economic exclusions. See full list here

Current land uses limit where solar and wind projects can be built.

Base siting options





Shaded regions are excluded from development.

Unshaded regions are suitable for siting projects (candidate project areas)

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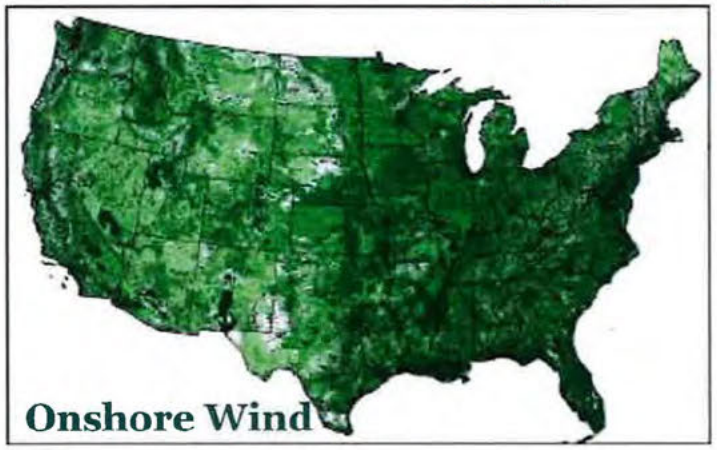
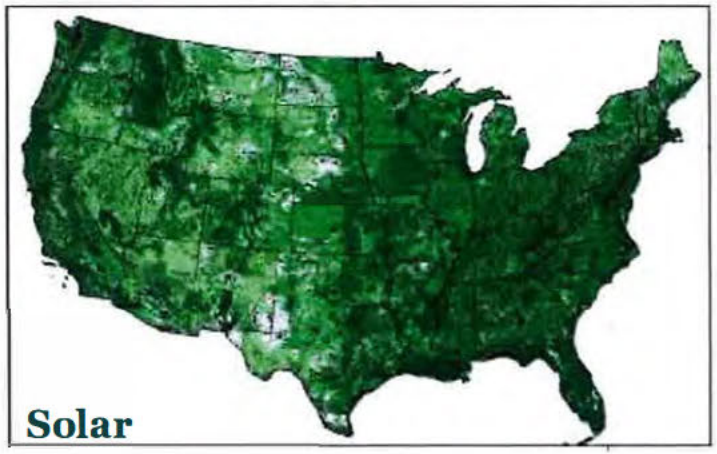
Constrained siting options





Offshore wind exclusion areas and capacity siting process



Exclusion areas

- Shipping lanes
- Marine protected areas
- Gap status 1 for West, Gulf, and East coasts; Gap status 2 for West and Gulf coasts only (gap status relates to level of sensitivity/administrative protection)
- Military installations + 3 km buffer
- Military danger zones + 3 km buffer
- Outside BOEM-designated zones, candidate area further reduced by 40% (at random) to account for uncertainty about additional exclusions not explicitly geo-specified
- Areas closer than 30 km to shore or greater than 100 km from shore (similar to current BOEM lease zones)

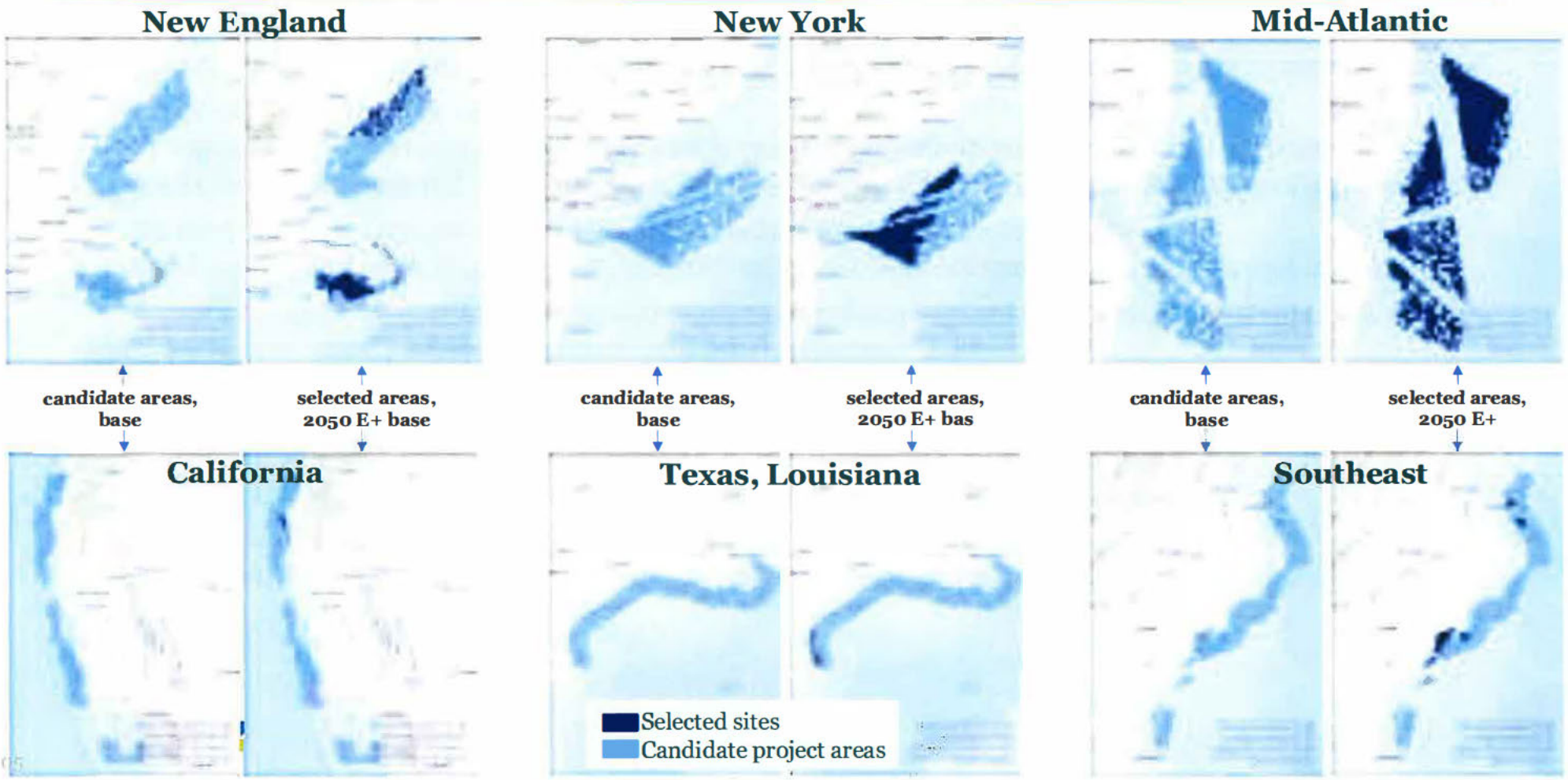
Wind farm technical characteristics

- Power density: West coast, 8 MW/km² (floating turbines, seafloor depth > 50 m); East & Gulf coasts: 5 MW/km² (fixed turbines, most areas have depth < 50m).
- Capacity factors at 13-km spatial resolution from Vibrant Clean Energy

Sites selected for farms by lowest approximate LCOE until total supply fulfilled

- Turbine capex (avg for 2021-2050 used for ordinal ranking): $3,105/kW (sea depth < 50m); $4,519/kW (> 50 m) (NREL, ATB2019 mid)
- Sub-sea transmission: $20,500/MW-km (< 50m); $28,300/MW-km (> 50m) (ATB2019 mid)

Offshore-wind candidate project areas and selected sites for E+, with base siting constraints



Mapping solar and wind generators and transmission for the E+ pathway with Base land availability



Summary of this section

- In E+, about 300 GW of wind and 300 GW of solar are built across the U.S. by 2030; ~1.5 TW each of wind and solar capacity are deployed by 2050;
- Following a least-cost siting method subject to the Base land availability screen:
  - The top 10 states for wind capacity by 2050 are: Texas, Missouri, Iowa, Illinois, Nebraska, Minnesota, New Mexico, Montana, Oklahoma, and Arkansas
  - The top 10 states for solar capacity by 2050 are: California, Texas, Florida, Georgia, Pennsylvania, South Carolina, Virginia, Alabama, Missouri, Nebraska
  - About $700 billion is invested in wind and solar capacity through 2030 and $3.2 trillion by 2050.
- Onshore wind and solar farms span a total area of nearly 600,000 km²; wind farms make up ~93% of total land area and may have extensive visual impact on nearby communities.
- Lands directly impacted by wind and solar farms (e.g. with roads, turbine pads, solar arrays, inverters, and substations) are only a fraction of the total site area: about 40,000 km², with solar farms accounting for about 85% of this.
- High voltage transmission capacity expands ~60% by 2030 and triples through 2050 to connect wind and solar facilities to demand; total capital invested in transmission is $360 billion through 2030 and $2.4 trillion by 2050.

Evolution of wind and utility-scale solar projects, E+ Base



As of end 2020 (modeled year)	Wind	Solar
Capacity installed (TW)	0.15	0.07
Land used (1000 km²)		
Total	58	1.08
Direct	0.6	0.97

Note: Site capacity factors are reflected in color intensity (highest CF = darkest color).

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Evolution of wind and utility-scale solar projects, E+ Base



2020 - 2025 (cumulative)	Wind	Solar
Capacity installed (TW)	0.21	0.15
Land used (1000 km²)		
Total	82	3.3
Direct	0.8	3.0
Capital invested (2018$)		
Trillion $	0.10	0.10

Note: Site capacity factors are reflected in color intensity (highest CF = darkest color).

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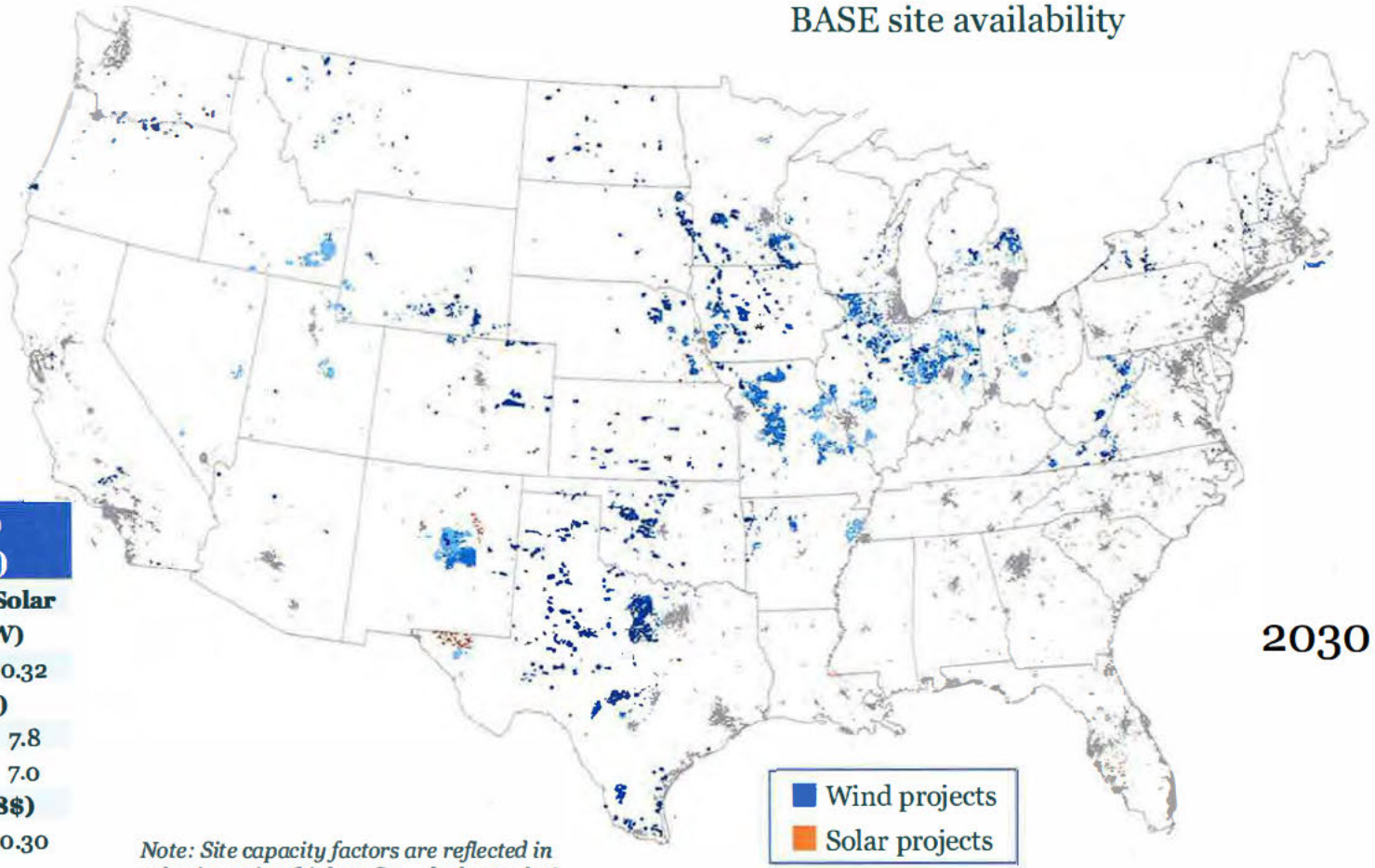
Evolution of wind and utility-scale solar projects, E+ Base



2030

2020 - 2030 (cumulative)	Wind	Solar
Capacity installed (TW)		
	0.41	0.32
Land used (1000 km²)		
Total	157	7.8
Direct	1.6	7.0
Capital invested (2018$)		
Trillion $	0.37	0.30

Note: Site capacity factors are reflected in color intensity (highest CF = darkest color).

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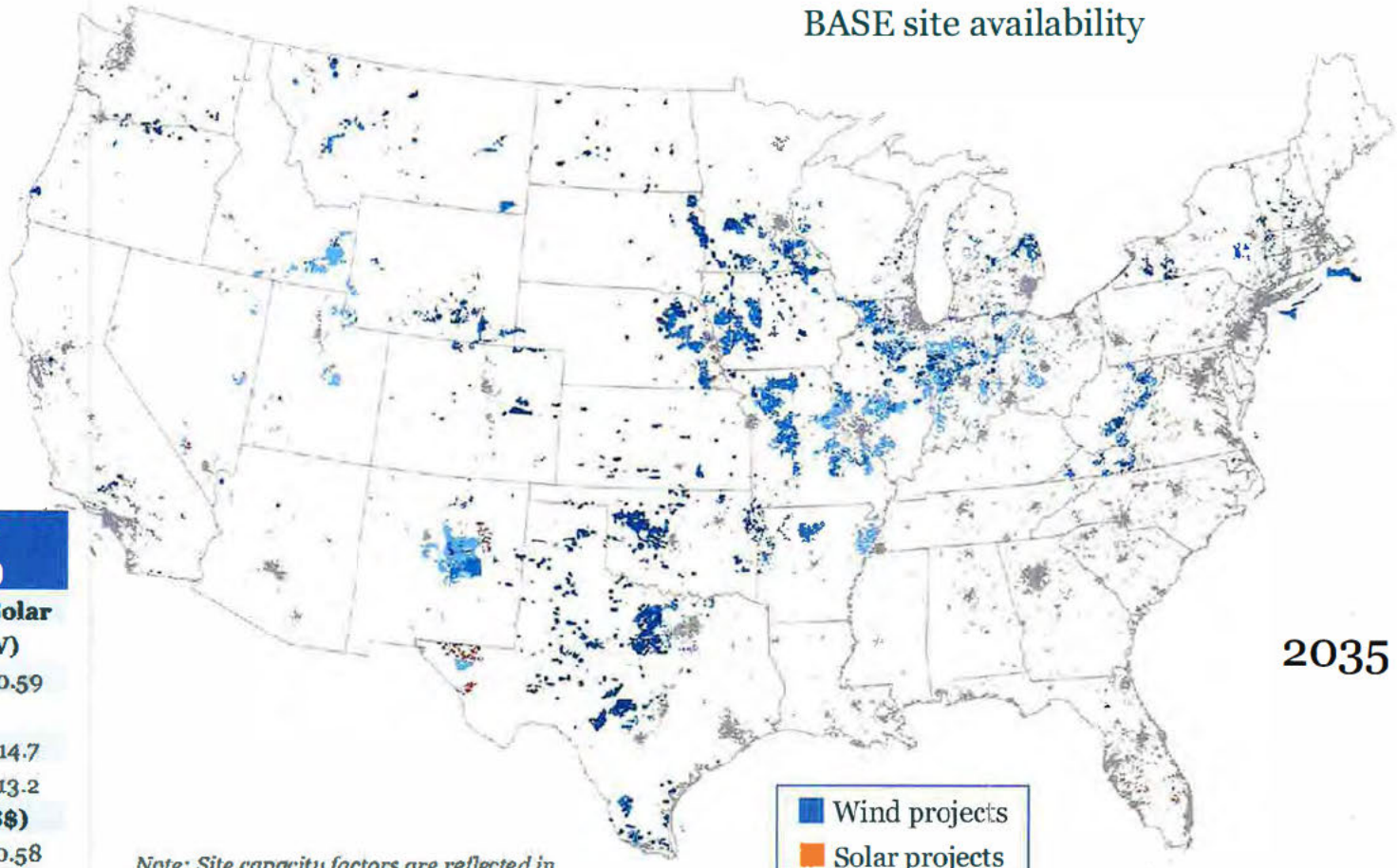
Evolution of wind and utility-scale solar projects, E+ Base



Note: Site capacity factors are reflected in color intensity (highest CF = darkest color).

2020 - 2035 (cumulative)	Wind	Solar
Capacity installed (TW)		
	0.65	0.59
Land used (km²)		
Total	245	14.7
Direct	2.5	13.2
Capital invested (2018$)		
Trillion $	0.69	0.58

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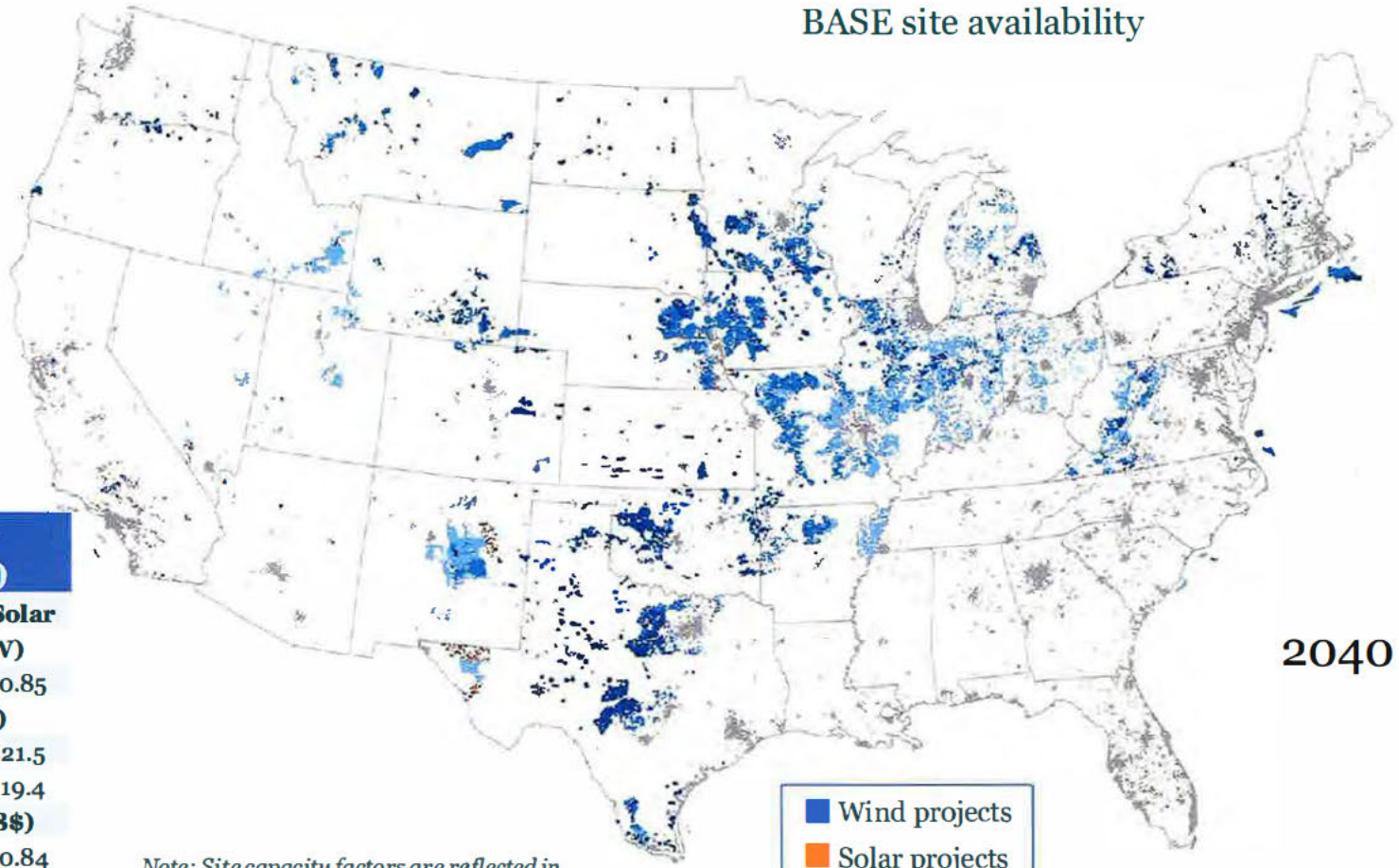
Evolution of wind and utility-scale solar projects, E+ Base



BASE site availability



2040

2020 - 2040 (cumulative)	Wind	Solar
Capacity installed (TW)		
	0.95	0.85
Land used (1000 km²)		
Total	355	21.5
Direct	3.6	19.4
Capital invested (2018$)		
Trillion $	1.07	0.84

Note: Site capacity factors are reflected in color intensity (highest CF = darkest color).

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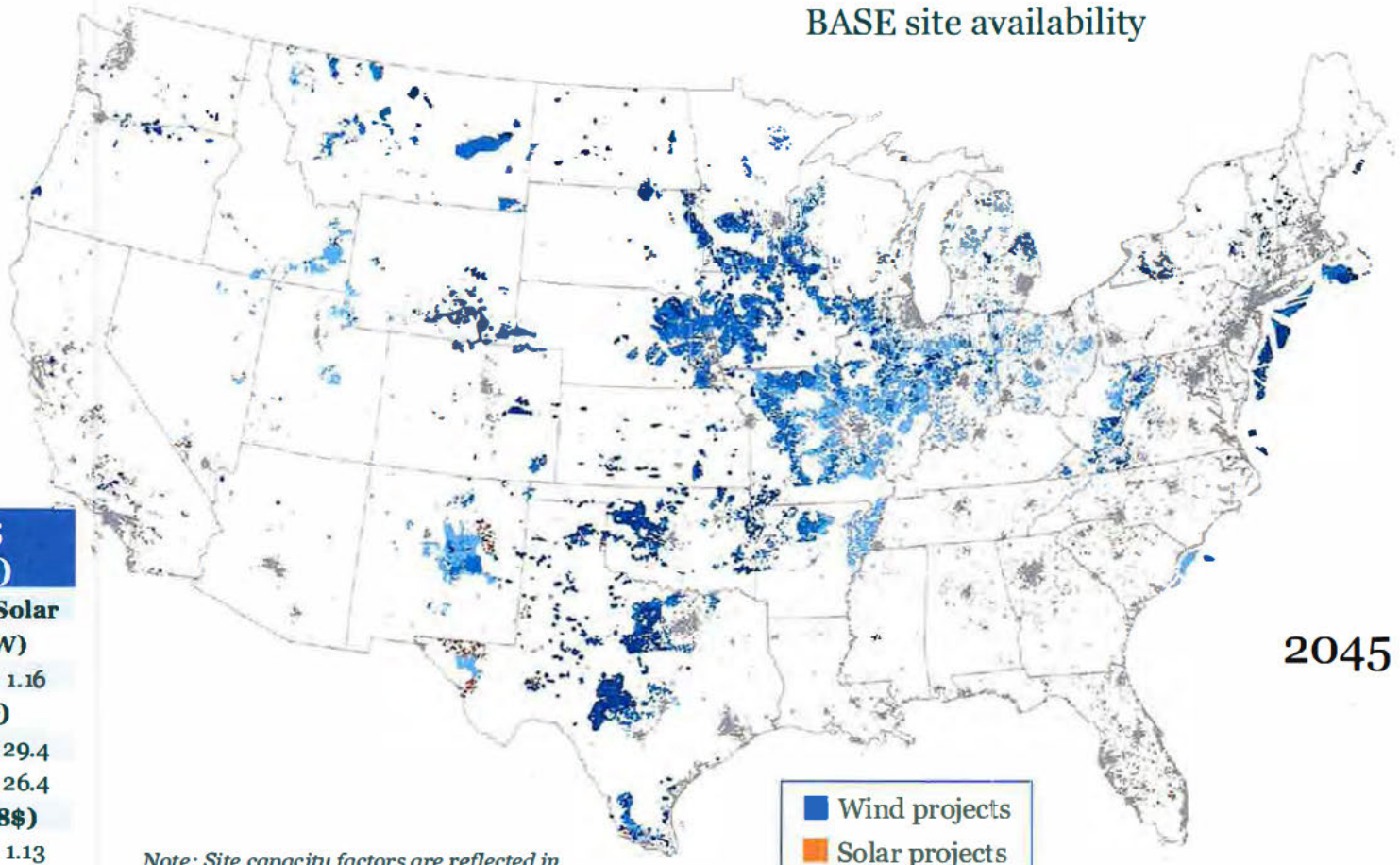
Evolution of wind and utility-scale solar projects, E+ Base



2020 - 2045 (cumulative)	Wind	Solar
Capacity installed (TW)	1.20	1.16
Land used (1000 km²)		
Total	46	29.4
Direct	4.5	26.4
Capital invested (2018$)		
Trillion $	1.44	1.13

Note: Site capacity factors are reflected in color intensity (highest CF = darkest color).

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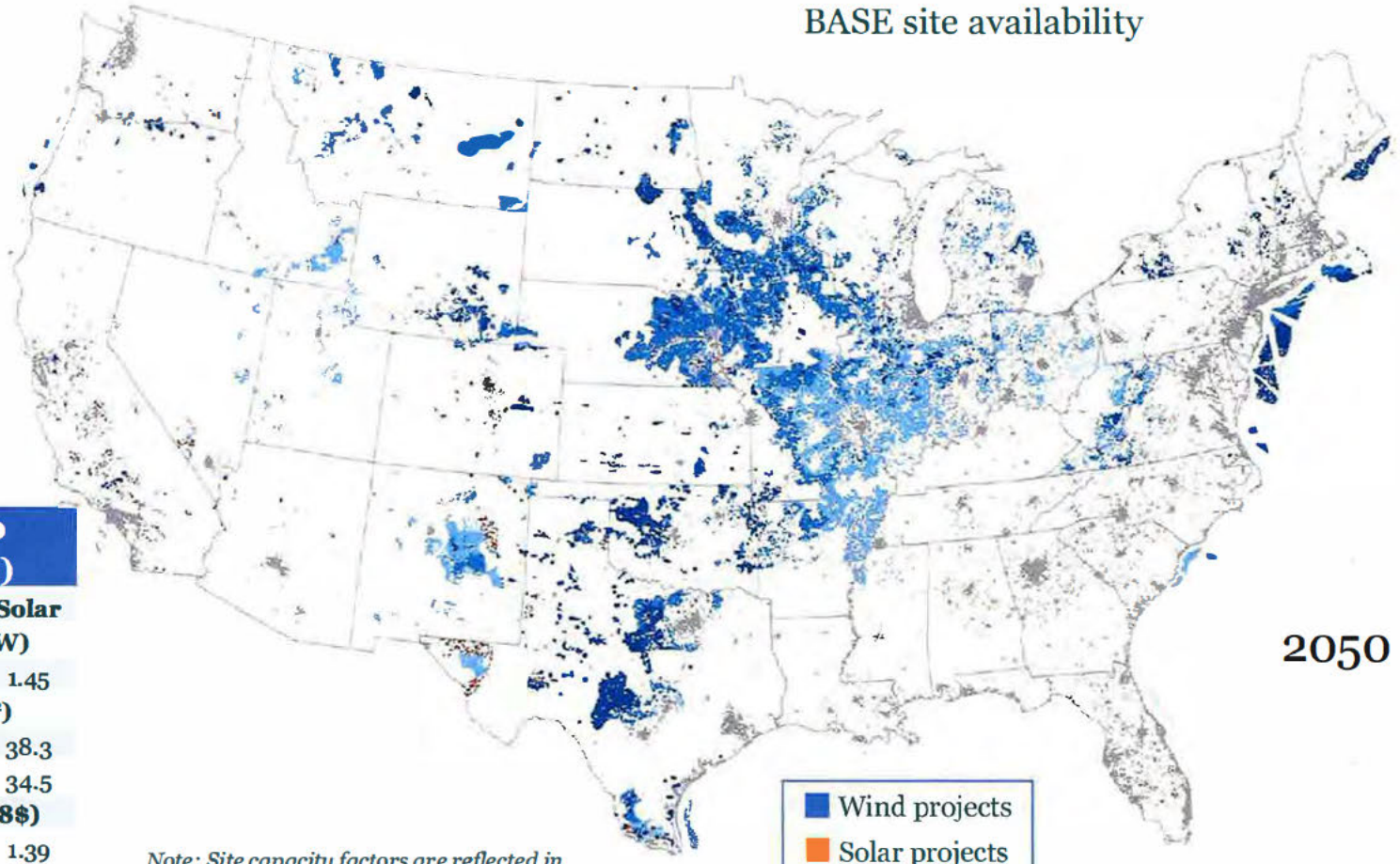
Evolution of wind and utility-scale solar projects, E+ Base



2020 - 2050 (cumulative)	Wind	Solar
Capacity installed (TW)		
	1.48	1.45
Land used (1000 km²)		
Total	550	38.3
Direct	5.5	34.5
Capital invested (2018$)		
Trillion $	1.84	1.39

Note: Site capacity factors are reflected in color intensity (highest CF = darkest color).

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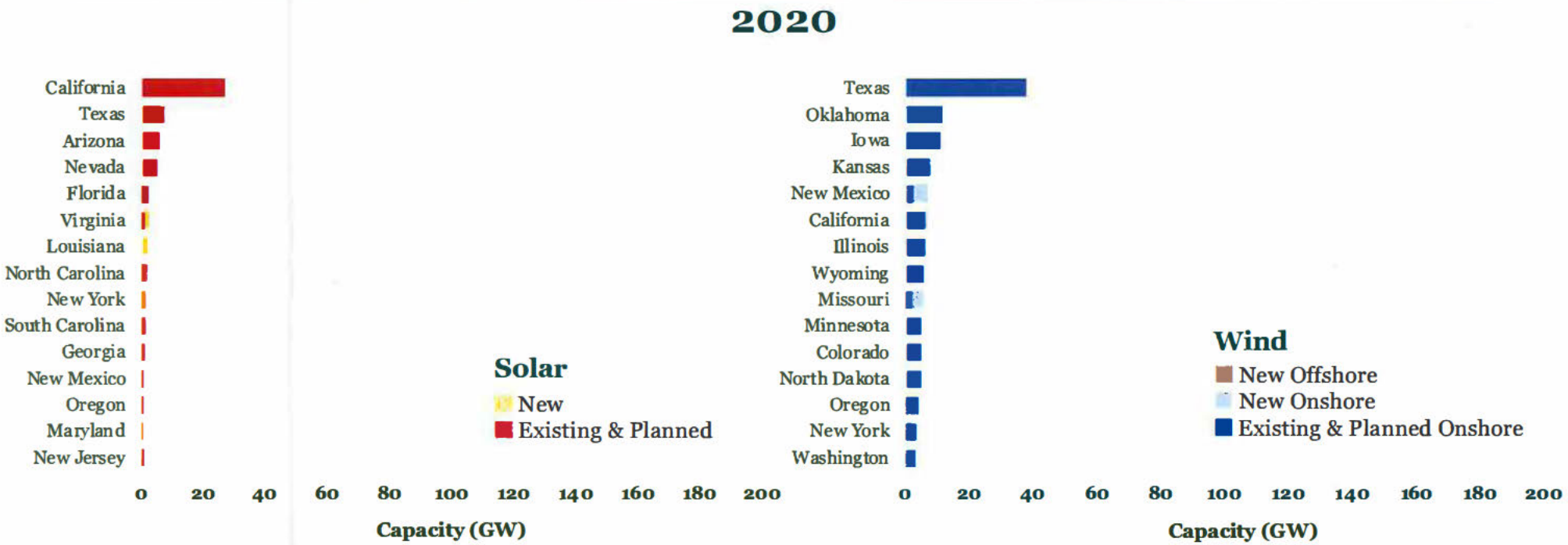
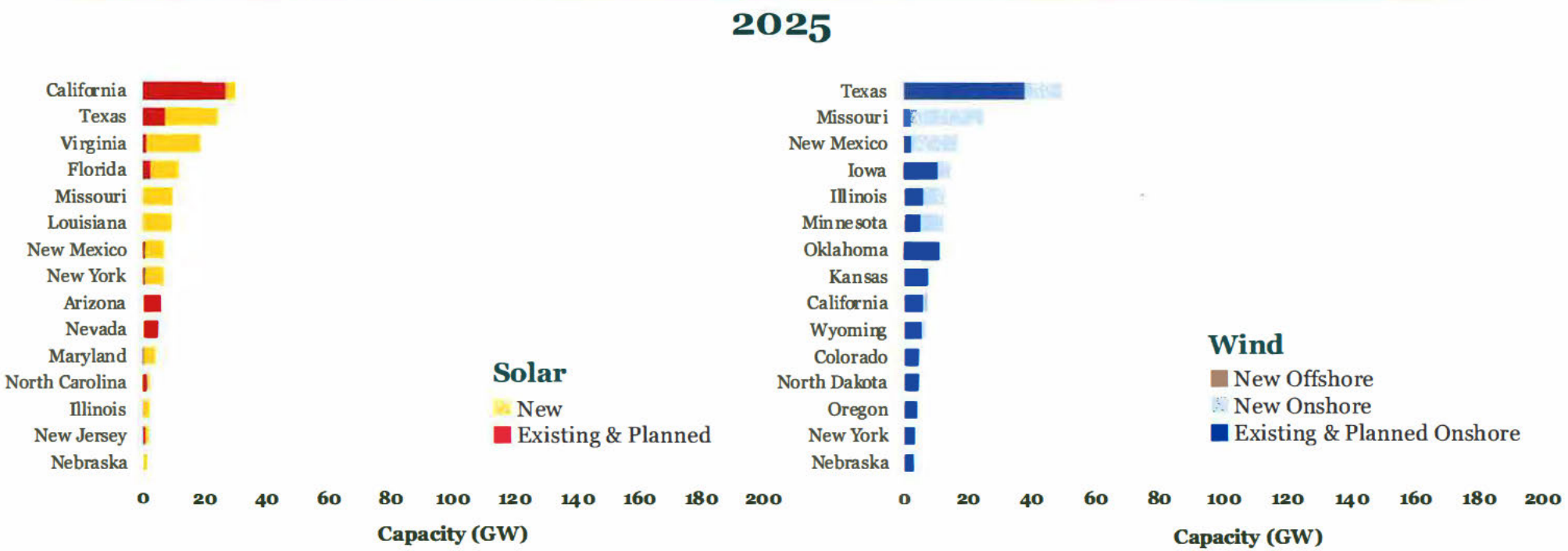
Installed solar and wind capacity, top-ranked states, E+ Base





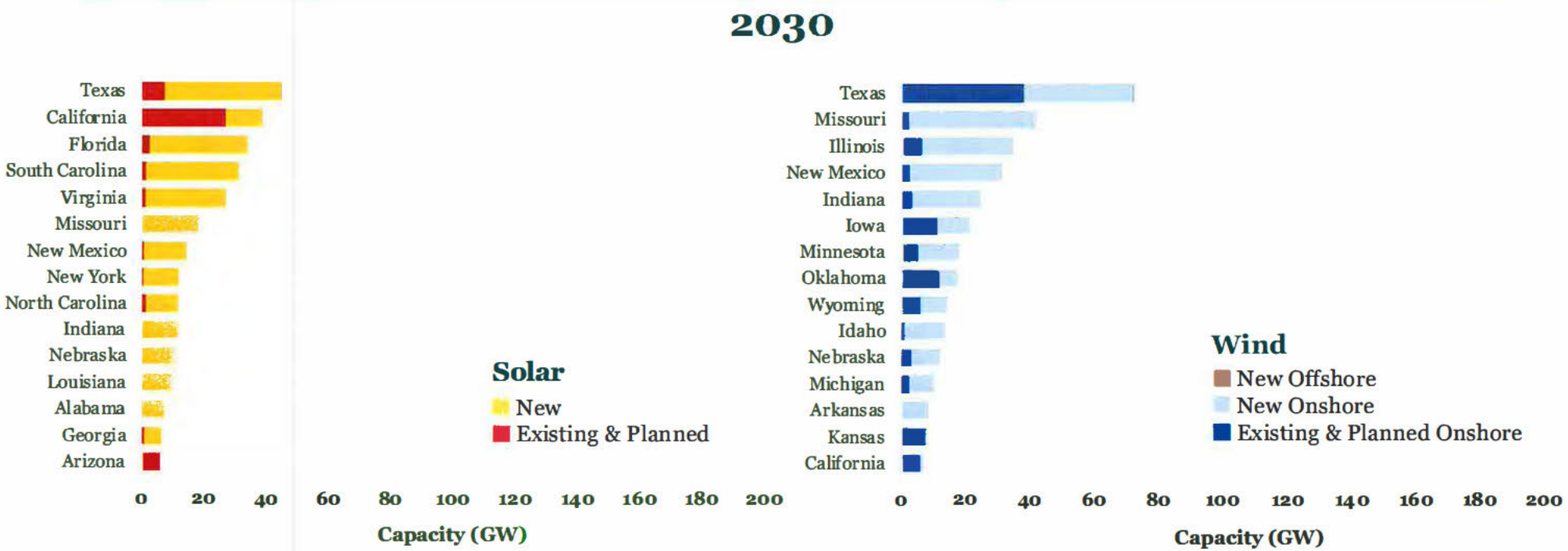
Installed solar and wind capacity, top-ranked states, E+ Base





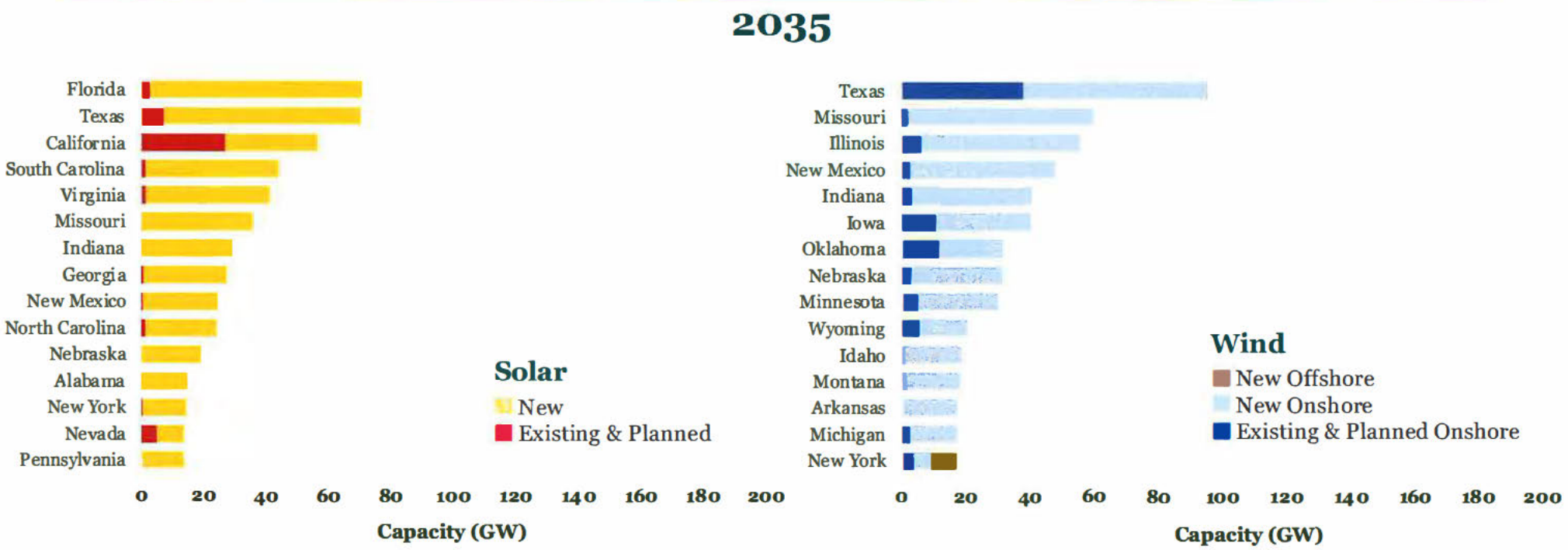
Installed solar and wind capacity, top-ranked states, E+ Base





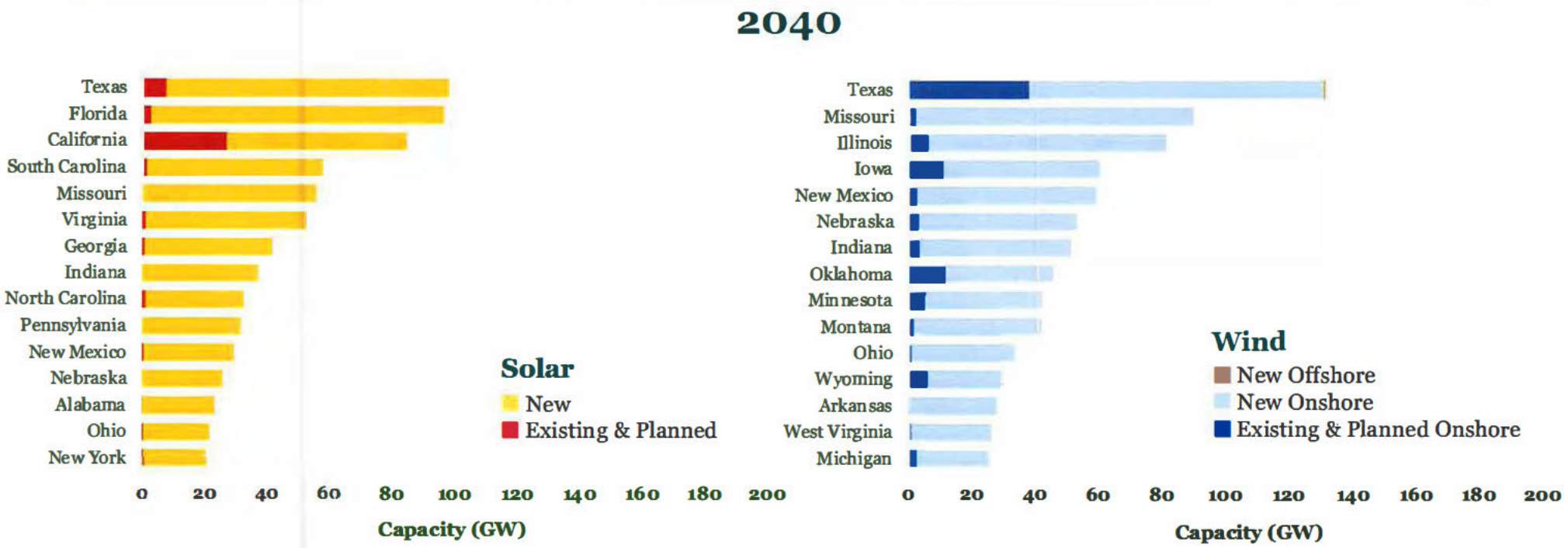
Installed solar and wind capacity, top-ranked states, E+ Base





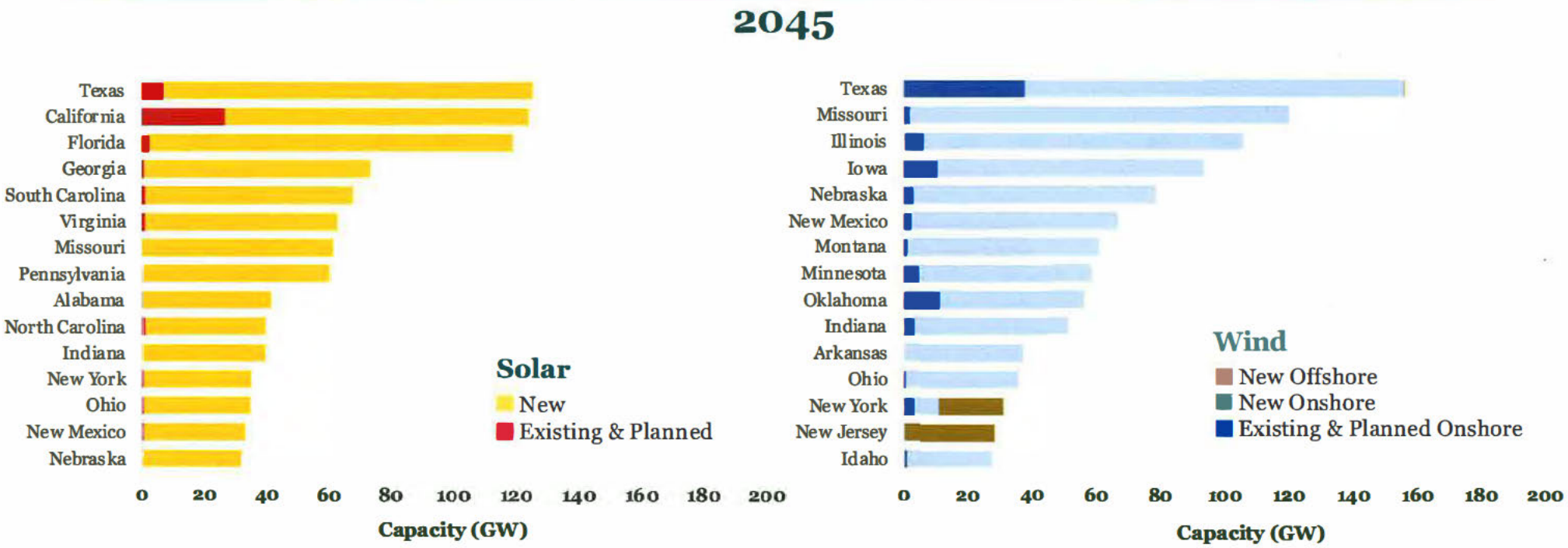
Installed solar and wind capacity, top-ranked states, E+ Base





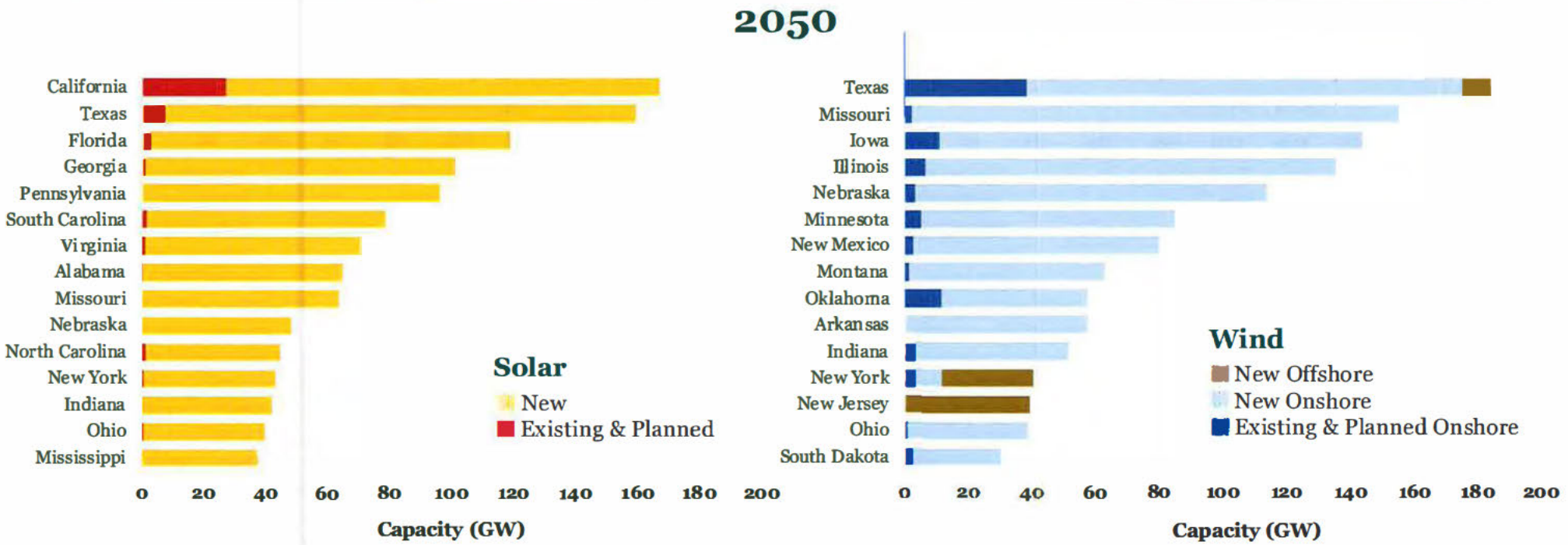
Installed solar and wind capacity, top-ranked states, E+ Base





Installed solar and wind capacity, top-ranked states, E+ Base

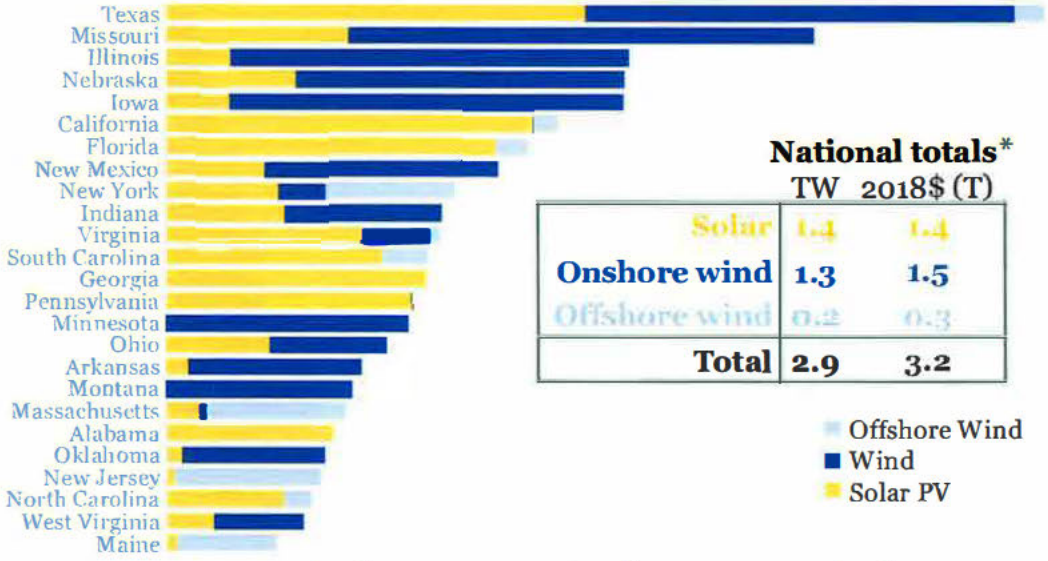




Capital investment in solar and wind generating projects, top-ranked states



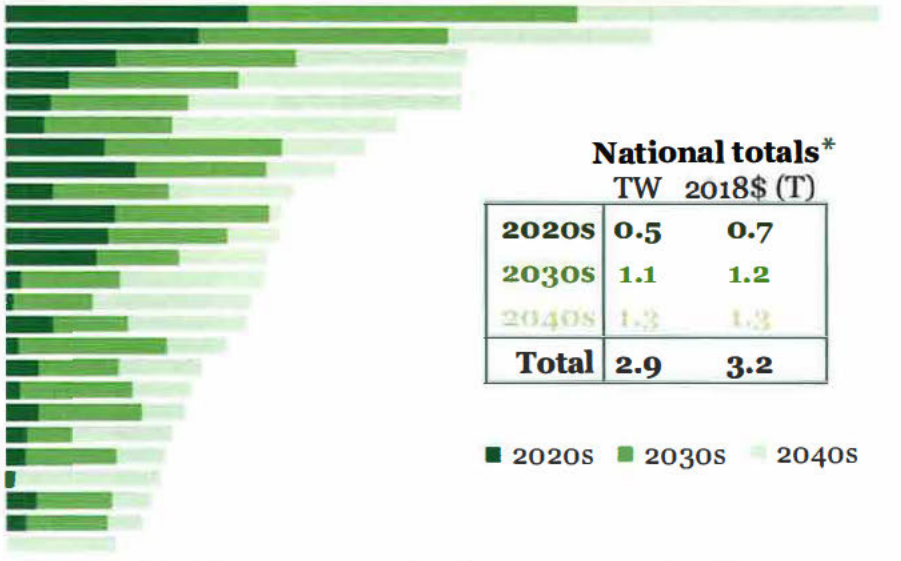
E+ (Base siting)
cumulative (2021-2050), by project type



National totals*

	TW	2018$ (T)
Solar	1.4	1.4
Onshore wind	1.3	1.5
Offshore wind	0.2	0.3
Total	2.9	3.2

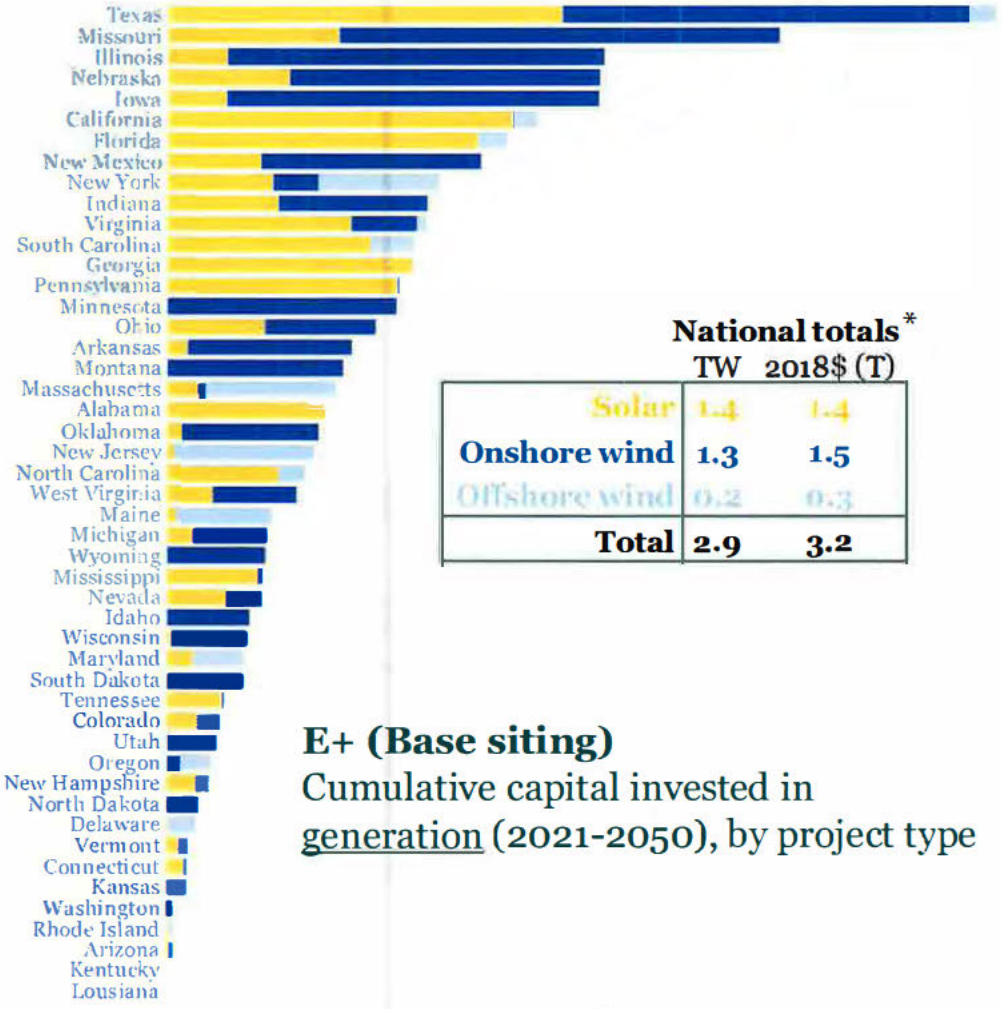
E+ (Base siting)
cumulative (wind & solar), by decade



National totals*

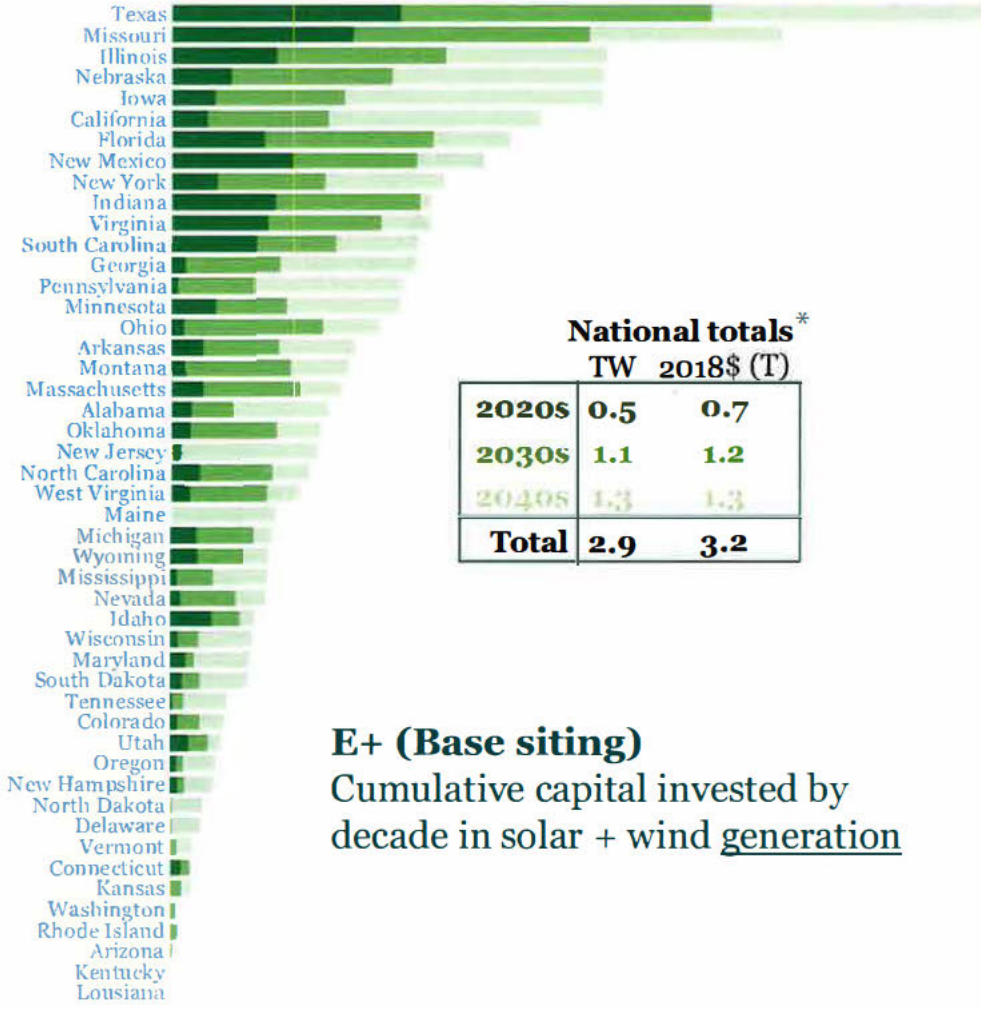
	TW	2018$ (T)
2020s	0.5	0.7
2030s	1.1	1.2
2040s	1.3	1.3
Total	2.9	3.2

* National total TW are cumulative capacity built from 2021 – 2050. This differs from capacity in place in 2050 by the amount already in place in 2020, for which no additional investment is required.



National totals*	TW	2018$ (T)
Solar	1.4	1.4
Onshore wind	1.3	1.5
Offshore wind	0.2	0.3
Total	**2.9**	**3.2**

E+ (Base siting)
Cumulative capital invested in generation (2021-2050), by project type



National totals*	TW	2018$ (T)
2020s	0.5	0.7
2030s	1.1	1.2
2040s	1.3	1.3
Total	**2.9**	**3.2**

E+ (Base siting)
Cumulative capital invested by decade in solar + wind generation

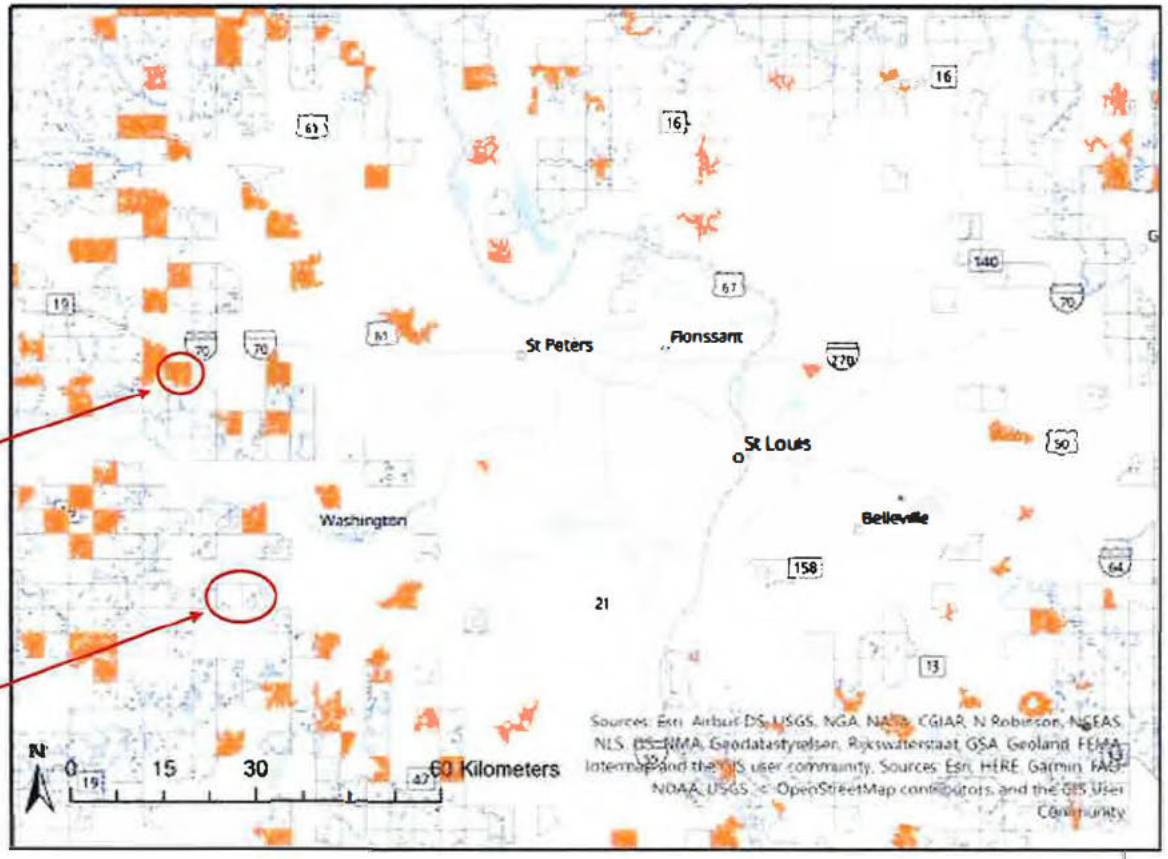
* National total TW are cumulative capacity built from 2021 – 2050. This differs from capacity in place in 2050 by the amount already in place in 2020, for which no additional investment is required.

Example area detail: St. Louis, MO
2050 E+ wind and solar farms (Base site availability)

- Solar, existing and planned
- Solar, additional selected sites 2050 E+ base
- Wind, existing and planned
- Wind, additional selected sites 2050 E+ base
  (dots indicate approximate turbine footprint)

500 MW solar facility
(generic future facility)

80 MW wind facility
(generic future facility)



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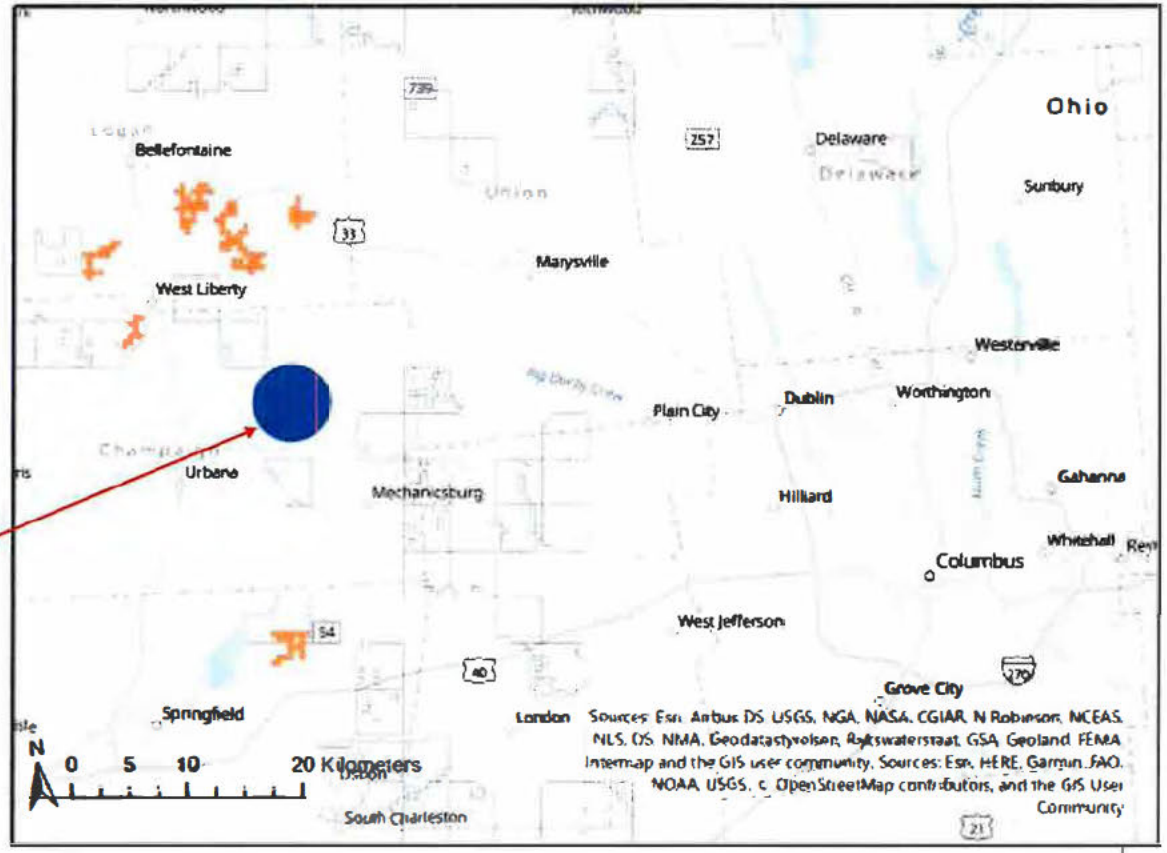
Carbon Mitigation Initiative

Example area detail: Columbus, OH
2050 E+ wind and solar farms (Base site availability)

- Solar, existing and planned
- Solar, additional selected sites 2050 E+ base
- Wind, existing and planned
- Wind, additional selected sites 2050 E+ base (dots indicate approximate turbine footprint)



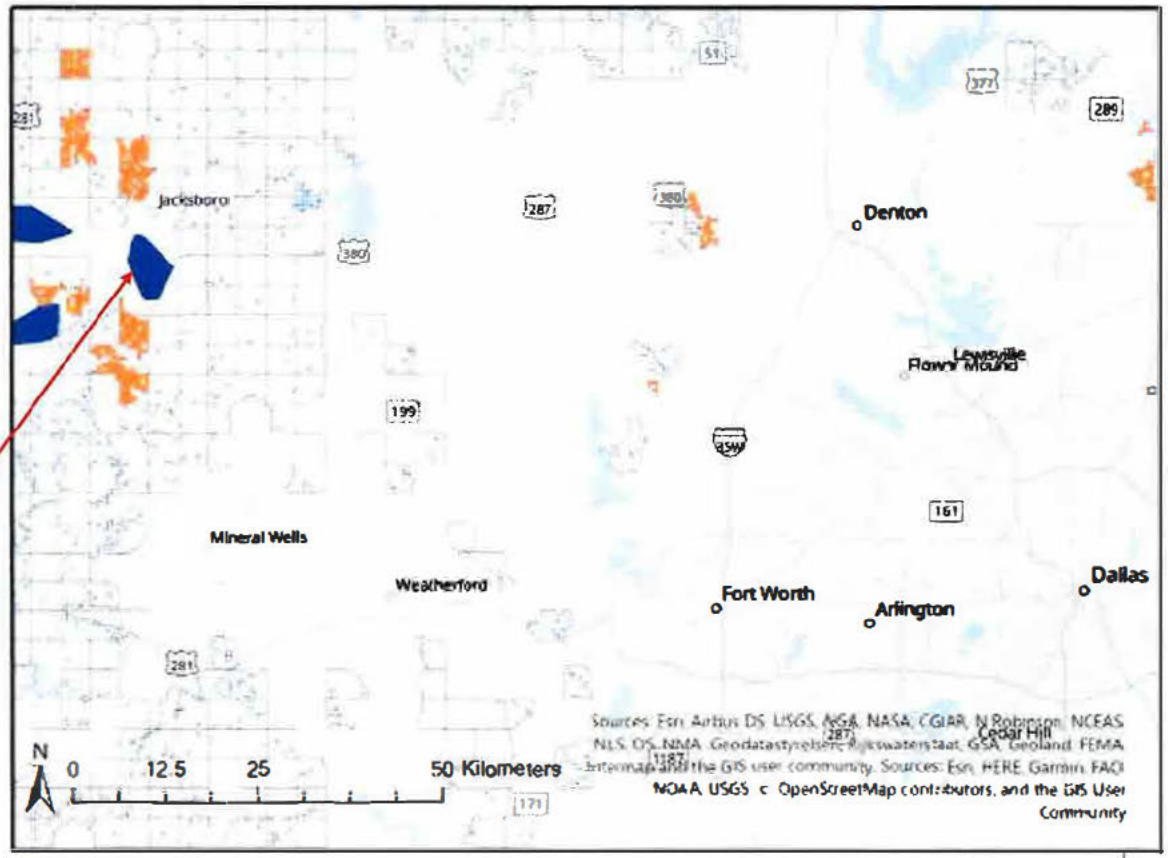
Buckeye Wind
99 MW proposed facility
Scheduled online date = 2021
Population density = 14 people / km²

Example area detail: Dallas – Fort Worth, TX
2050 E+ wind and solar farms (Base site availability)

- Solar, existing and planned
- Solar, additional selected sites 2050 E+ base
- Wind, existing and planned
- Wind, additional selected sites 2050 E+ base
  (dots indicate approximate turbine footprint)

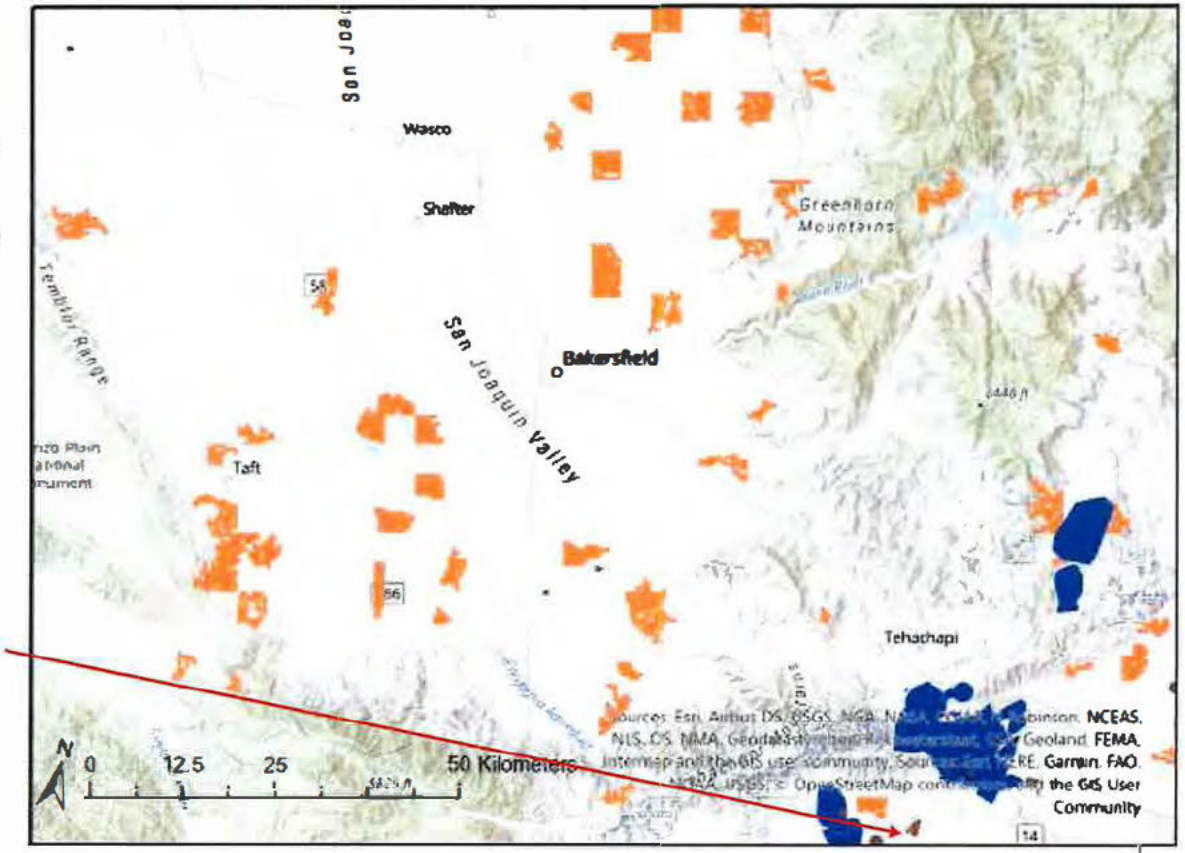
Keechi Wind
110 MW existing facility
Online date = 2015
Population density = 0 people / km²

[Town of Jacksboro (7 km away) has population density > 100 p/km²]



Example area detail: Bakersfield, CA
2050 E+ wind and solar farms (Base site availability)

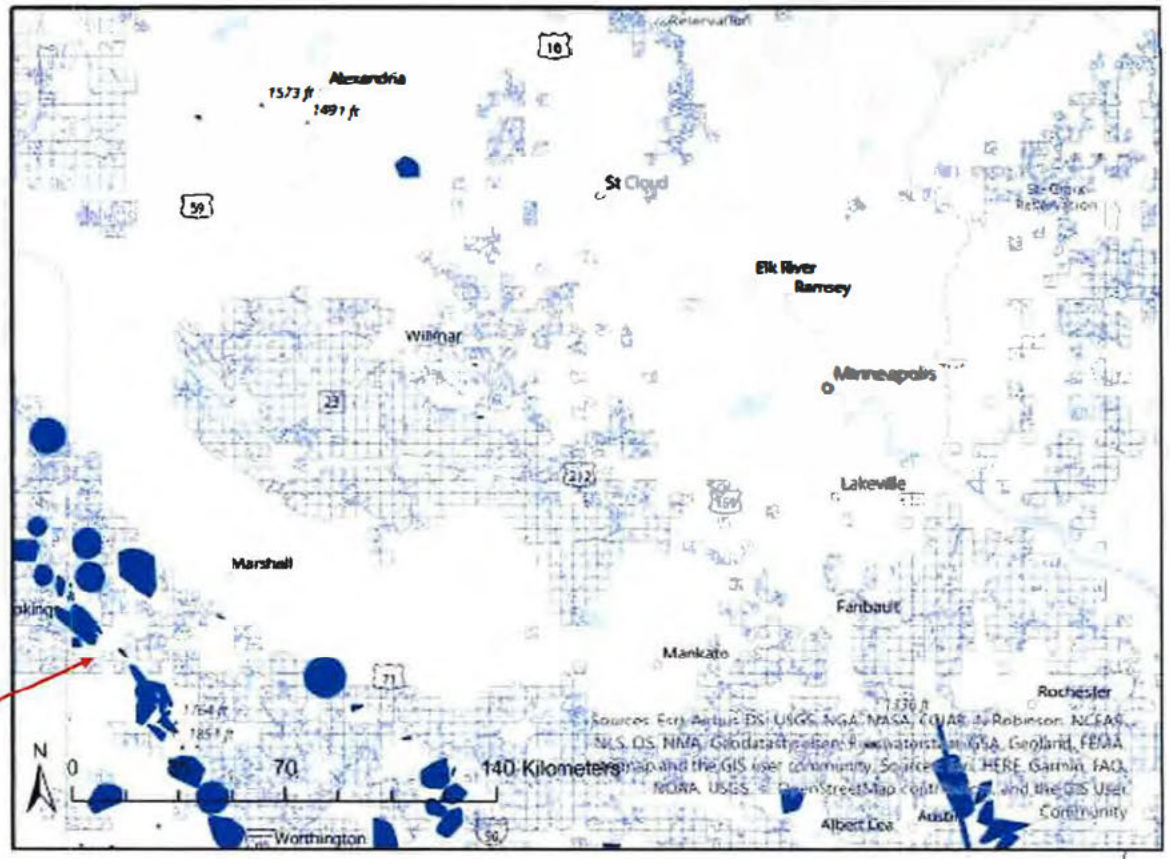
- Solar, existing and planned
- Solar, additional selected sites 2050 E+ base
- Wind, existing and planned
- Wind, additional selected sites 2050 E+ base
  (dots indicate approximate turbine footprint)



Catalina Solar
110 MW existing facility
Online date = 2014
Population density = 4 people / km²

Example area detail: Minneapolis, MN
2050 E+ wind and solar farms (Base site availability)

- Solar, existing and planned
- Solar, additional selected sites 2050 E+ base
- Wind, existing and planned
- Wind, additional selected sites 2050 E+ base
  (dots indicate approximate turbine footprint)



Note siting of new wind farm adjacent existing facilities

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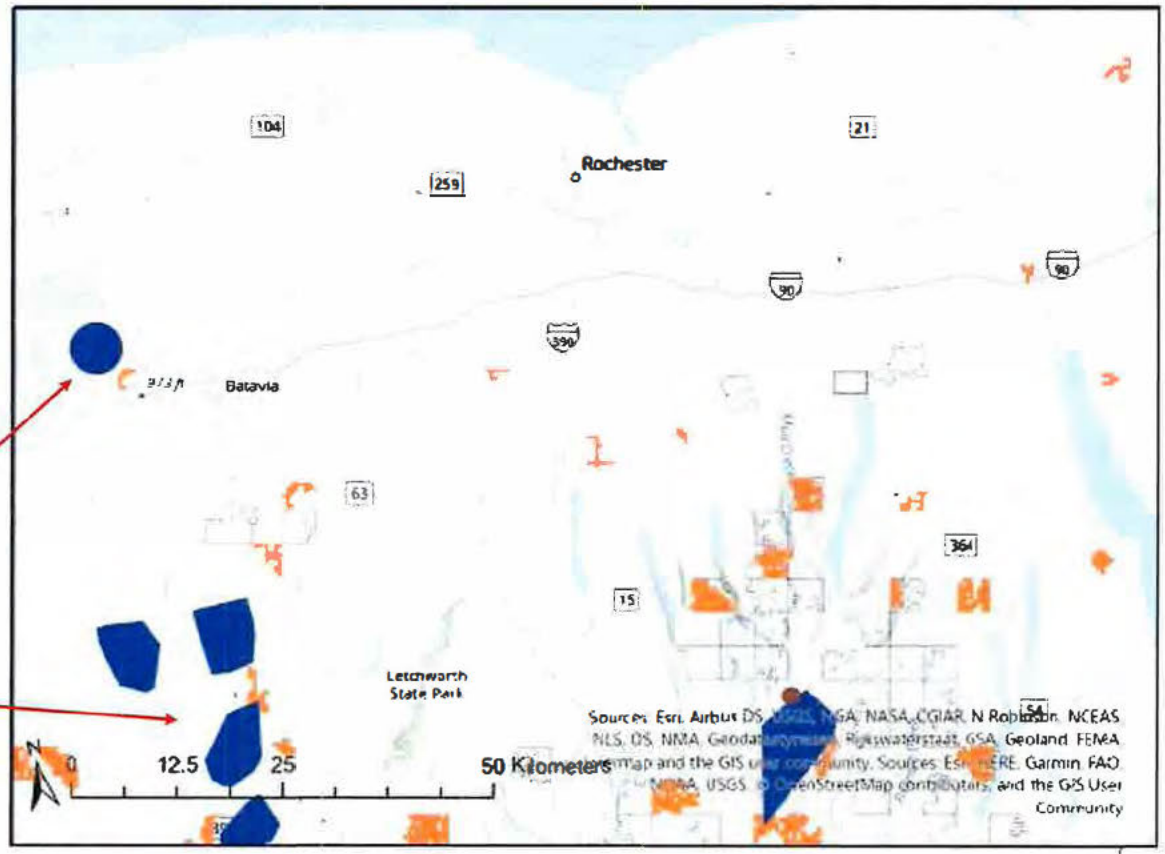
Carbon Mitigation Initiative

Example area detail: Rochester, NY
2050 E+ wind and solar farms (Base site availability)

- Solar, existing and planned
- Solar, additional selected sites 2050 E+ base
- Wind, existing and planned
- Wind, additional selected sites 2050 E+ base
  (dots indicate approximate turbine footprint)

Alabama Ledge Wind
80 MW proposed facility
Scheduled online date = 2021

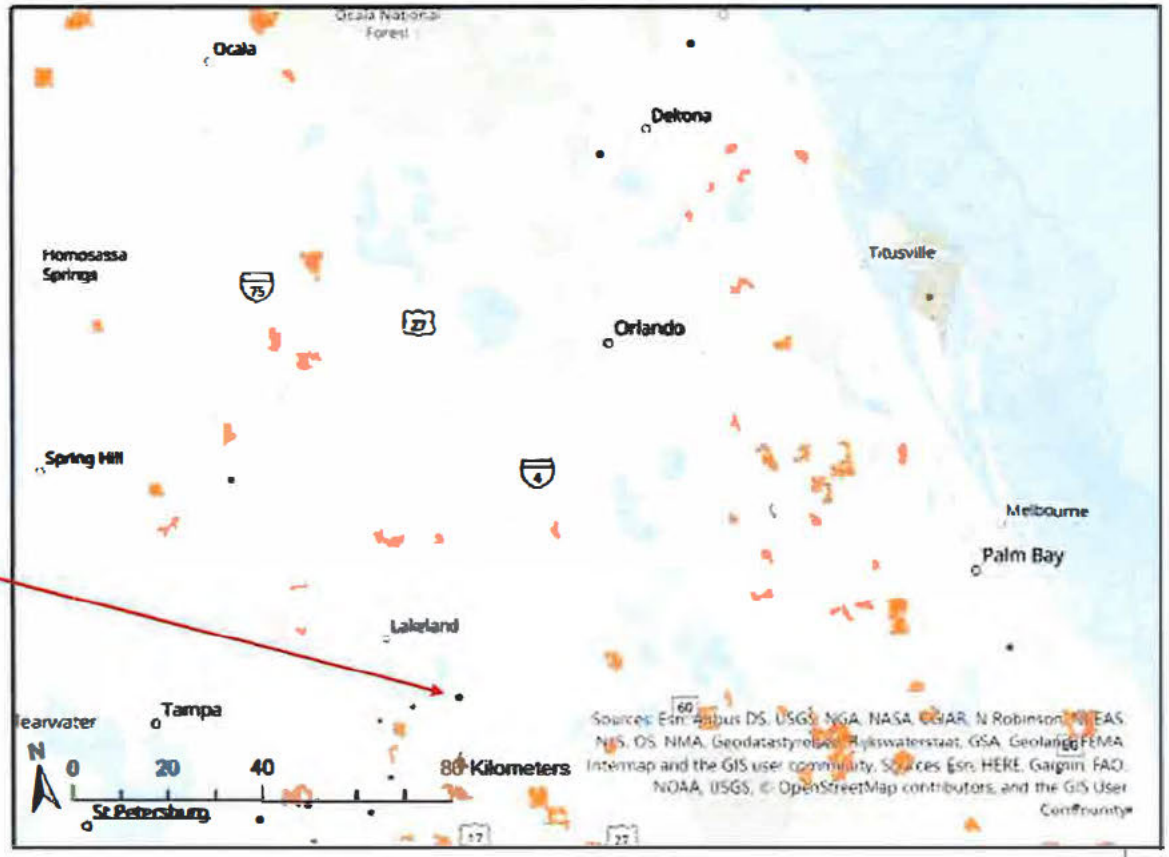
Existing wind facilities



Example area detail: Orlando, FL
2050 E+ wind and solar farms (Base site availability)

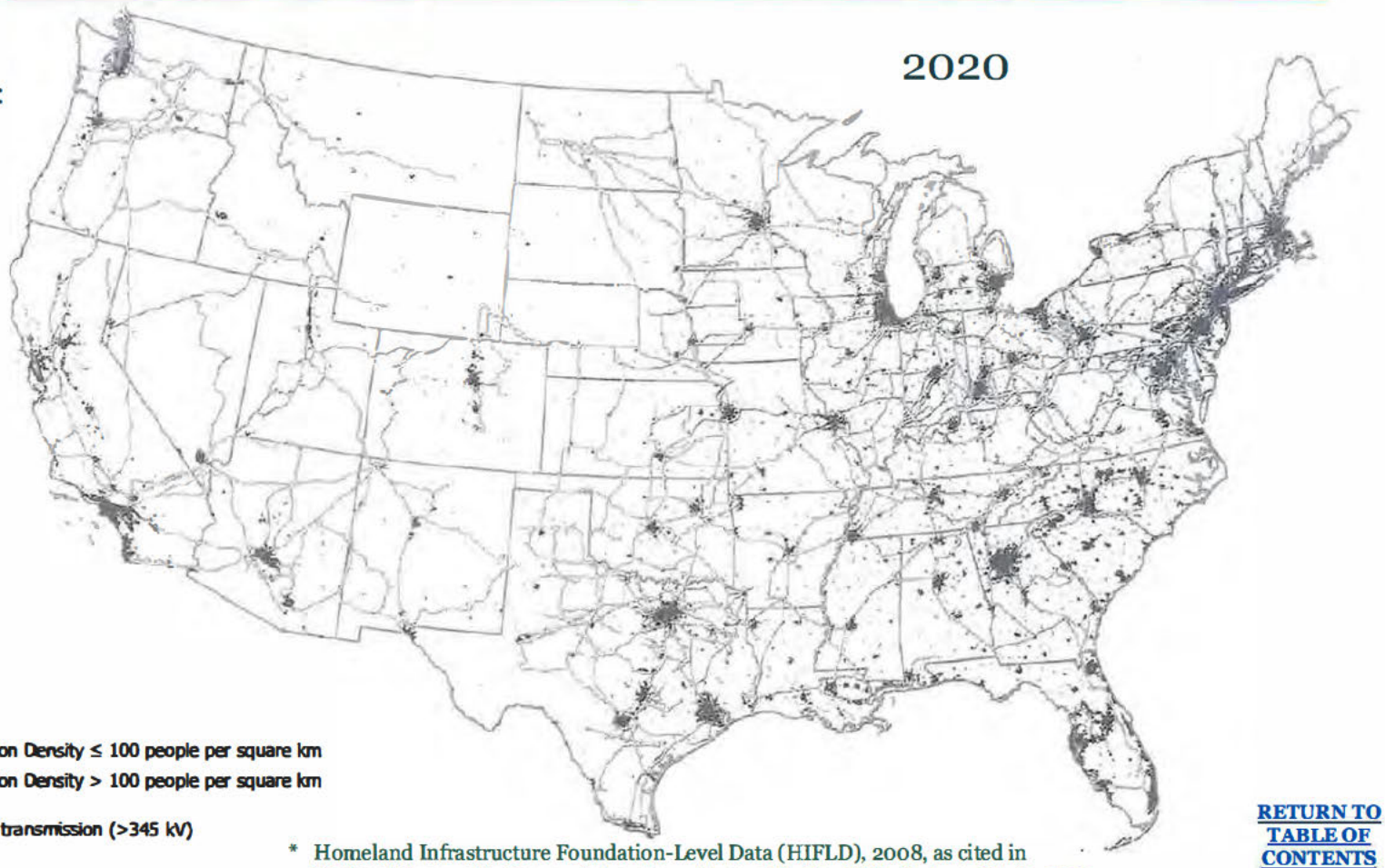
- Solar, existing and planned
- Solar, additional selected sites 2050 E+ base
- Wind, existing and planned
- Wind, additional selected sites 2050 E+ base
  (dots indicate approximate turbine footprint)

Peace Creek Solar
57 MW proposed facility
Scheduled online date = 2020



Transmission system in 2020 (≥ 345 kV lines shown)

Total transmission capacity:
~320,000 GW-km*



* Homeland Infrastructure Foundation-Level Data (HIFLD), 2008, as cited in National Renewable Energy Laboratory, Renewable Electricity Futures Study, 2012.

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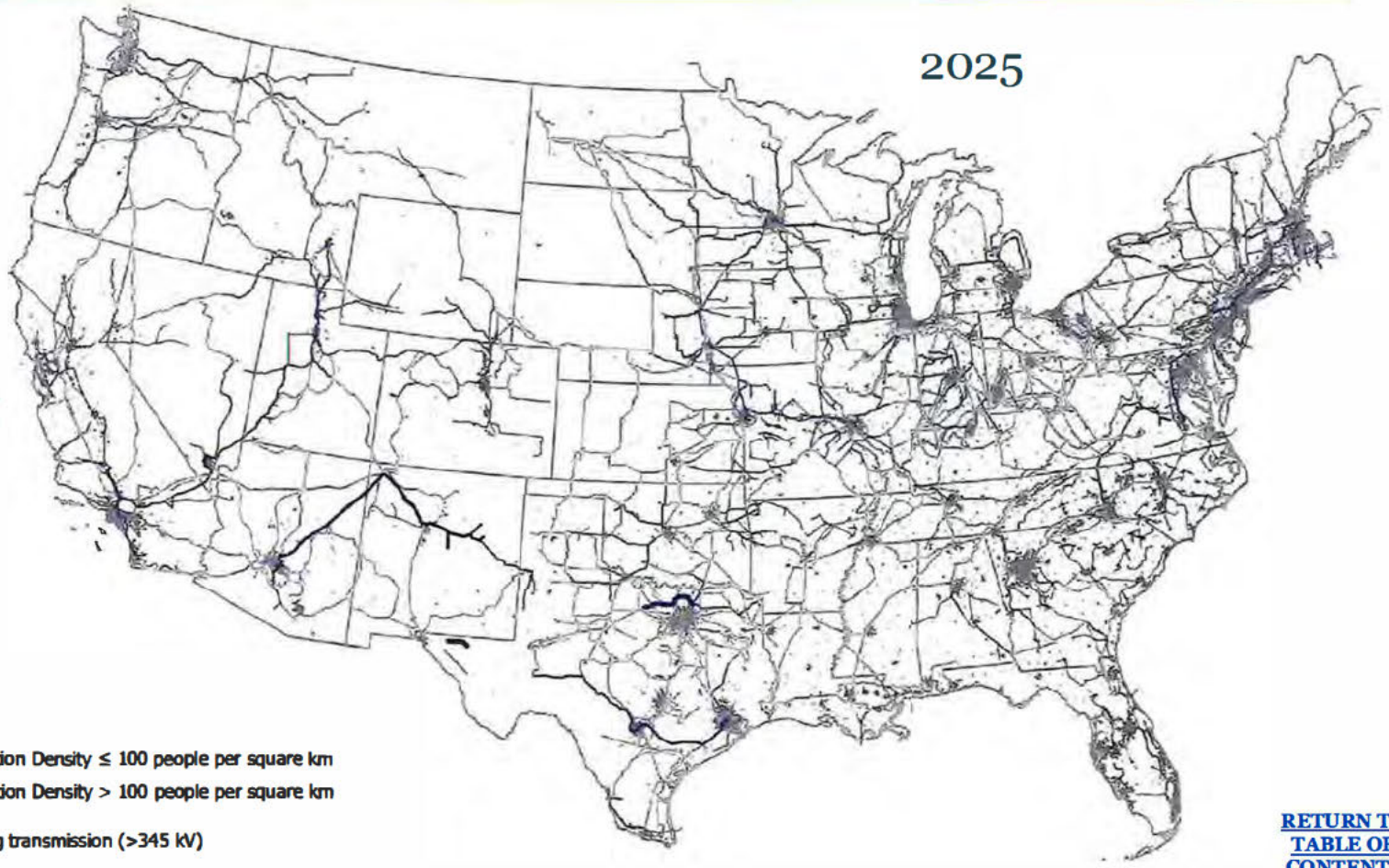
Transmission expansions to support wind and solar generation in E+ scenario with Base siting availability, 2025

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 98,500 GW-km (31% increase from 2020)
- capital in service: 150 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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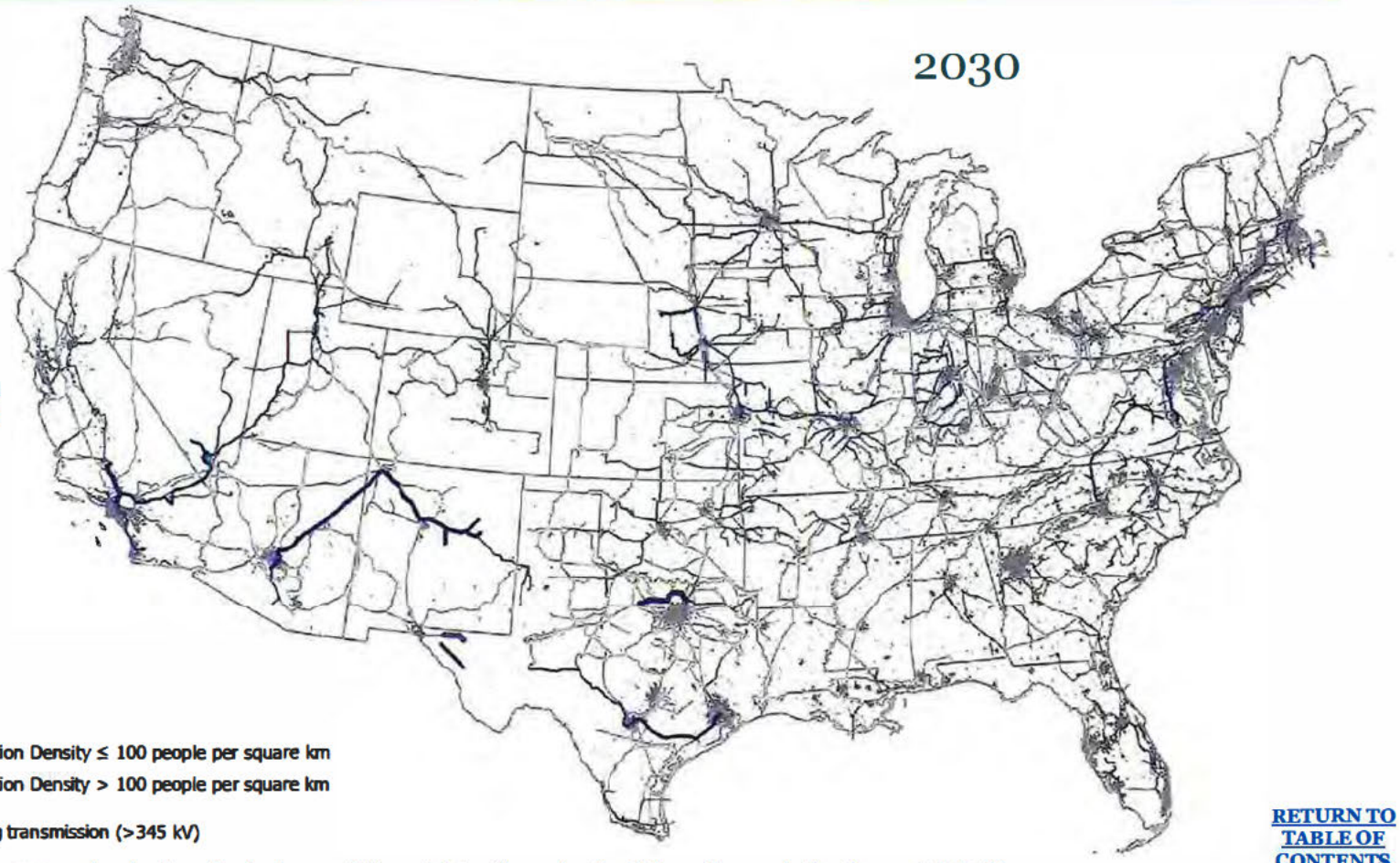
Transmission expansions to support wind and solar generation in E+ scenario with Base siting availability, 2030

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 196,000 GW-km (61% increase from 2020)
- capital in service: 360 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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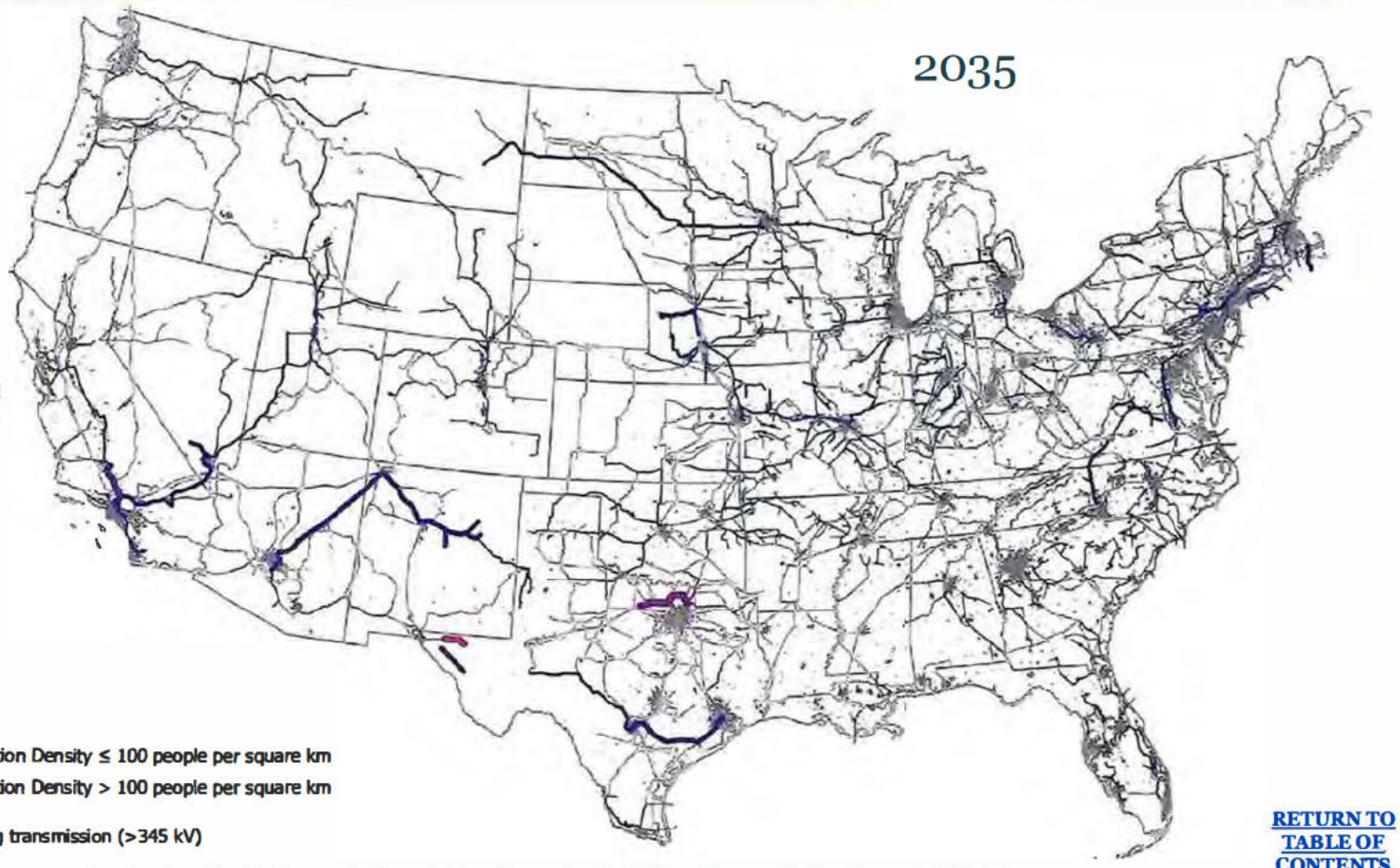
Transmission expansions to support wind and solar generation in E+ scenario with Base siting availability, 2035

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 331,500 GW-km (104% increase from 2020)
- capital in service: 670 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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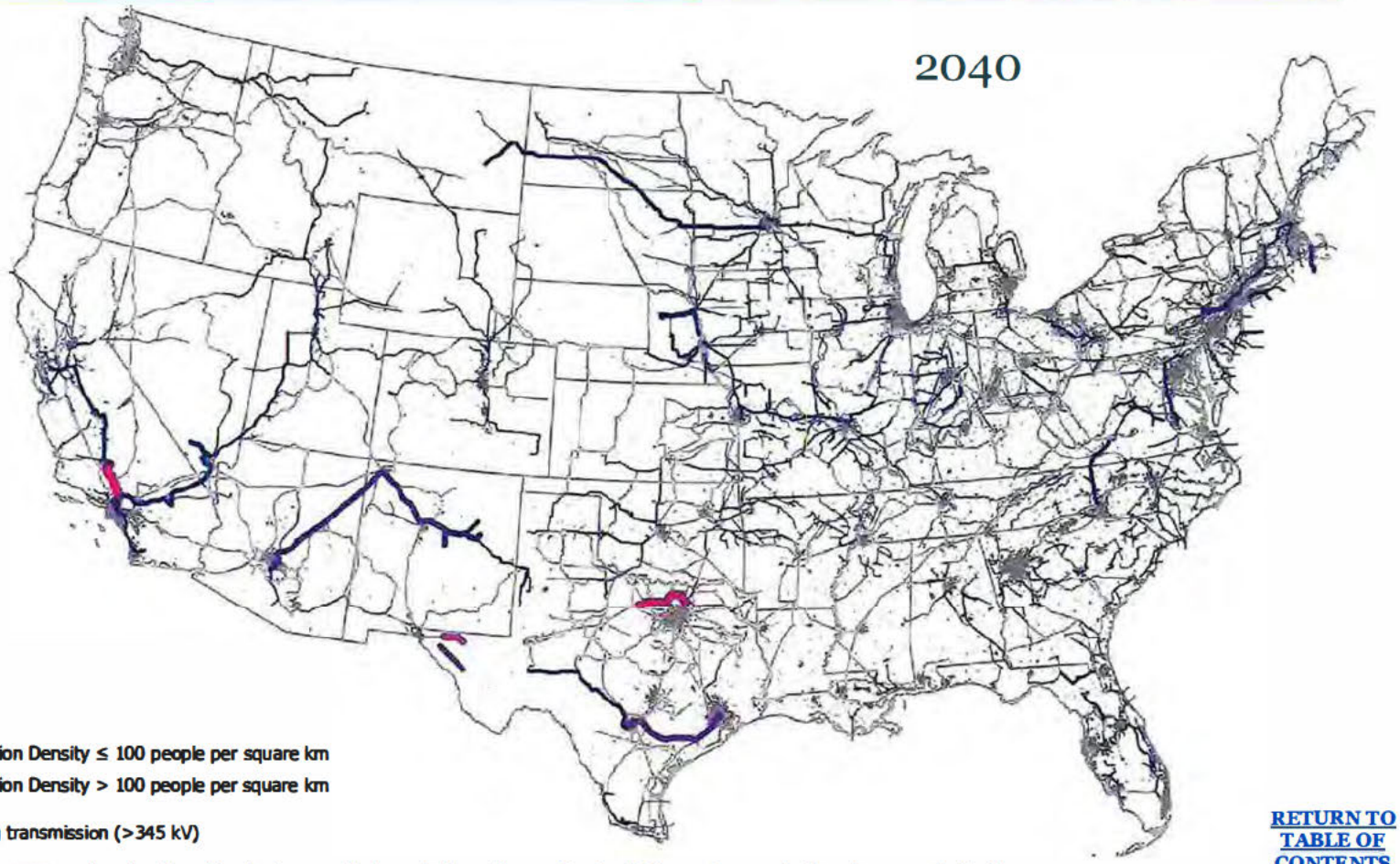
Transmission expansions to support wind and solar generation in E+ scenario with Base siting availability, 2040

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 448,500 GW-km (140% increase from 2020)
- capital in service: 1,090 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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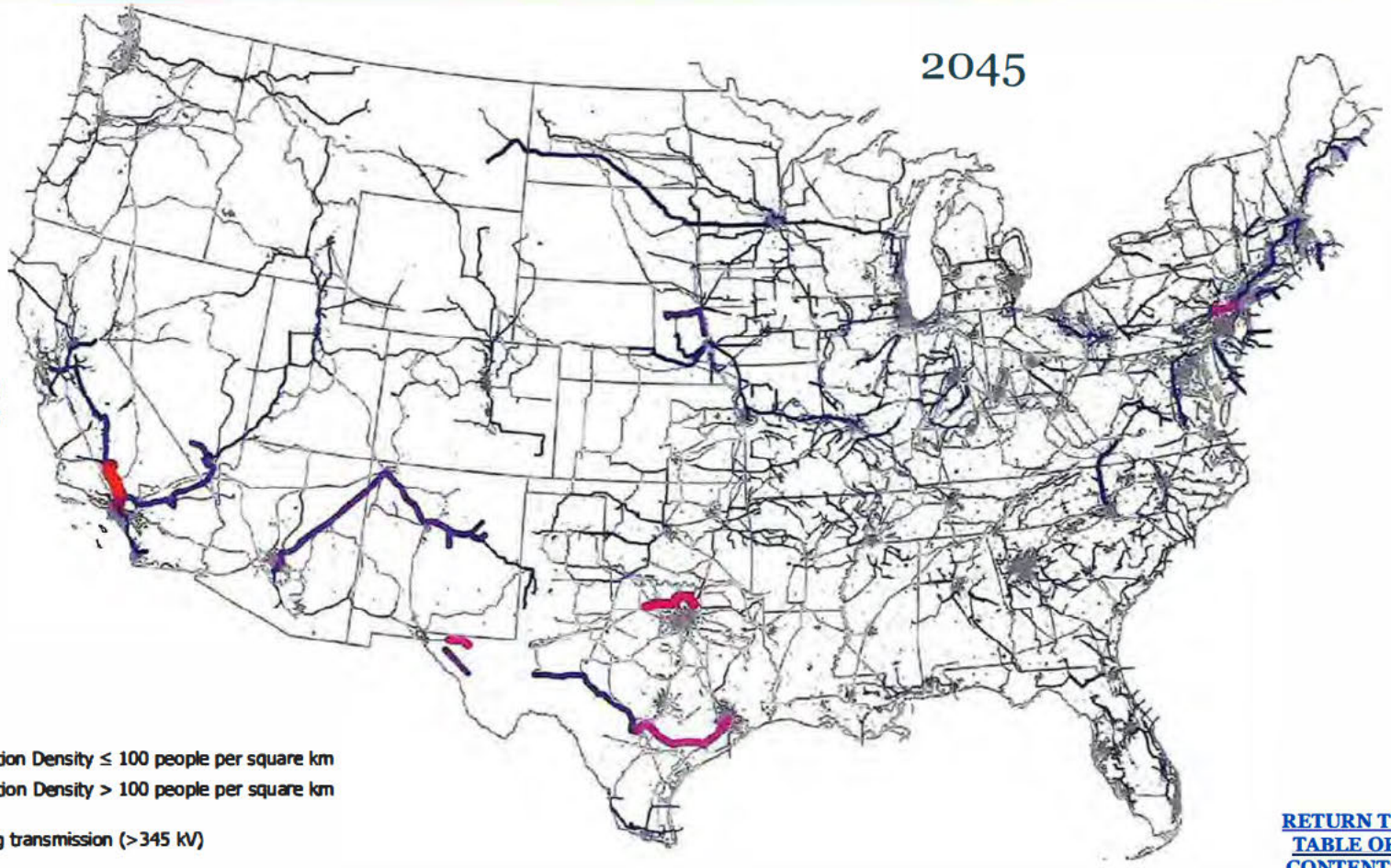
Transmission expansions to support wind and solar generation in E+ scenario with Base siting availability, 2045

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 667,200 GW-km (209% increase from 2020)
- capital in service: 1,630 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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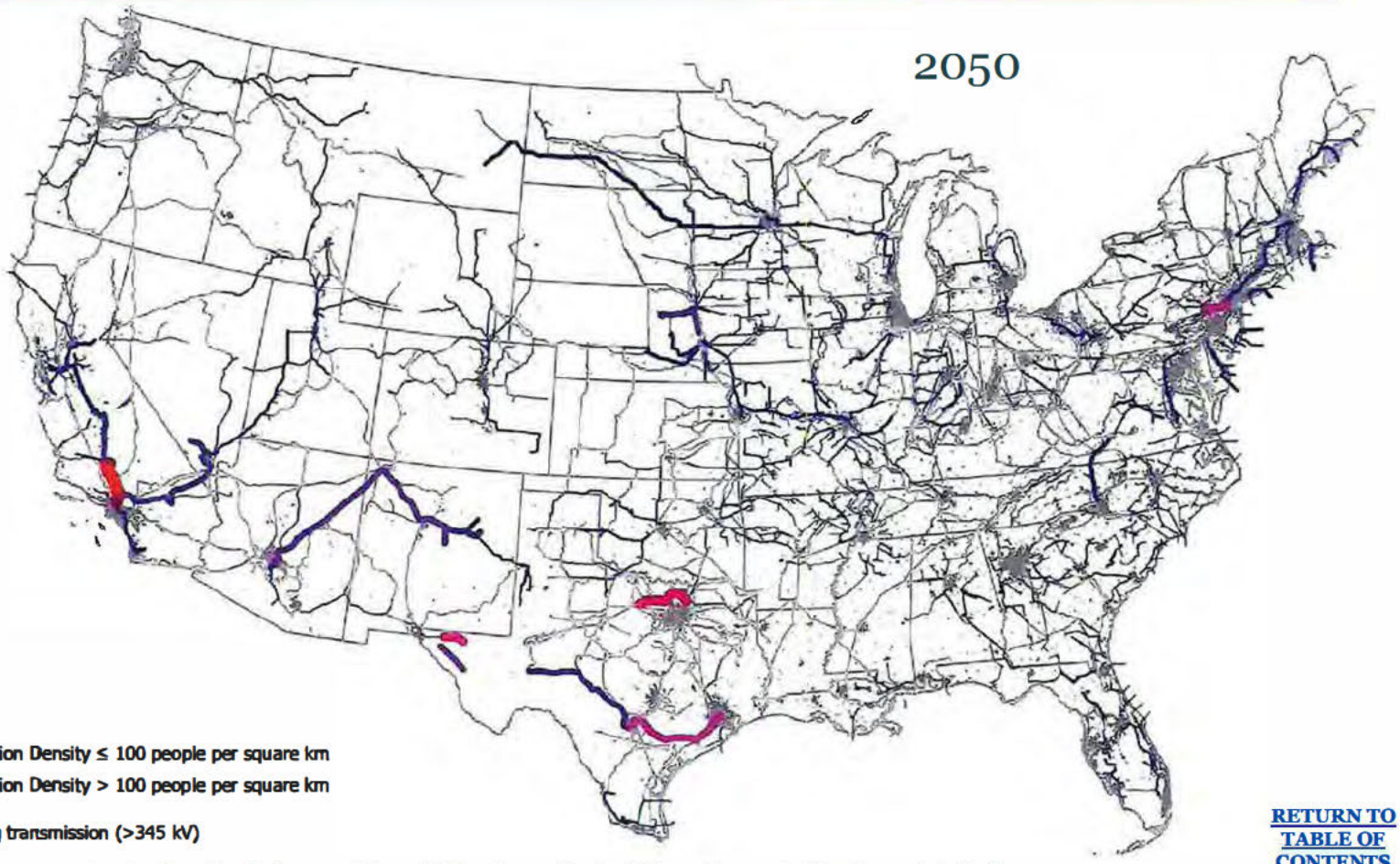
Transmission expansions to support wind and solar generation in E+ scenario with Base siting availability, 2050

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 691,700 GW-km (216% increase from 2020)
- capital in service: 2,360 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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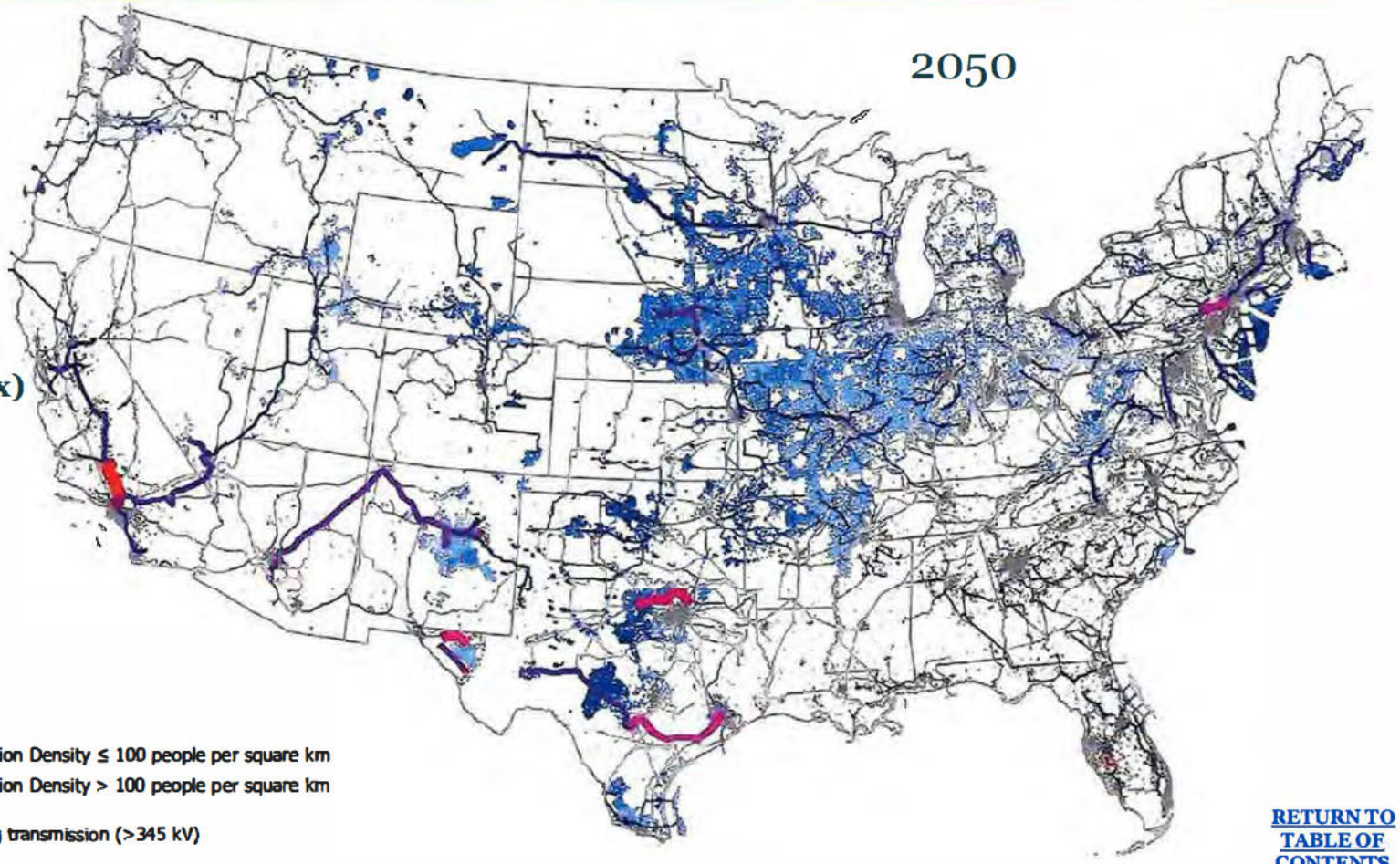
To support wind and solar generation in E+ scenario with Base siting availability, total transmission capacity more than **triples**.

Transmission & generators.

Note: Capacity factors at generator sites are reflected in color intensity, with highest CF = darkest color.

2020 transmission capacity:
~320,000 GW-km

2050 transmission capacity:
~1,012,000 GW-km (3.2x)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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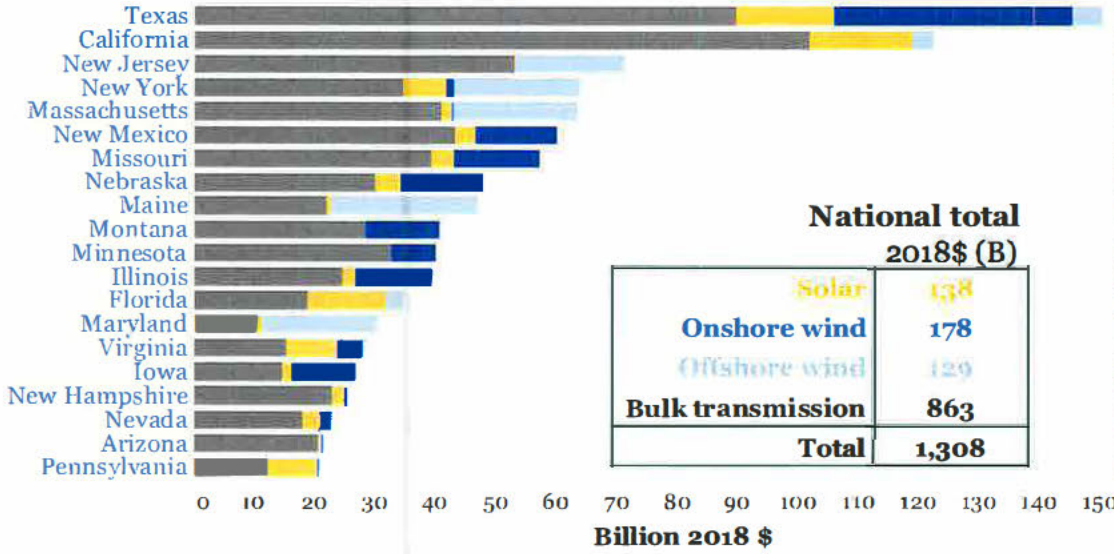
Capital investment in transmission, top-ranked states

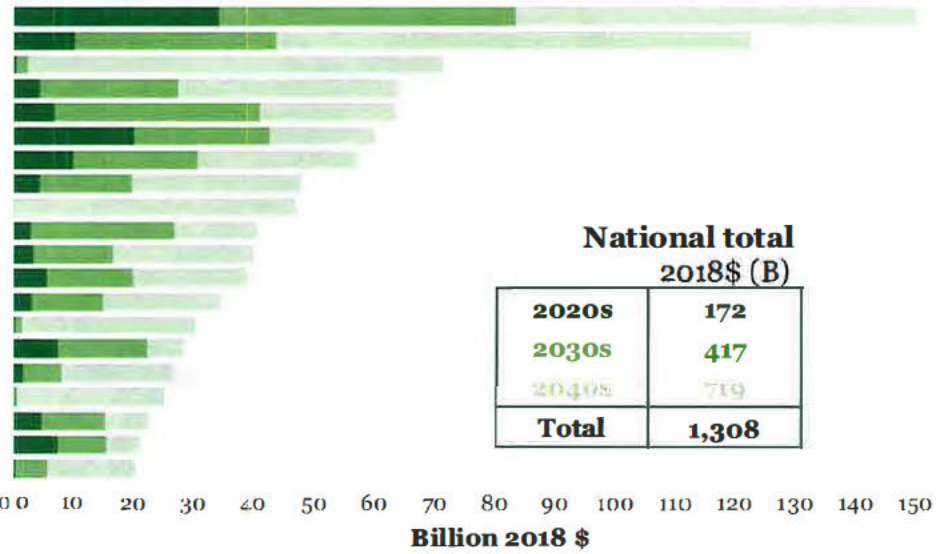


E+ (Base siting)
cumulative (2020-2050), by project type



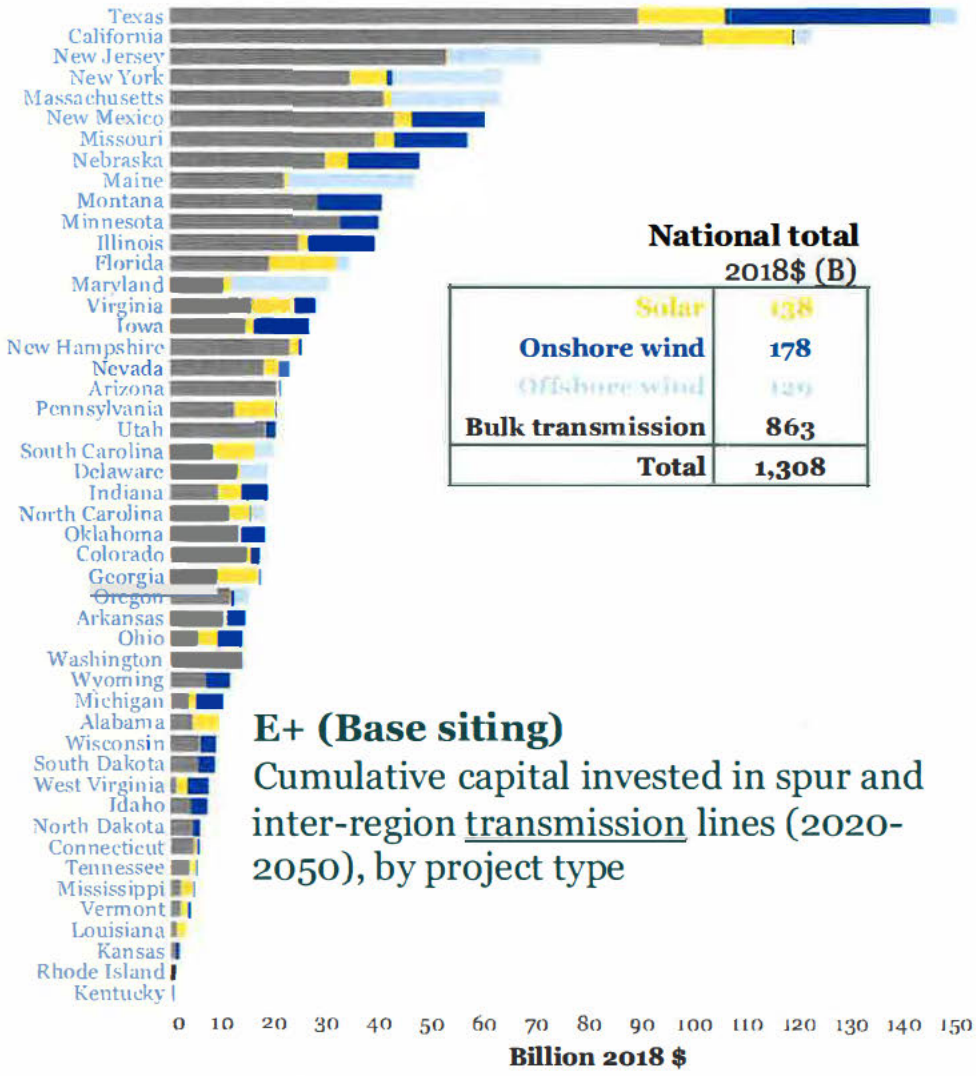
National total 2018$ (B)	
Solar	138
Onshore wind	178
Offshore wind	129
Bulk transmission	863
Total	1,308

E+ (Base siting)
cumulative (wind & solar), by decade



National total 2018$ (B)	
2020s	172
2030s	417
2040s	719
Total	1,308

Note: These capital estimates are for transmission expansions. The values labeled solar, onshore wind, and offshore wind are spur lines from solar or wind projects to nearest substations. Sustaining capital invested for end-of-life line replacements is not included in the totals here, but is included in transmission capital investment estimates in the capital mobilization section of this report.

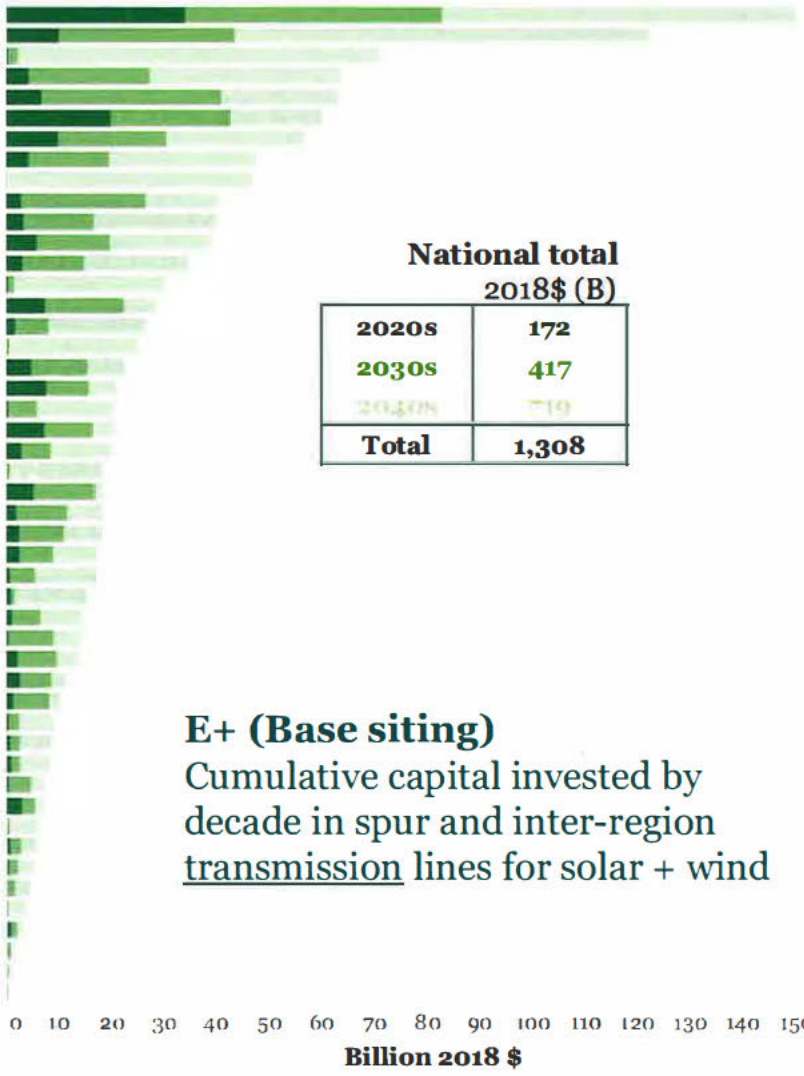


National total
2018$ (B)

Solar	138
Onshore wind	**178**
Offshore wind	129
Bulk transmission	**863**
Total	**1,308**

E+ (Base siting)

Cumulative capital invested in spur and inter-region transmission lines (2020-2050), by project type



National total
2018$ (B)

2020s	**172**
2030s	**417**
2040s	719
Total	**1,308**

E+ (Base siting)

Cumulative capital invested by decade in spur and inter-region transmission lines for solar + wind

Note: These capital estimates are for transmission expansions. The values labeled solar, onshore wind, and offshore wind are spur lines from solar or wind projects to nearest substations. Sustaining capital invested for end-of-life line replacements is not included in the totals here, but is included in transmission capital investment estimates in the capital mobilization section of this report.

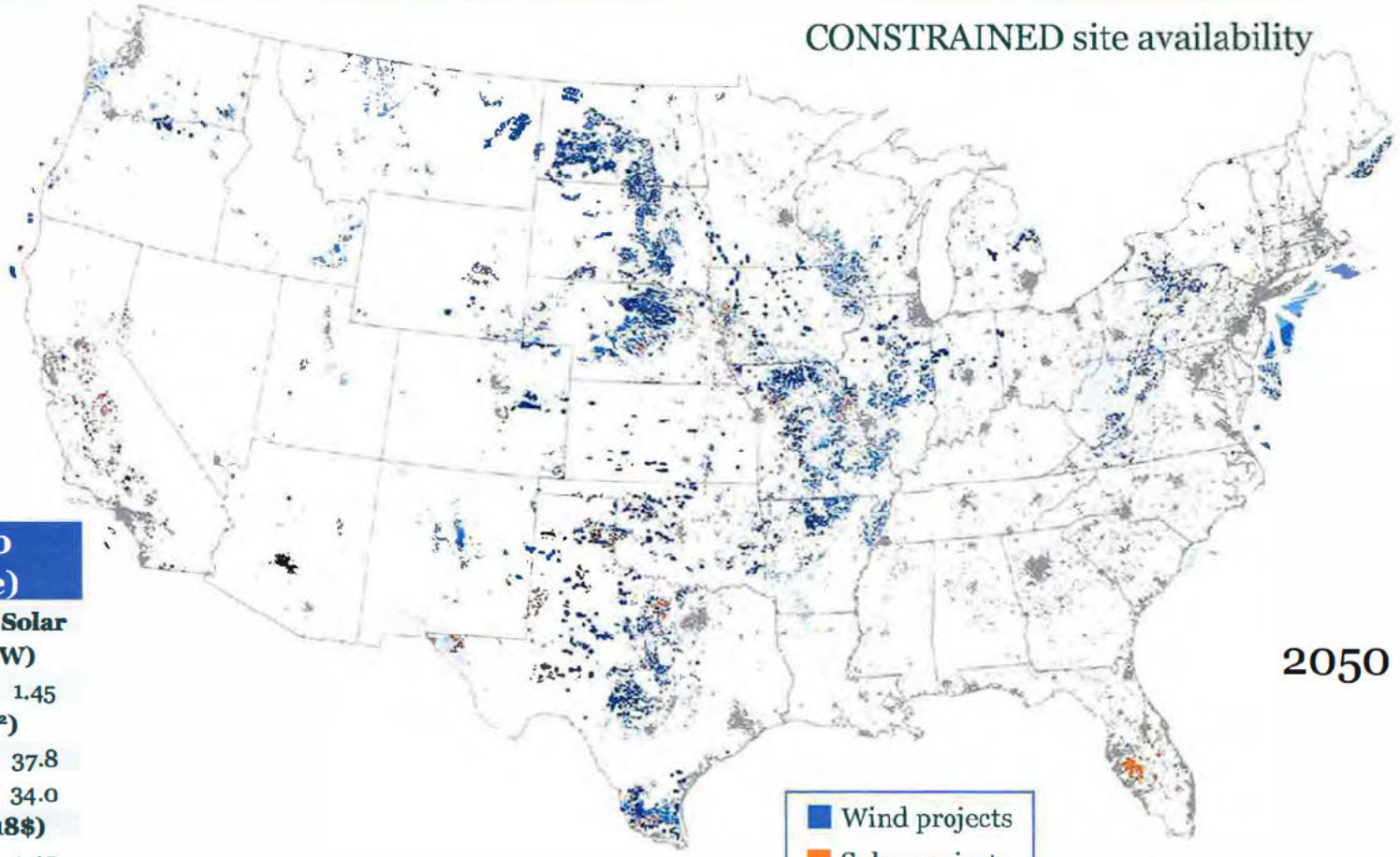
Mapping solar and wind generators and transmission for the E+ pathway with Constrained land availability



Summary of this section

- In the Constrained land availability scenario, wind farms cannot be deployed on prime farmlands and neither wind nor solar can be sited in relatively intact landscapes (in addition to all land use screens applied in the Base scenario).
- These additional constraints, particularly the prime farmlands exclusion for wind power, requires a more dispersed deployment of wind across the Great Plains states, shifting capacity from Iowa, Minnesota and Oklahoma to North Dakota, South Dakota and Texas.
- The ranking of top 10 solar states are unaffected relative to Base land availability.
- About $3.4 trillion is invested in ~3.0 TW of wind and solar capacity by 2050.
- Total onshore wind and solar farm area (~600,000 km²) and directly impacted land area (~40,000 km²) are similar to the Base land availability scenario.
- The footprint of wind and to a lesser extent solar, is significant and will require sensitive engagement with communities to assure ongoing support. Downscaling offers useful resources to plan local engagement.
- Constrained land availability requires greater transmission expansion than Base availability, as wind farms push into more remote areas of the Great Plains states. Transmission capacity expands ~75% by 2030 and 3.5x through 2050.
- Total capital invested in transmission is ~$530b through 2030 and $2.5 trillion by 2050.

Constrained land availability scenario leads to more dispersed wind and solar development across U.S. — 2050 E+ Constrained siting



2020 - 2050 (cumulative)	Wind	Solar
Capacity installed (TW)	1.61	1.45
Land used (1000 km²)		
Total	564	37.8
Direct	5.6	34.0
Capital invested (2018$)		
Trillion $	1.94	1.45

Note: Site capacity factors are reflected in color intensity (highest CF = darkest color).

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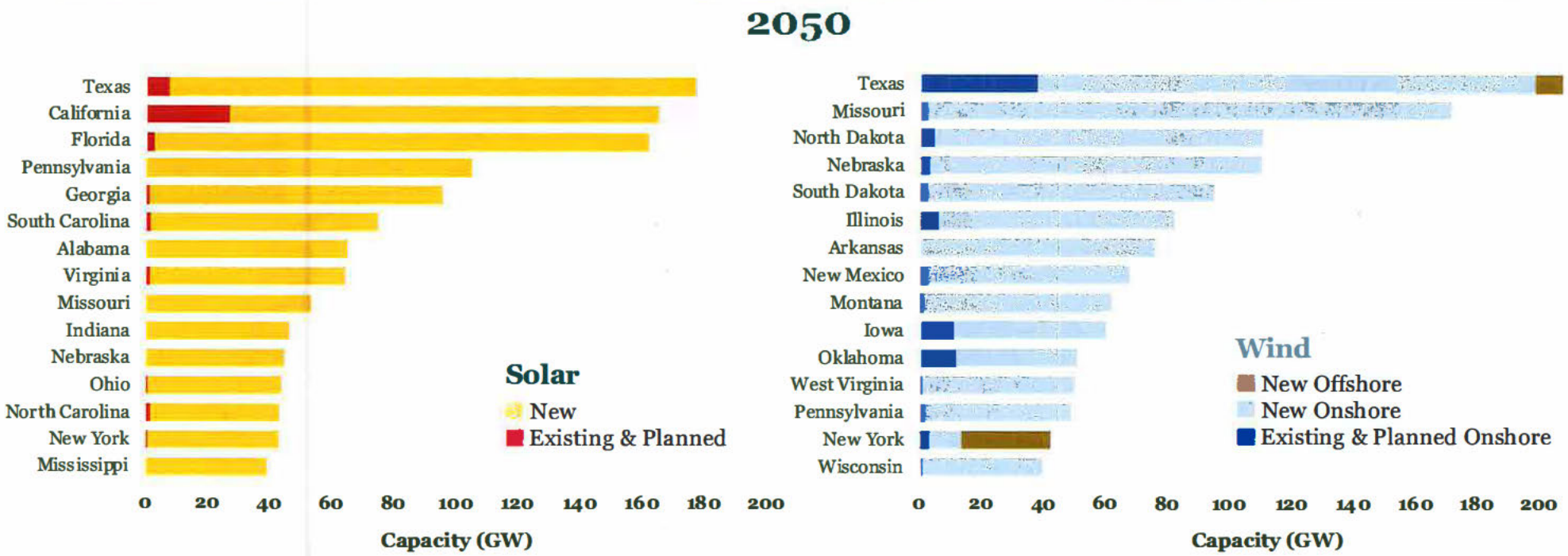
Installed solar and wind capacity, top-ranked states, E+ Constrained

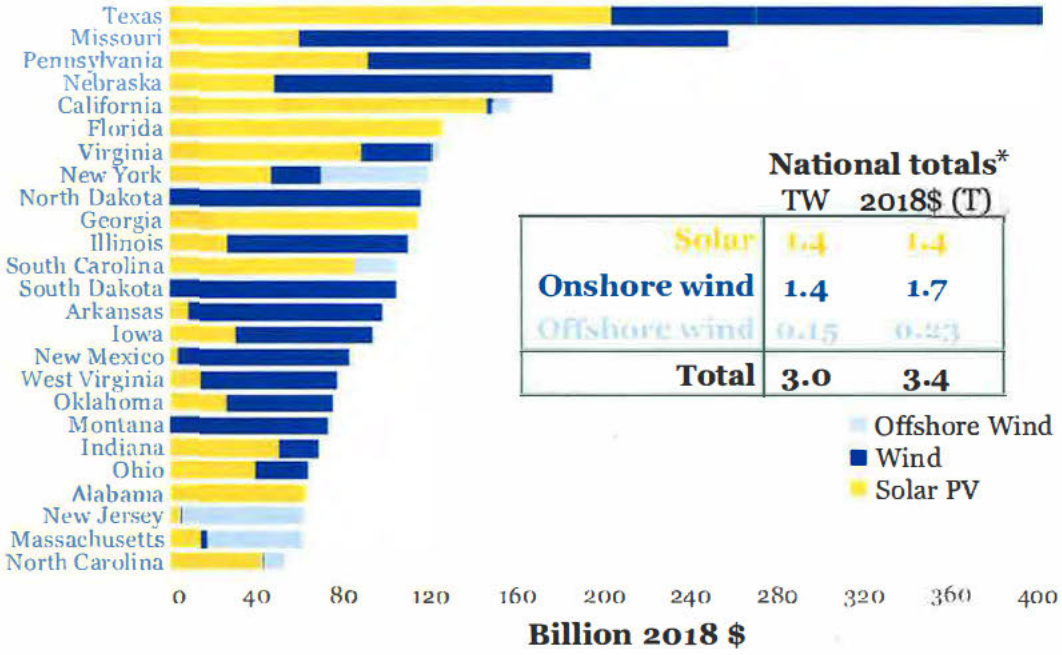




Capital investment in solar and wind generating projects, top-ranked states



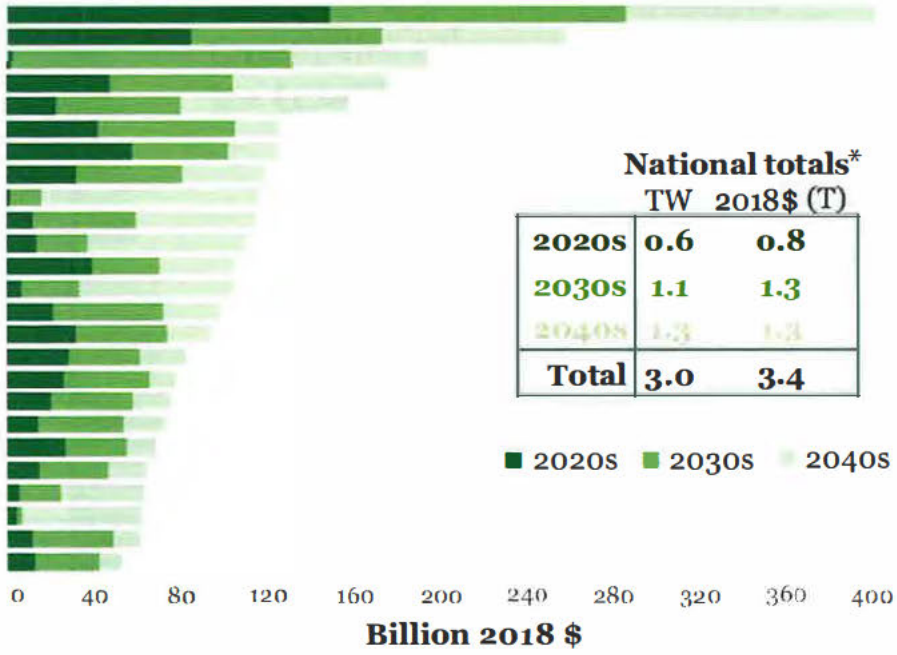
E+ (Constrained siting)
cumulative (2021-2050), by project type



National totals*

	TW	2018$ (T)
Solar	1.4	1.4
Onshore wind	1.4	1.7
Offshore wind	0.15	0.23
Total	3.0	3.4

E+ (Constrained siting)
cumulative (wind & solar), by decade



National totals*

	TW	2018$ (T)
2020s	0.6	0.8
2030s	1.1	1.3
2040s	1.3	1.3
Total	3.0	3.4

* National total TW are cumulative capacity built from 2021 – 2050. This differs from capacity in place in 2050 by the amount already in place in 2020, for which no additional investment is required.

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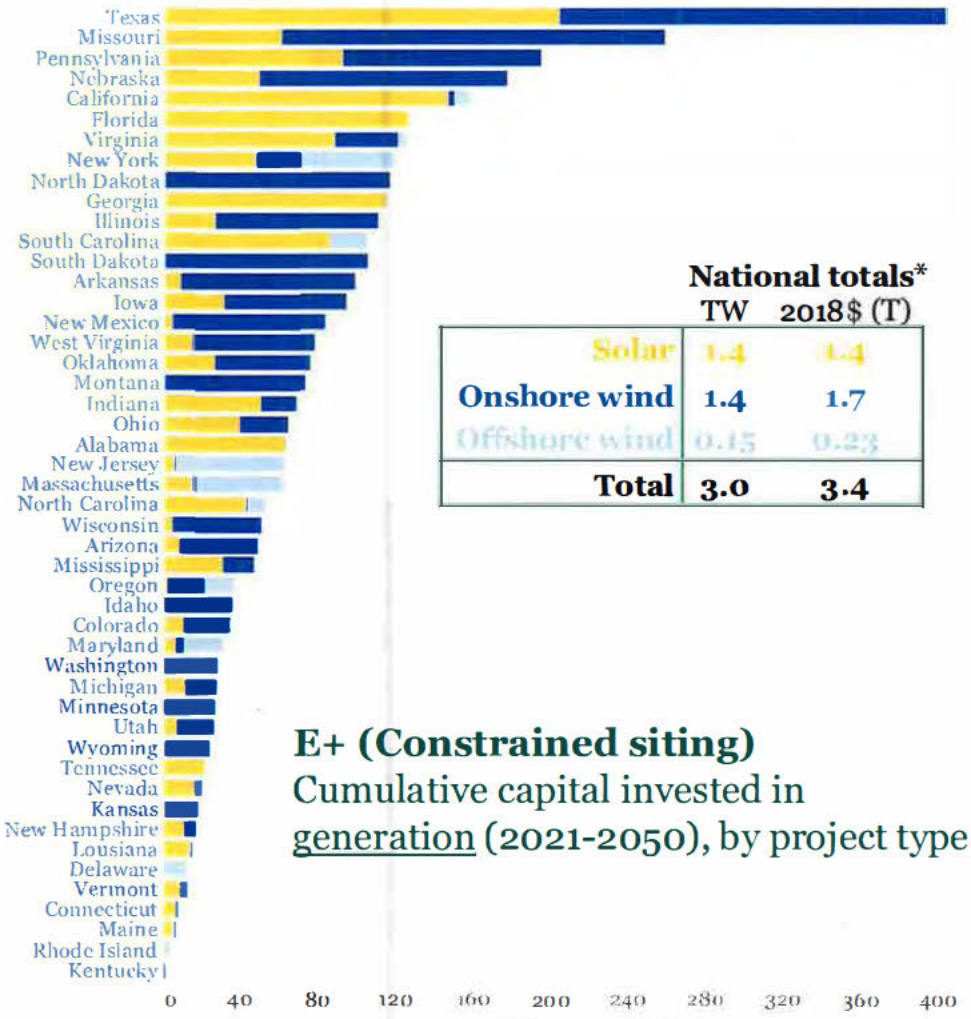
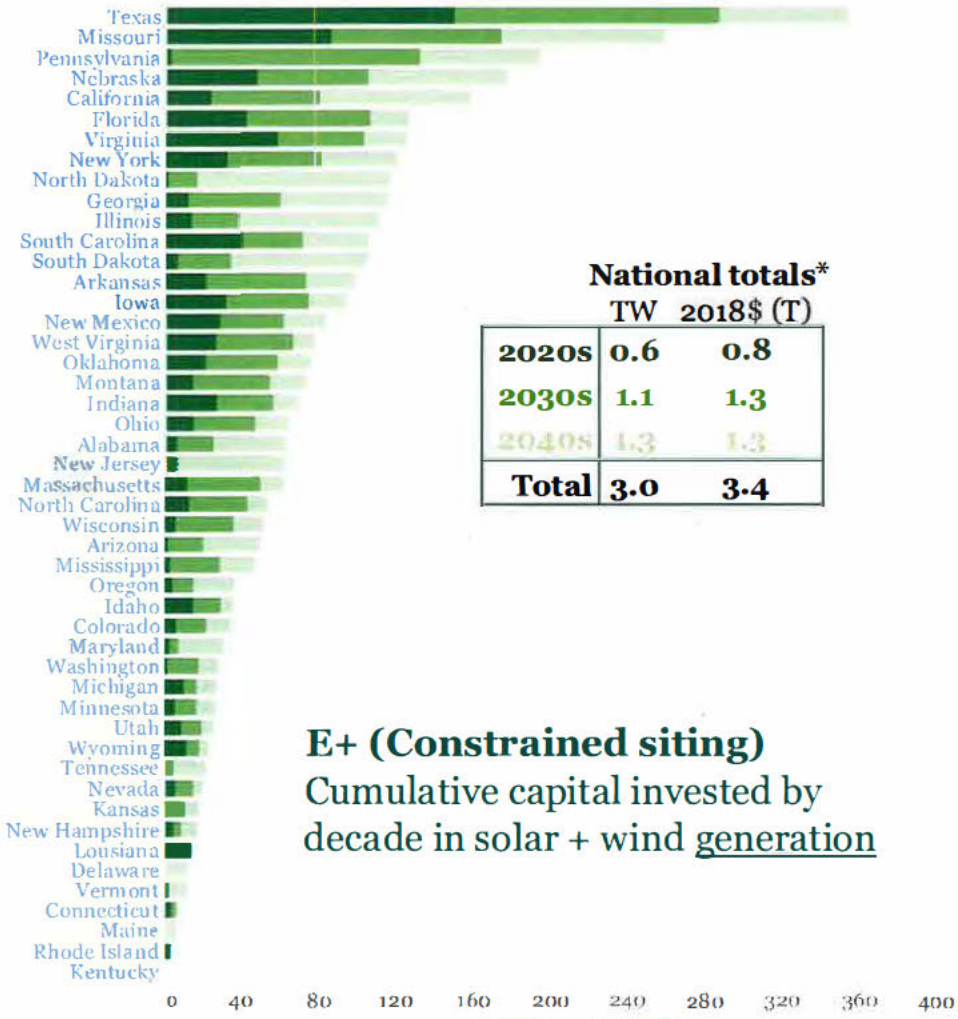
Carbon Mitigation Initiative



National totals*	TW	2018$ (T)
Solar	1.4	1.4
Onshore wind	1.4	1.7
Offshore wind	0.15	0.23
Total	**3.0**	**3.4**

E+ (Constrained siting)
Cumulative capital invested in generation (2021-2050), by project type



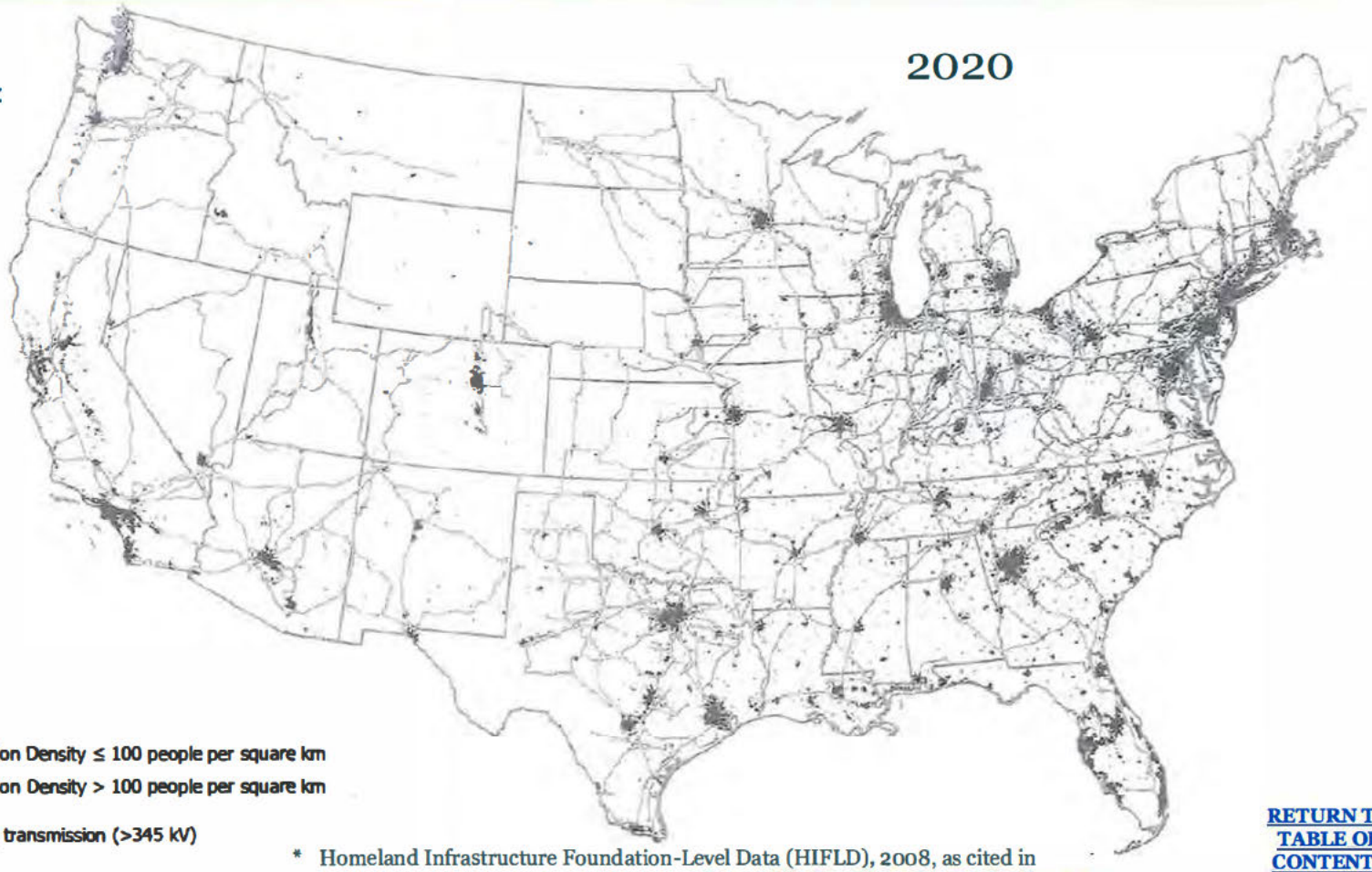
National totals*	TW	2018$ (T)
2020s	0.6	0.8
2030s	1.1	1.3
2040s	1.3	1.3
Total	**3.0**	**3.4**

E+ (Constrained siting)
Cumulative capital invested by decade in solar + wind generation

* National total TW are cumulative capacity built from 2021 – 2050. This differs from capacity in place in 2050 by the amount already in place in 2020, for which no additional investment is required.

Transmission system in 2020 (≥ 345 kV lines shown)

Total transmission capacity:
~320,000 GW-km*



Transmission Capacity (GW)

- 0.002
- 0.002 - 90.123
- 90.123

- 0.002
- 30.0423
- 60.0827
- 90.123

Population Density ≤ 100 people per square km
Population Density > 100 people per square km
Existing transmission (>345 kV)

* Homeland Infrastructure Foundation-Level Data (HIFLD), 2008, as cited in National Renewable Energy Laboratory, Renewable Electricity Futures Study, 2012.

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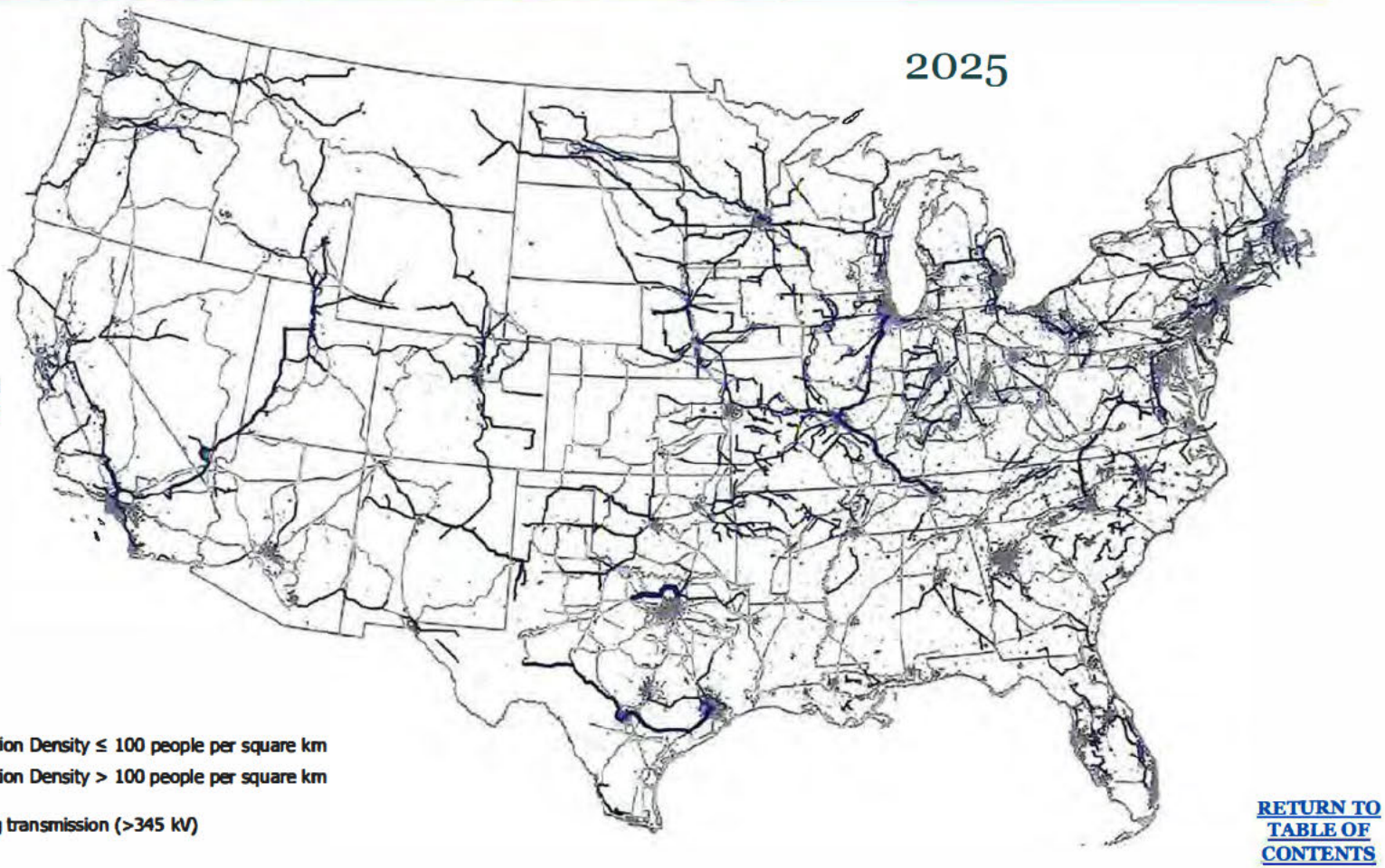
Transmission expansions to support wind and solar generation in E+ scenario with Constrained siting availability, 2025

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 125,600 GW-km (39% increase from 2020)
- capital in service: 240 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



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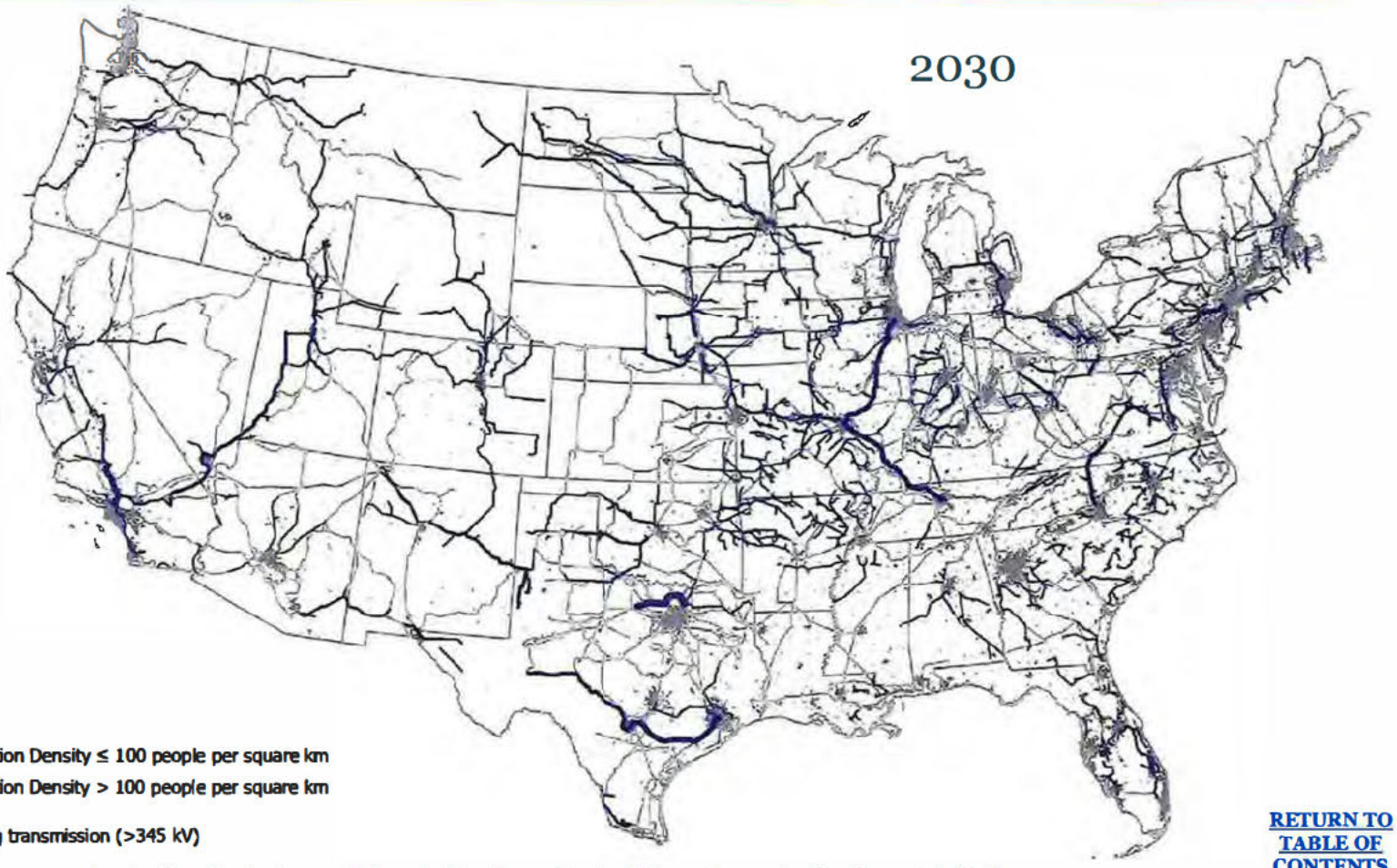
Transmission expansions to support wind and solar generation in E+ scenario with Constrained siting availability, 2030

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 244,500 GW-km (76% increase from 2020)
- capital in service: 530 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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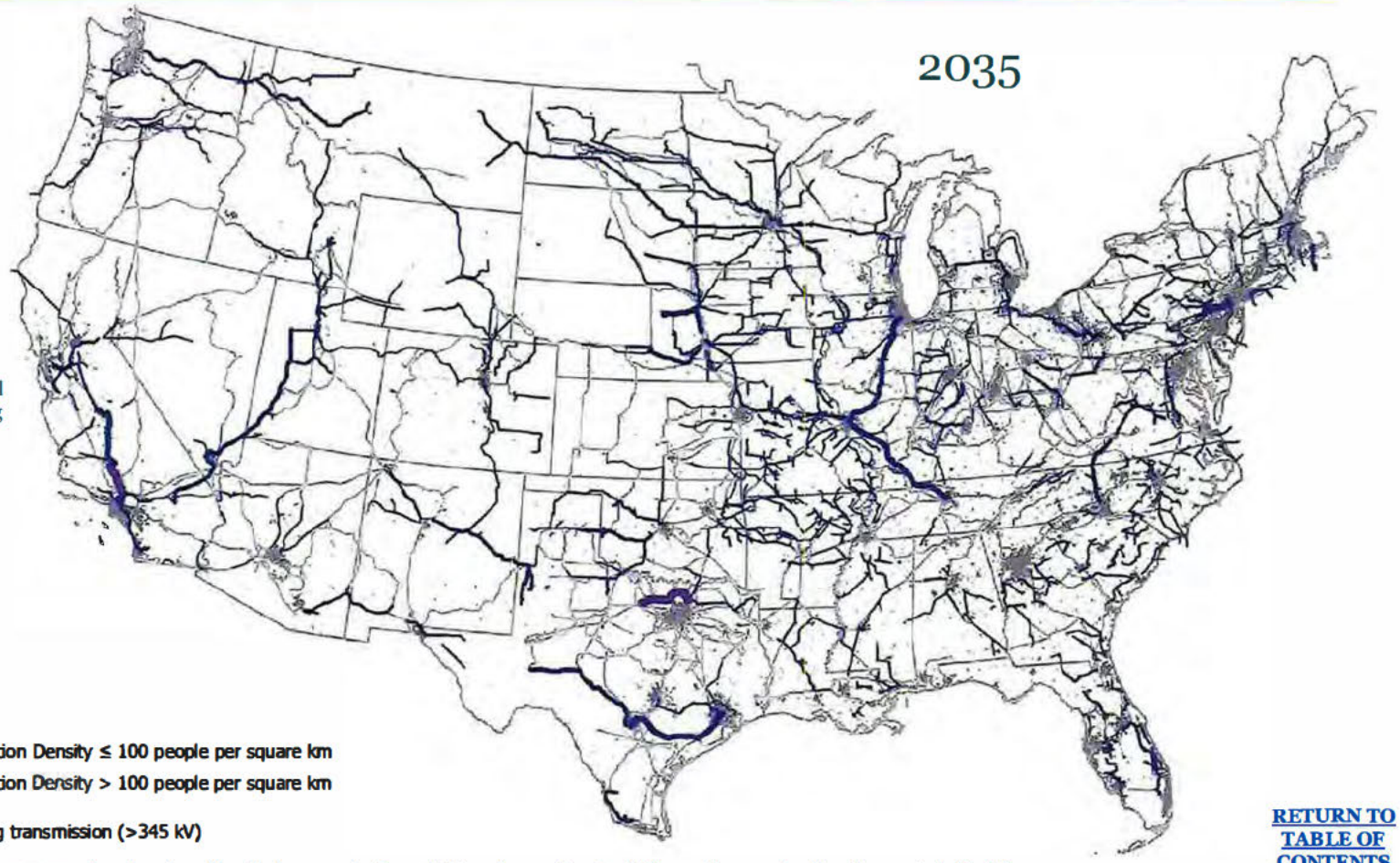
Transmission expansions to support wind and solar generation in E+ scenario with Constrained siting availability, 2035

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 396,800 GW-km (124% increase from 2020)
- capital in service: 910 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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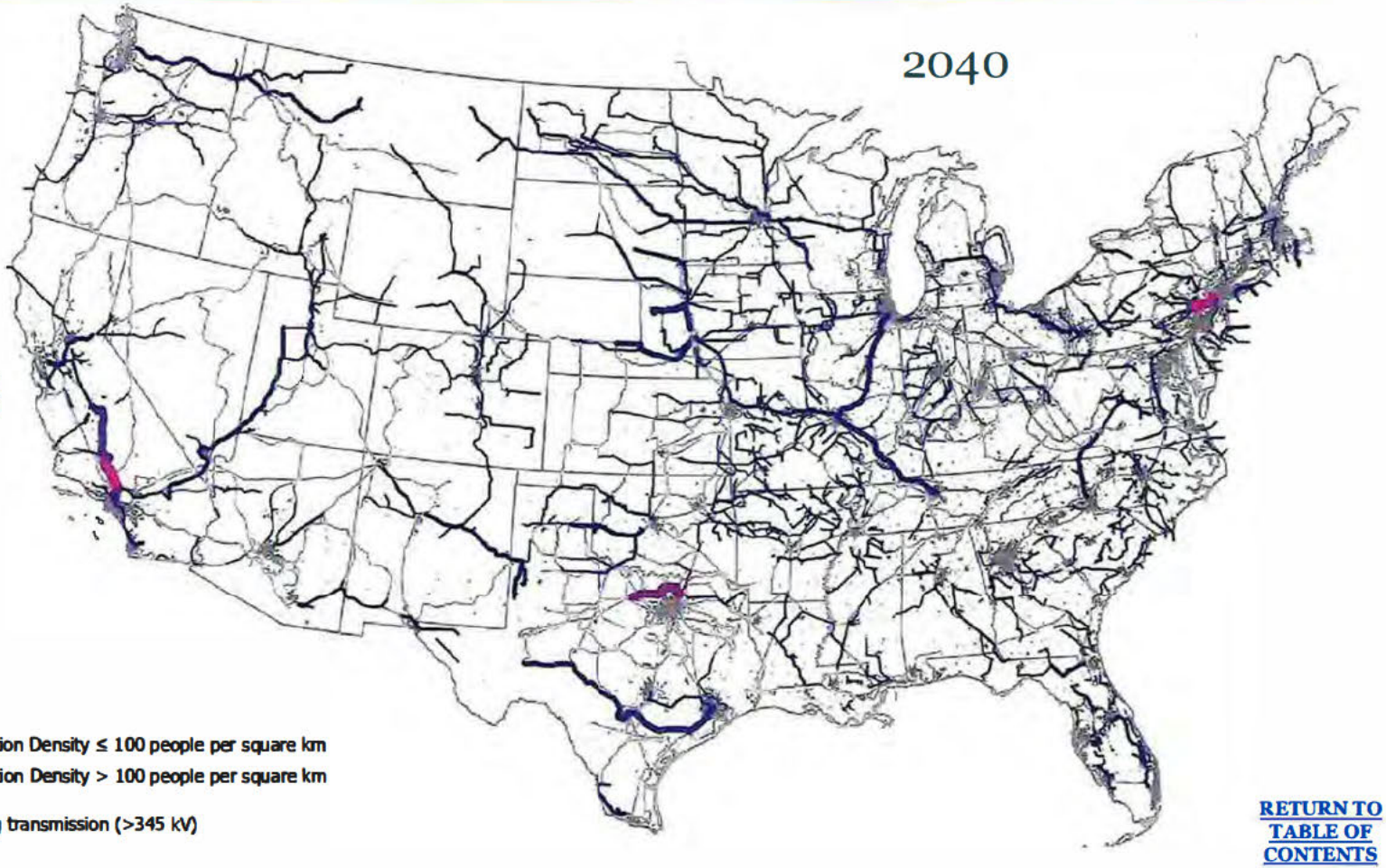
Transmission expansions to support wind and solar generation in E+ scenario with Constrained siting availability, 2040

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 555,900 GW-km (174% increase from 2020)
- capital in service: 1,370 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



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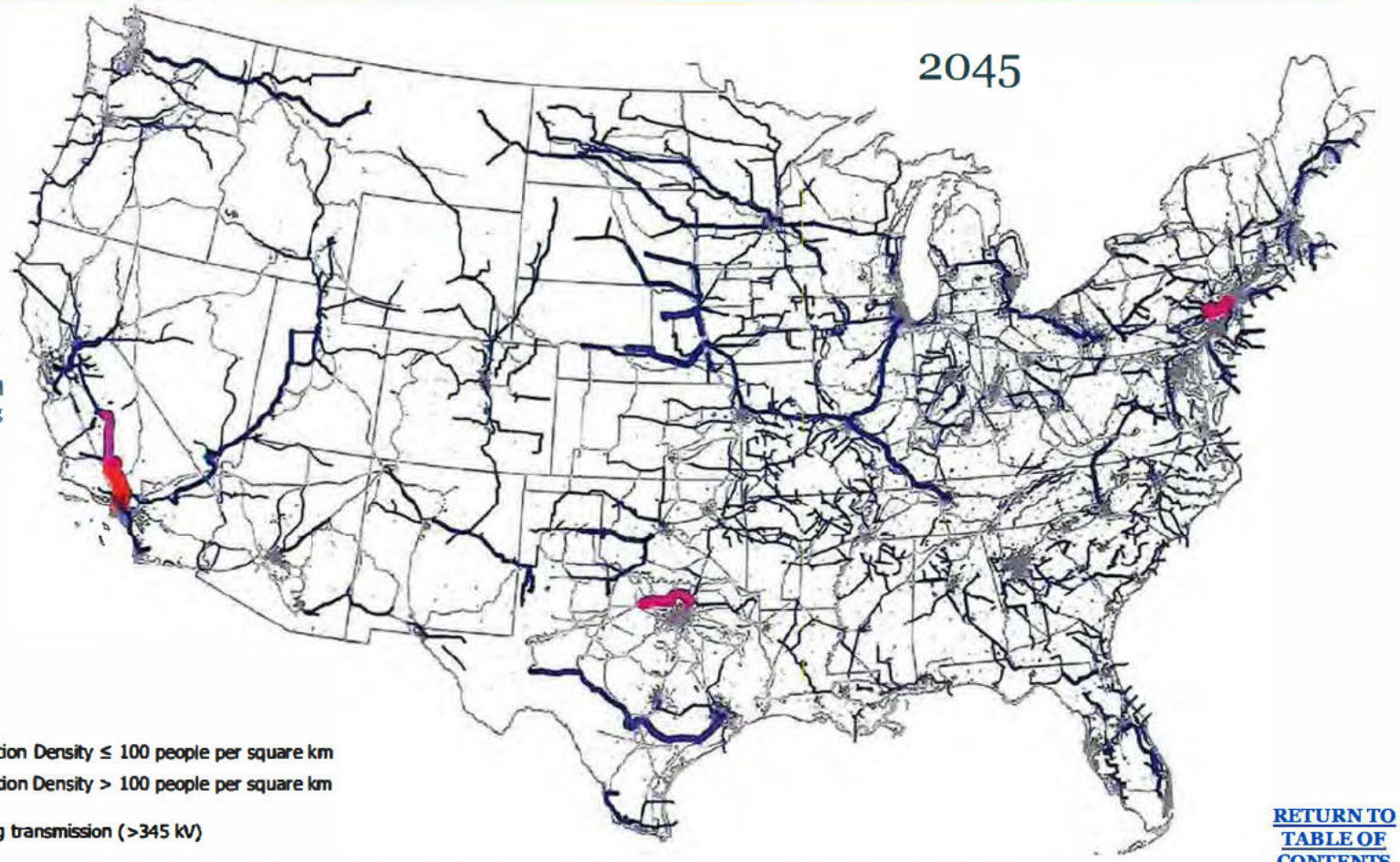
Transmission expansions to support wind and solar generation in E+ scenario with Constrained siting availability, 2045

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 769,600 GW-km (241% increase from 2020)
- capital in service: 2,040 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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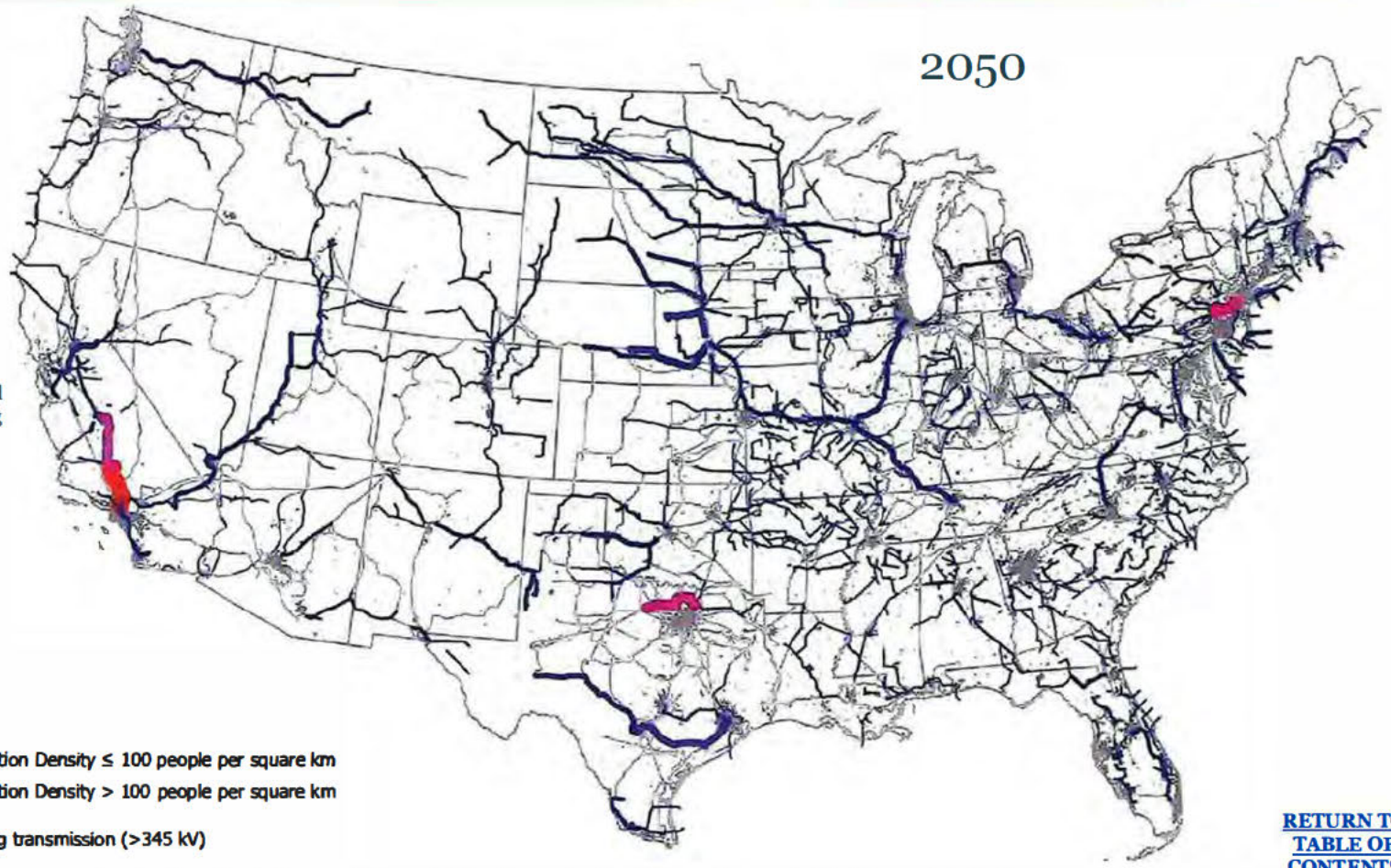
Transmission expansions to support wind and solar generation in E+ scenario with Constrained siting availability, 2050

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 795,200 GW-km (249% increase from 2020)
- capital in service: 2,540 B$

Note: Capital in service includes both capital for transmission expansions and "sustaining capital" (for end-of-life line replacements.)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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E+ with Constrained site availability requires more transmission; total transmission capacity in 2050 is **3.5x** current capacity.

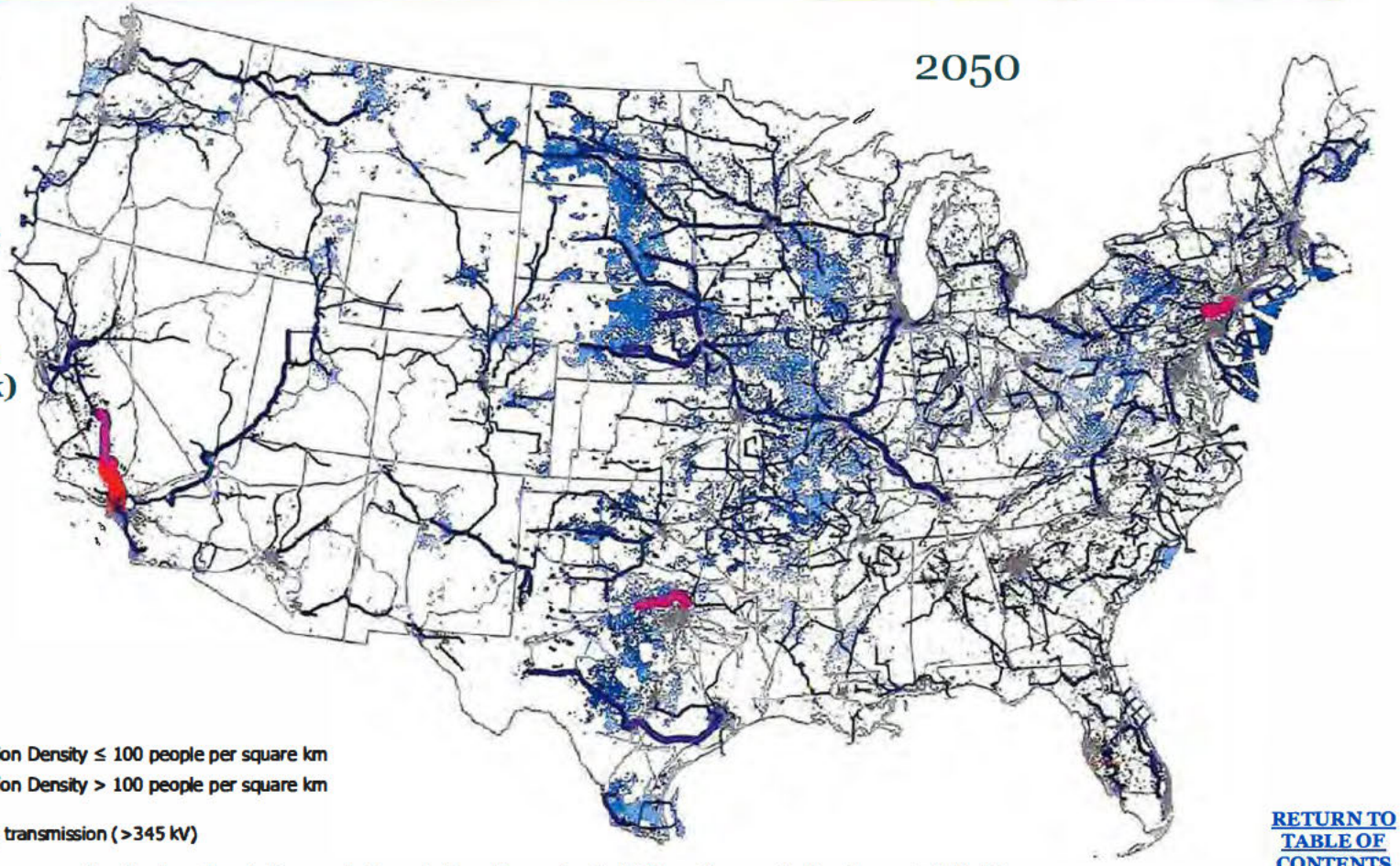


Transmission & generators.

Note: Capacity factors at generator sites are reflected in color intensity, with highest CF = darkest color.

2020 transmission capacity:
~320,000 GW-km

2050 transmission capacity:
~1,115,000 GW-km (3.5x)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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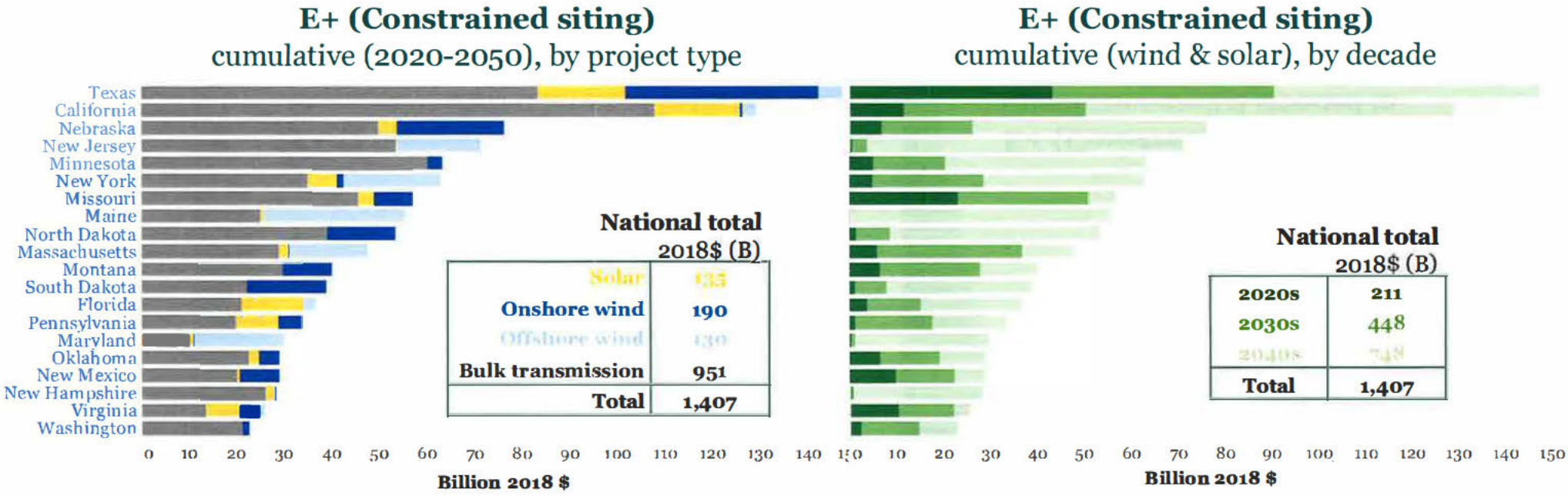
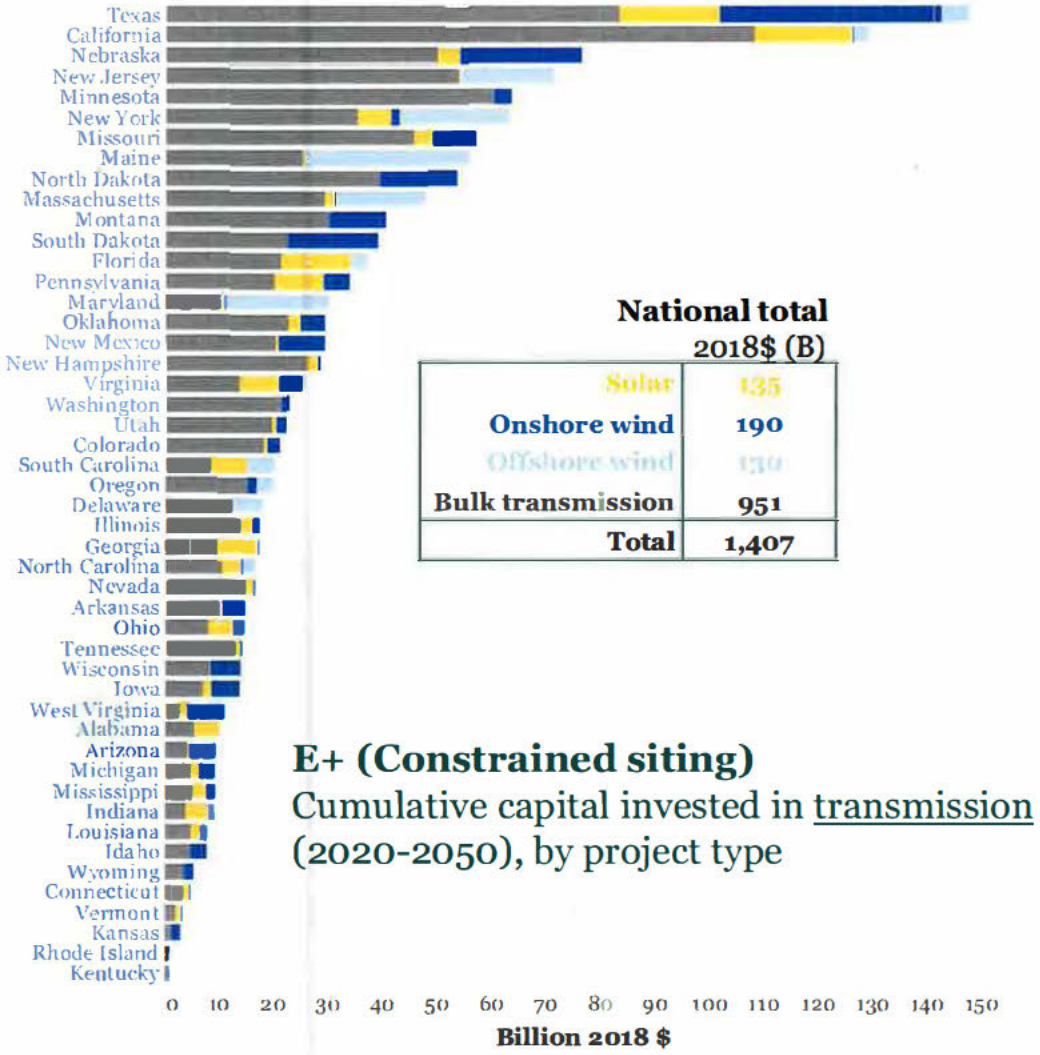
Capital investment in transmission, top-ranked states





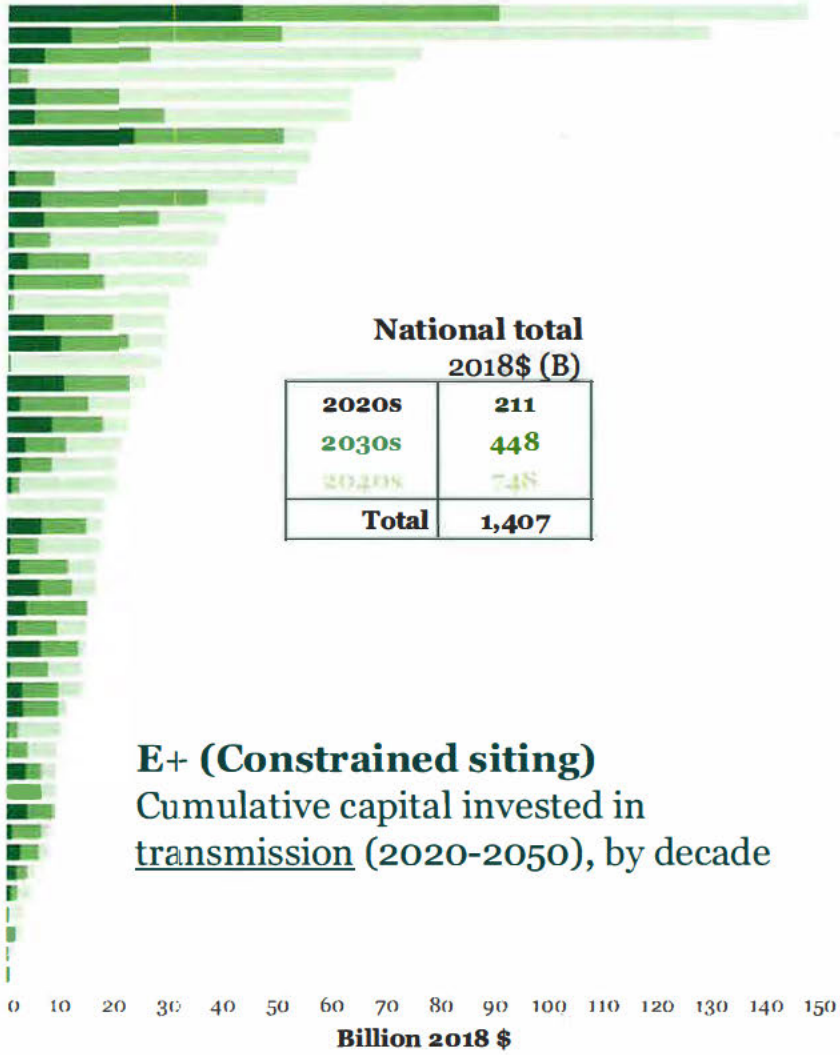
Note: These capital estimates are for transmission expansions. The values labeled solar, onshore wind, and offshore wind are spur lines from solar or wind projects to nearest substations. Sustaining capital invested for end-of-life line replacements is not included here, but is included in transmission capital investment estimates in the capital mobilization section of this report.



National total
2018$ (B)

Solar	135
Onshore wind	**190**
Offshore wind	130
Bulk transmission	**951**
Total	**1,407**

E+ (Constrained siting)
Cumulative capital invested in transmission (2020-2050), by project type



National total
2018$ (B)

2020s	**211**
2030s	**448**
2040s	748
Total	**1,407**

E+ (Constrained siting)
Cumulative capital invested in transmission (2020-2050), by decade

Note: These capital estimates are for transmission expansions. The values labeled solar, onshore wind, and offshore wind are spur lines from solar or wind projects to nearest substations. Sustaining capital invested for end-of-life line replacements is not included in the totals here, but is included in transmission capital investment estimates in the capital mobilization section of this report.

Mapping solar and wind generators and transmission for the E+ RE+ pathway



Summary of this section

- The E+ RE+ case relies exclusively on renewable energy by 2050, and requires 5.7 TW of wind and solar capacity to meet economy-wide demands (nearly double the capacity in the E+ case). This represents $6.2 trillion of investment.
- The ranking of top 10 solar states are unaffected relative to Base land availability.
- Wind and solar farms span a total area of more than 1 million km²; wind farms account for 94% of this and may have extensive visual impact on nearby communities.
- Offshore wind farms span another 64,000 km² and are built extensively along the entire Atlantic Coast, as well as some areas in the Gulf of Mexico and floating turbines on the Pacific coast.
- Lands directly impacted by onshore wind and solar farms (e.g. with roads, turbine pads, solar arrays, inverters, and substations) totals ~70,000 km².
- Transmission capacity expands ~78% by 2030 and 5.3x through 2050 (over 1.7 million GW-km, or ~70% more transmission expansion than the E+ case).
- Total capital invested in transmission is ~$390b through 2030 and $3.7 trillion by 2050.
- The footprint of wind and solar in RE+ are extensive and will require broad-based and sustained support from communities across much of the nation.
- A more restrictive permitting regime which constrains the available sites for development leads to more dispersed wind and solar development and increased transmission requirements, and significant regional shortfalls in both offshore and onshore wind sites.

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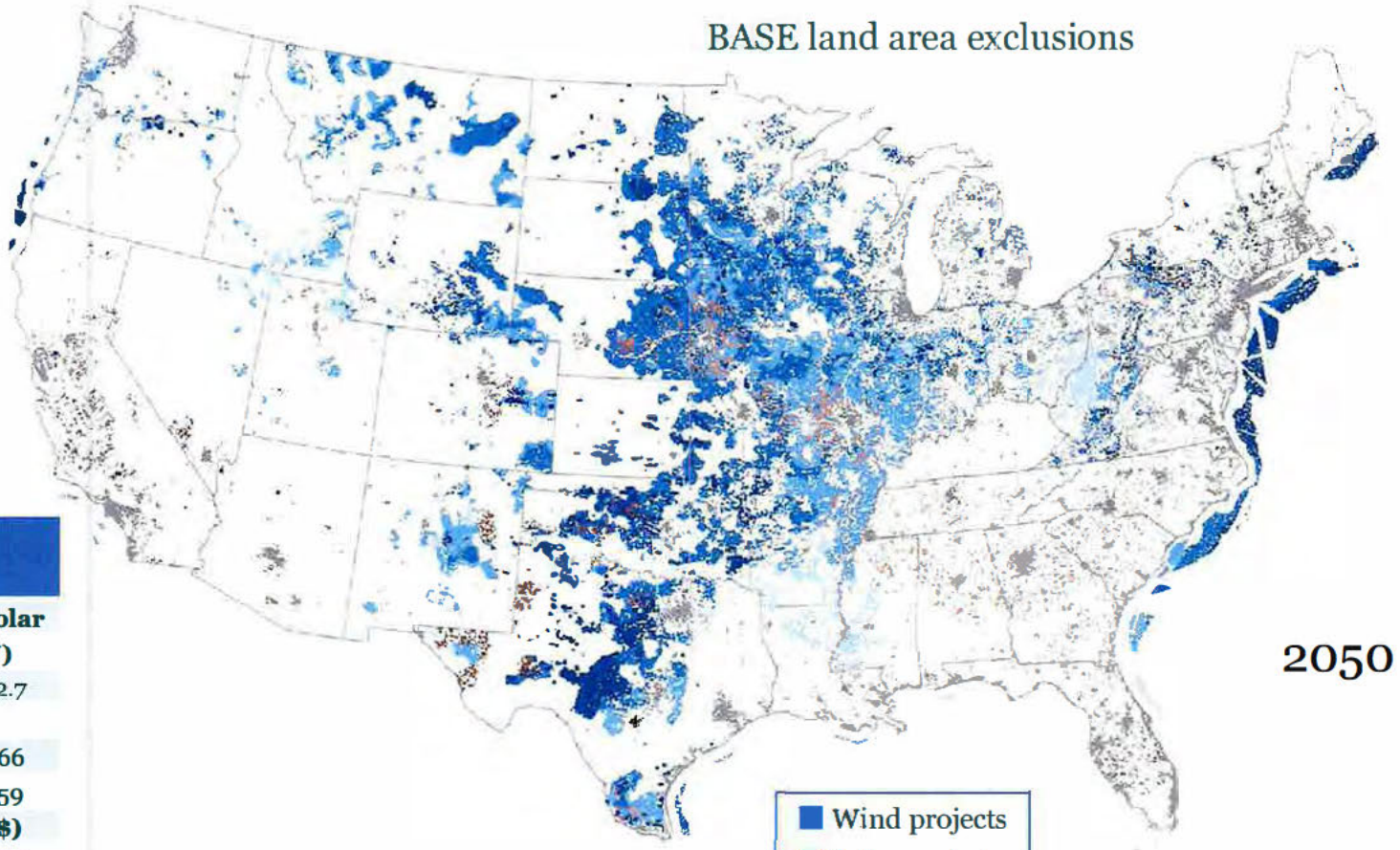
2050 build out of wind and solar projects, RE+ Base





2020 - 2050 (cumulative)	Wind	Solar
Capacity installed (TW)		
	3.0	2.7
Land used (1000 km²)		
Total	1009	66
Direct	10.1	59
Capital invested (2018$)		
Trillion $	3.8	2.2

Note: Site capacity factors are reflected in color intensity (highest CF = darkest color).

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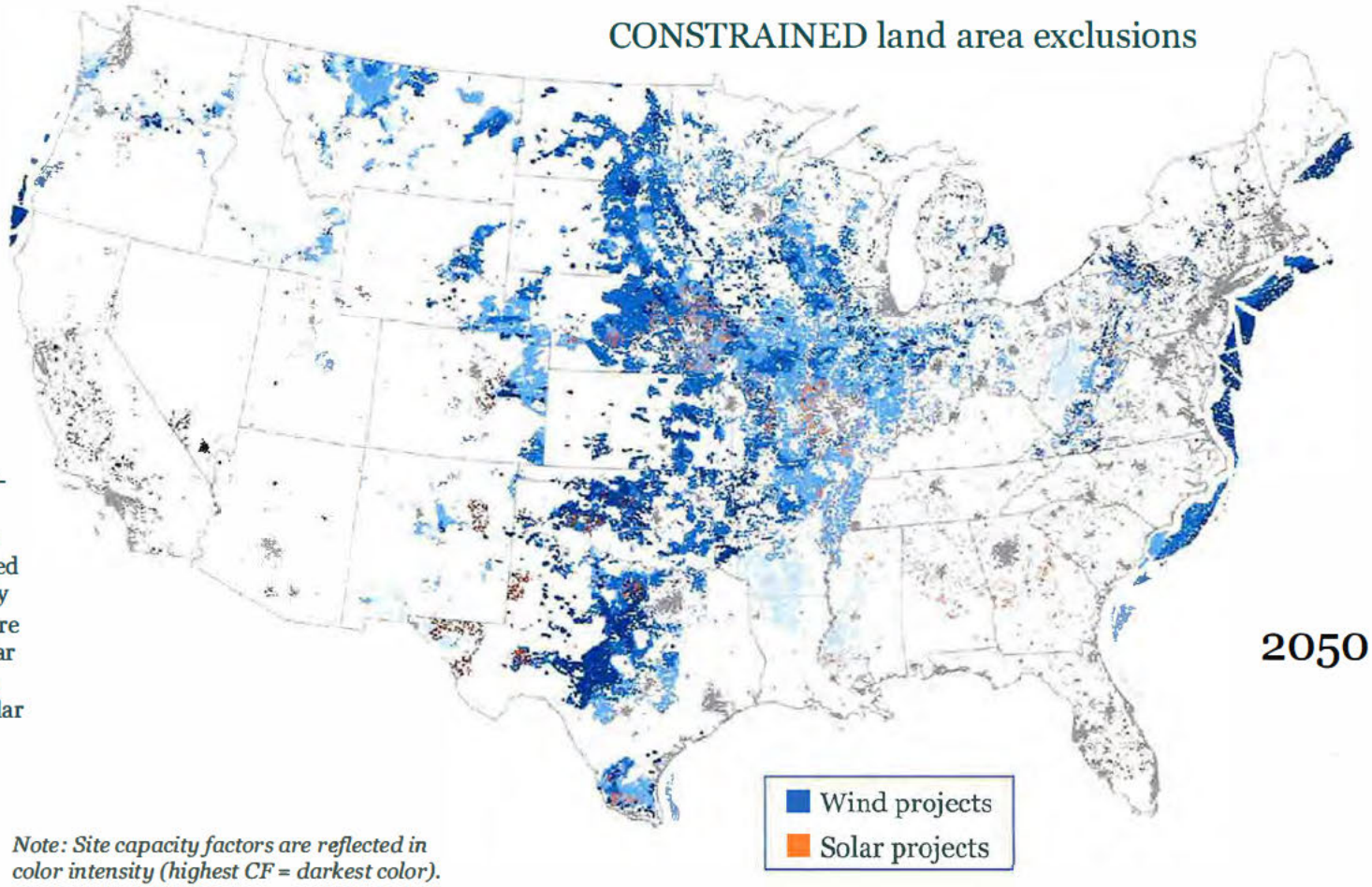
2050 build out of wind and solar projects, RE+ Constrained*



* With Constrained site availability, there were insufficient candidate project sites for wind (on- and off-shore) in some regions. Additional sites were allowed to be selected from Base site-availability areas in those cases. There were also insufficient solar candidate project sites in some regions, and a similar allowance was made.

Note: Site capacity factors are reflected in color intensity (highest CF = darkest color).

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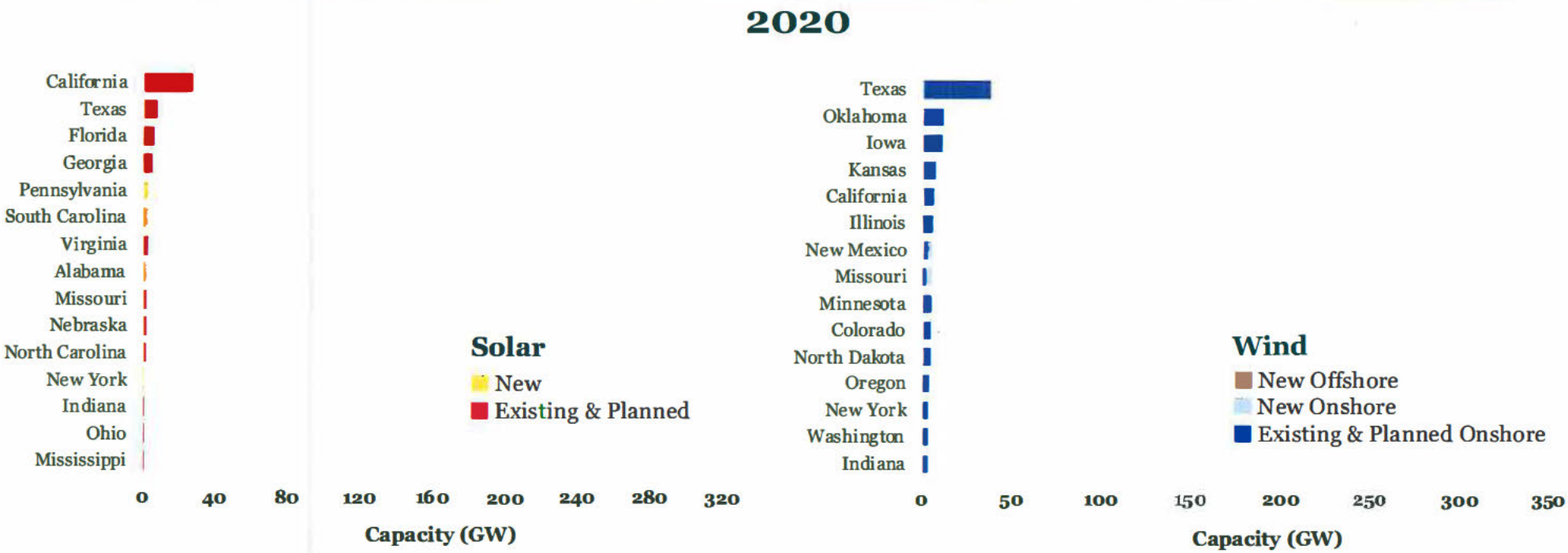
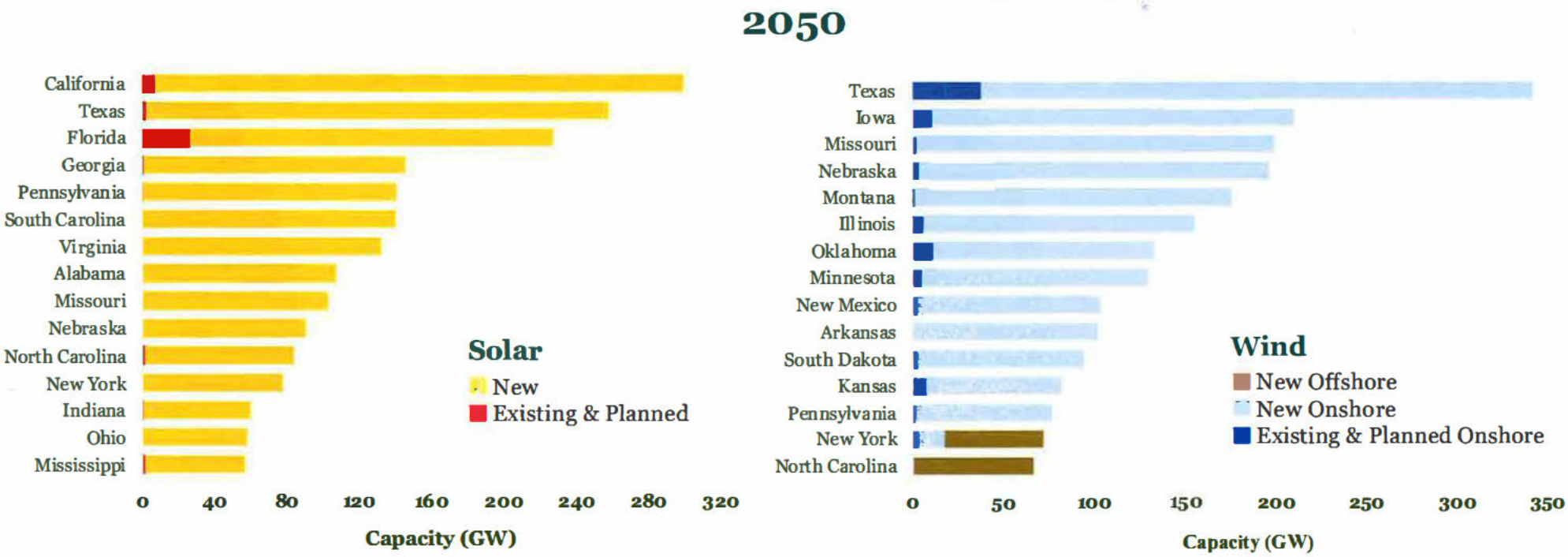
Installed solar and wind capacity, top-ranked states, E+ RE+ Base





Installed solar and wind capacity, top-ranked states, E+ RE+ Base

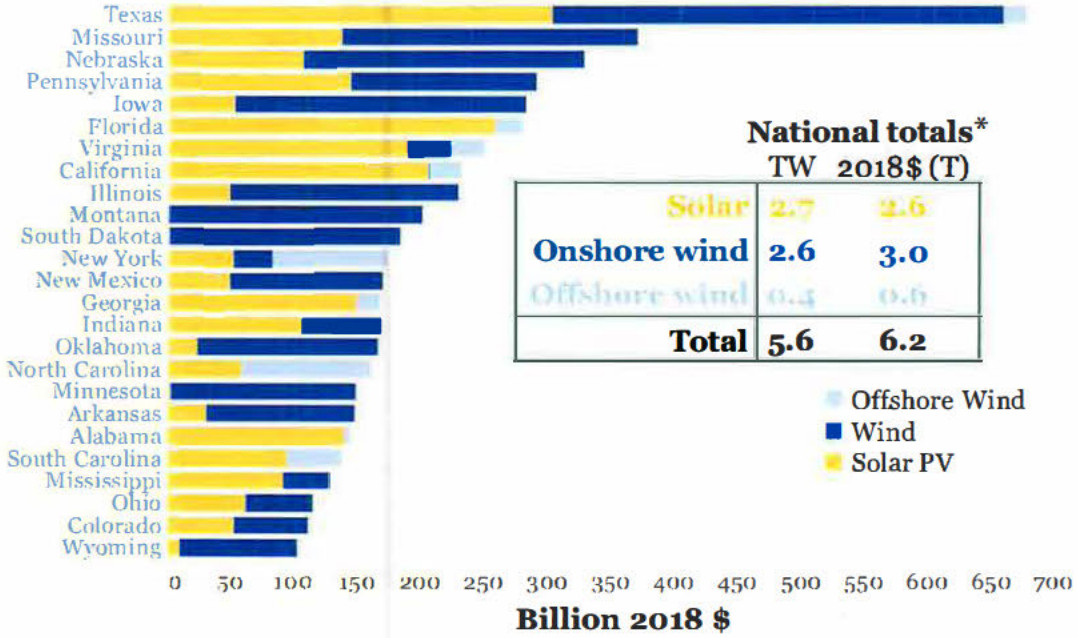




Capital investment in solar and wind generating projects, top-ranked states



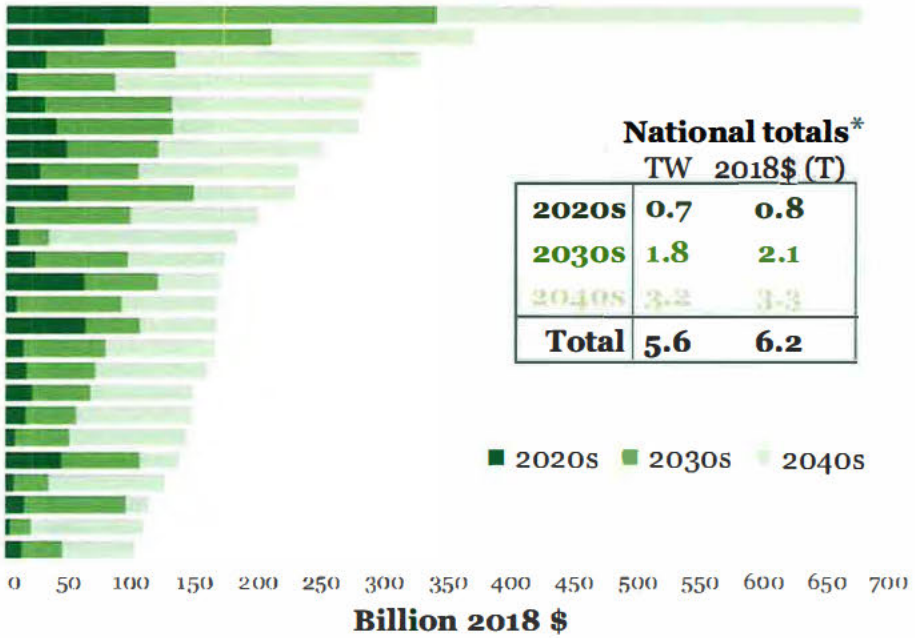
E+ RE+ (Base siting)
cumulative (2021-2050), by project type



National totals*

	TW	2018$ (T)
Solar	2.7	2.6
Onshore wind	2.6	3.0
Offshore wind	0.4	0.6
Total	**5.6**	**6.2**

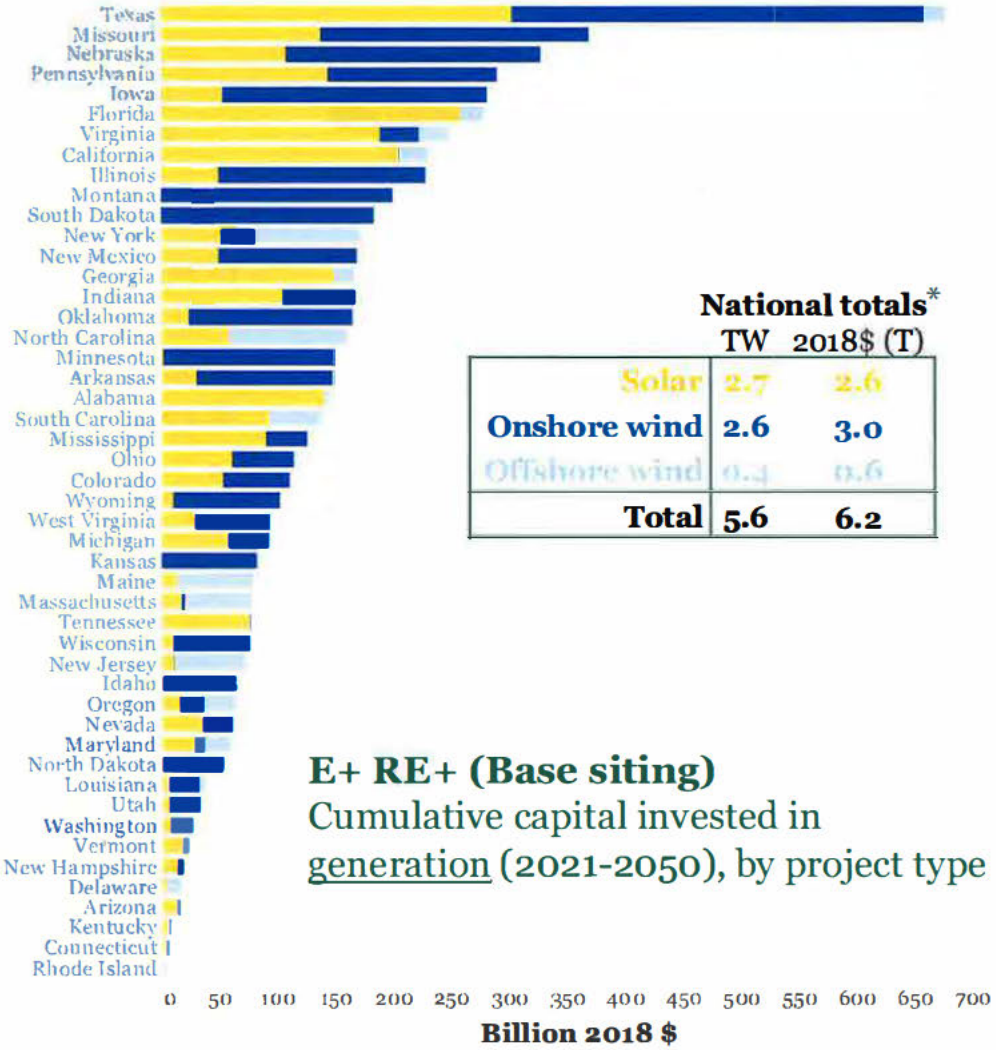
E+ RE+ (Base siting)
cumulative (wind & solar), by decade



National totals*

	TW	2018$ (T)
2020s	0.7	0.8
2030s	1.8	2.1
2040s	3.2	3.3
Total	**5.6**	**6.2**

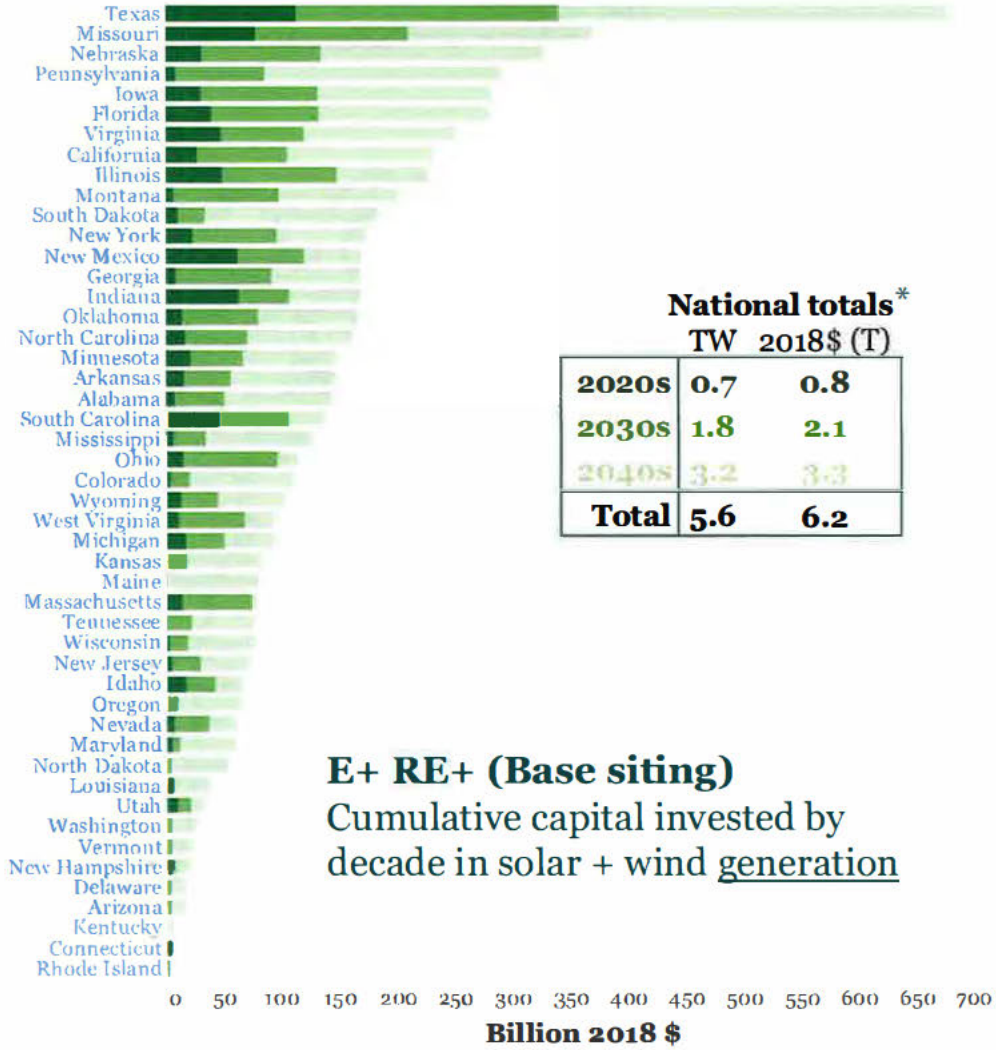
* National total TW are cumulative capacity built from 2021 – 2050. This differs from capacity in place in 2050 by the amount already in place in 2020, for which no additional investment is required.



National totals*

	TW	2018$ (T)
Solar	2.7	2.6
Onshore wind	2.6	3.0
Offshore wind	0.4	0.6
Total	**5.6**	**6.2**

E+ RE+ (Base siting)
Cumulative capital invested in generation (2021-2050), by project type



National totals*

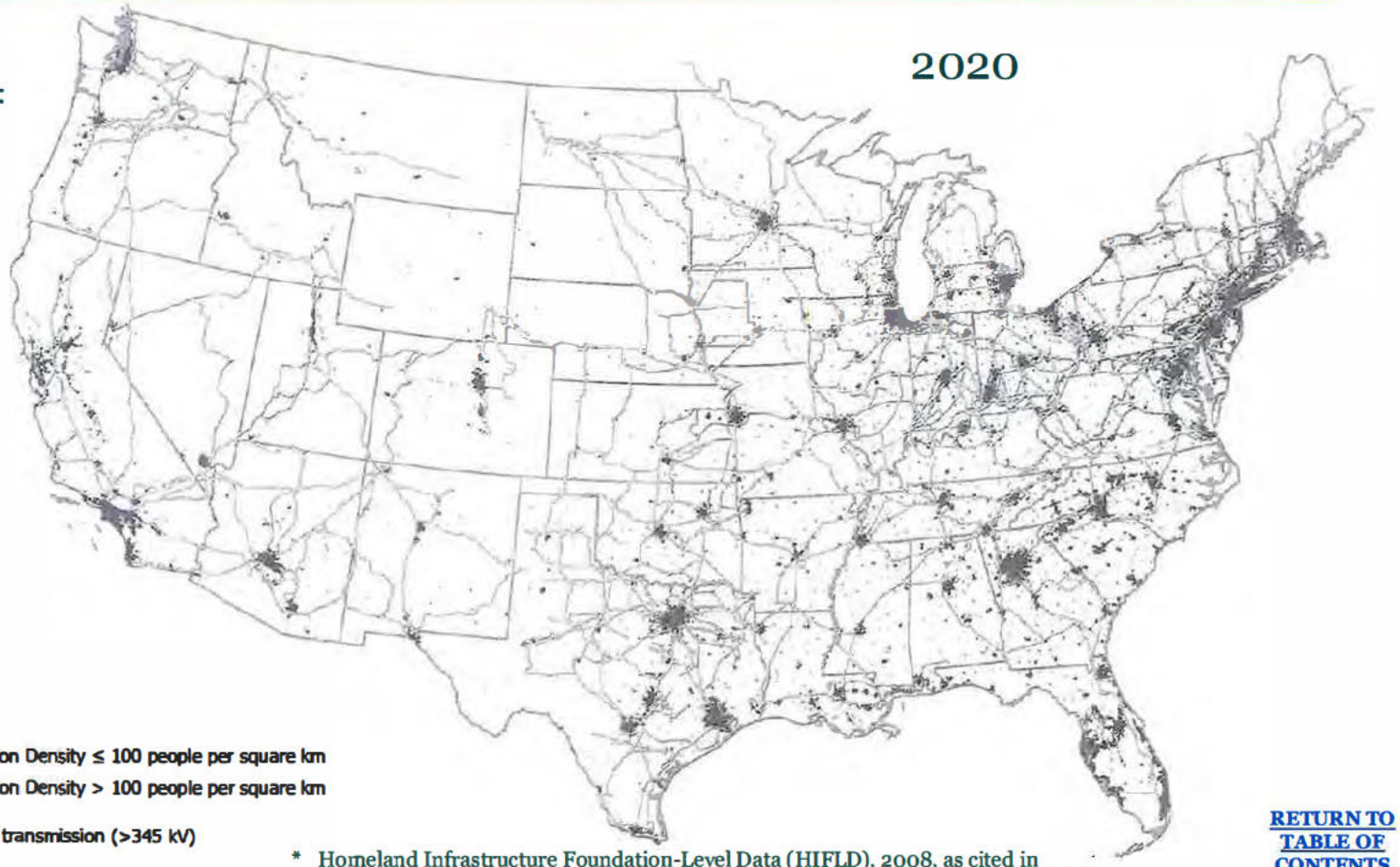
	TW	2018$ (T)
2020s	0.7	0.8
2030s	1.8	2.1
2040s	3.2	3.3
Total	**5.6**	**6.2**

E+ RE+ (Base siting)
Cumulative capital invested by decade in solar + wind generation

* National total TW are cumulative capacity built from 2021 – 2050. This differs from capacity in place in 2050 by the amount already in place in 2020, for which no additional investment is required.

Transmission system in 2020 (≥ 345 kV lines shown)

Total transmission capacity:
~320,000 GW-km*



* Homeland Infrastructure Foundation-Level Data (HIFLD), 2008, as cited in National Renewable Energy Laboratory, Renewable Electricity Futures Study, 2012.

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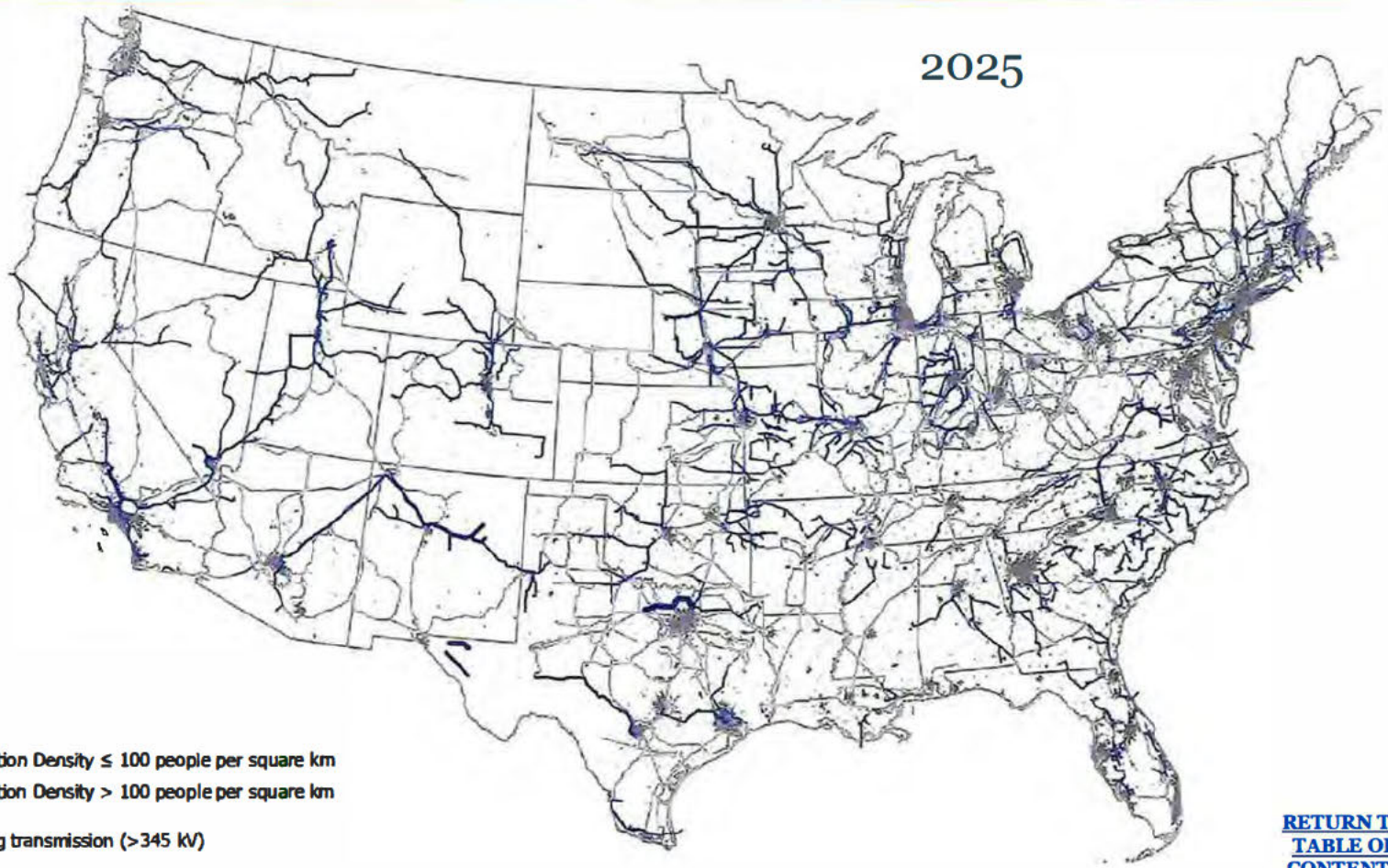
Transmission expansions to support wind and solar generation in E+ RE+ scenario with Base siting availability, 2025

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 99,700 GW-km (31% increase from 2020)
- capital invested: 160 B$



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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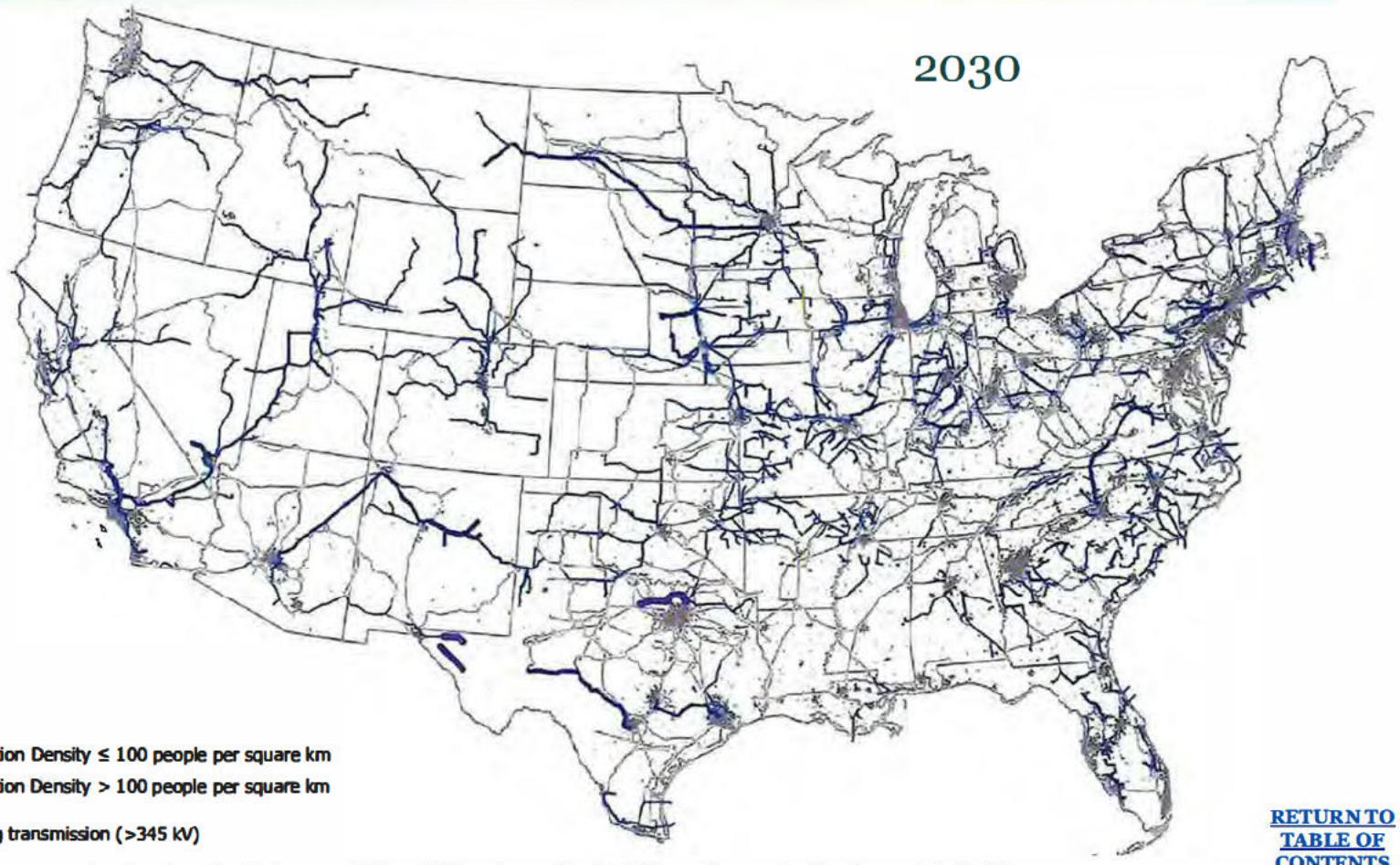
Transmission expansions to support wind and solar generation in E+ RE+ scenario with Base siting availability, 2030

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 250,200 GW-km (78% increase from 2020)
- capital invested: 390 B$



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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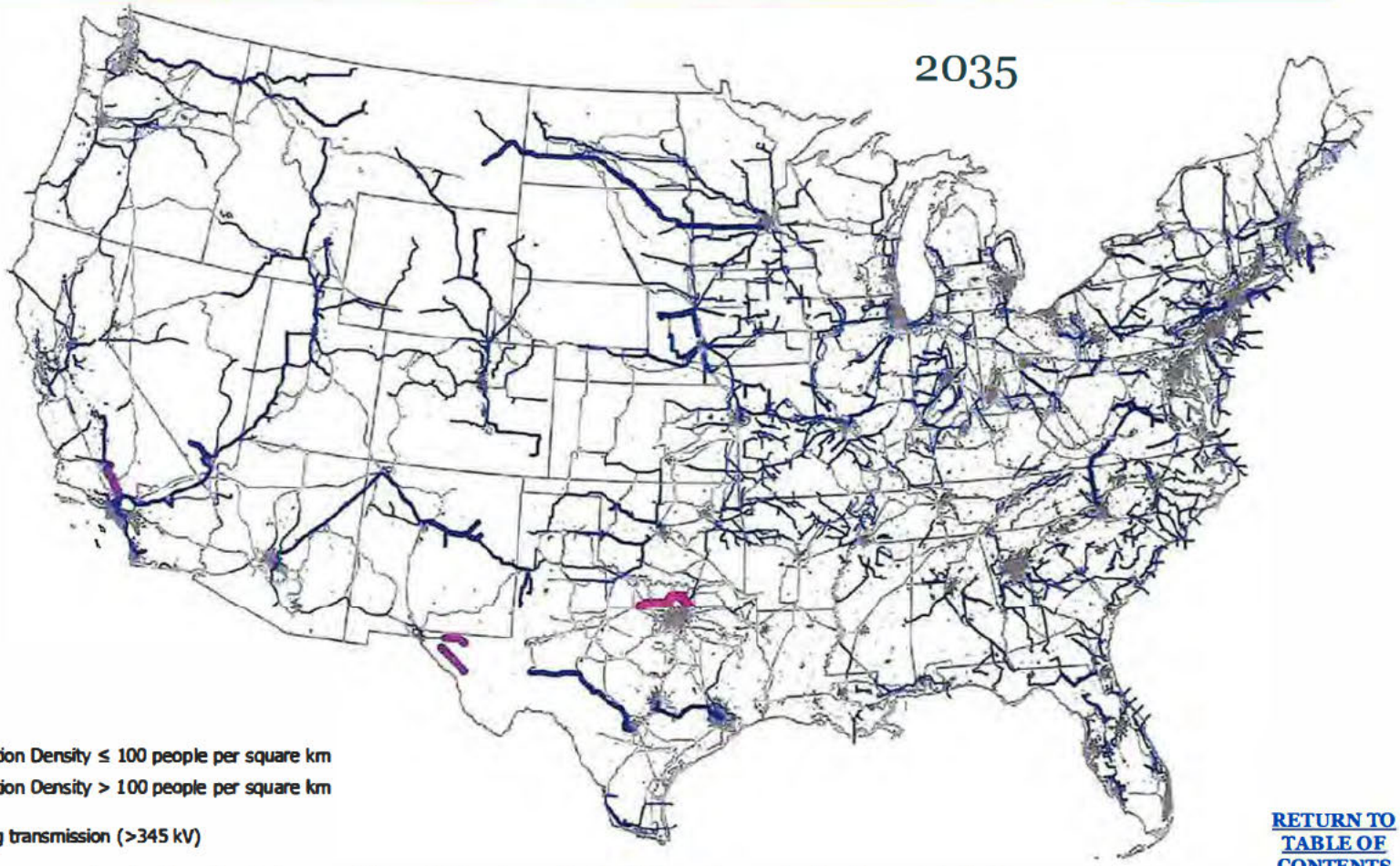
Transmission expansions to support wind and solar generation in E+ RE+ scenario with Base siting availability, 2035

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 482,200 GW-km (151% increase from 2020)
- capital invested: 780 B$



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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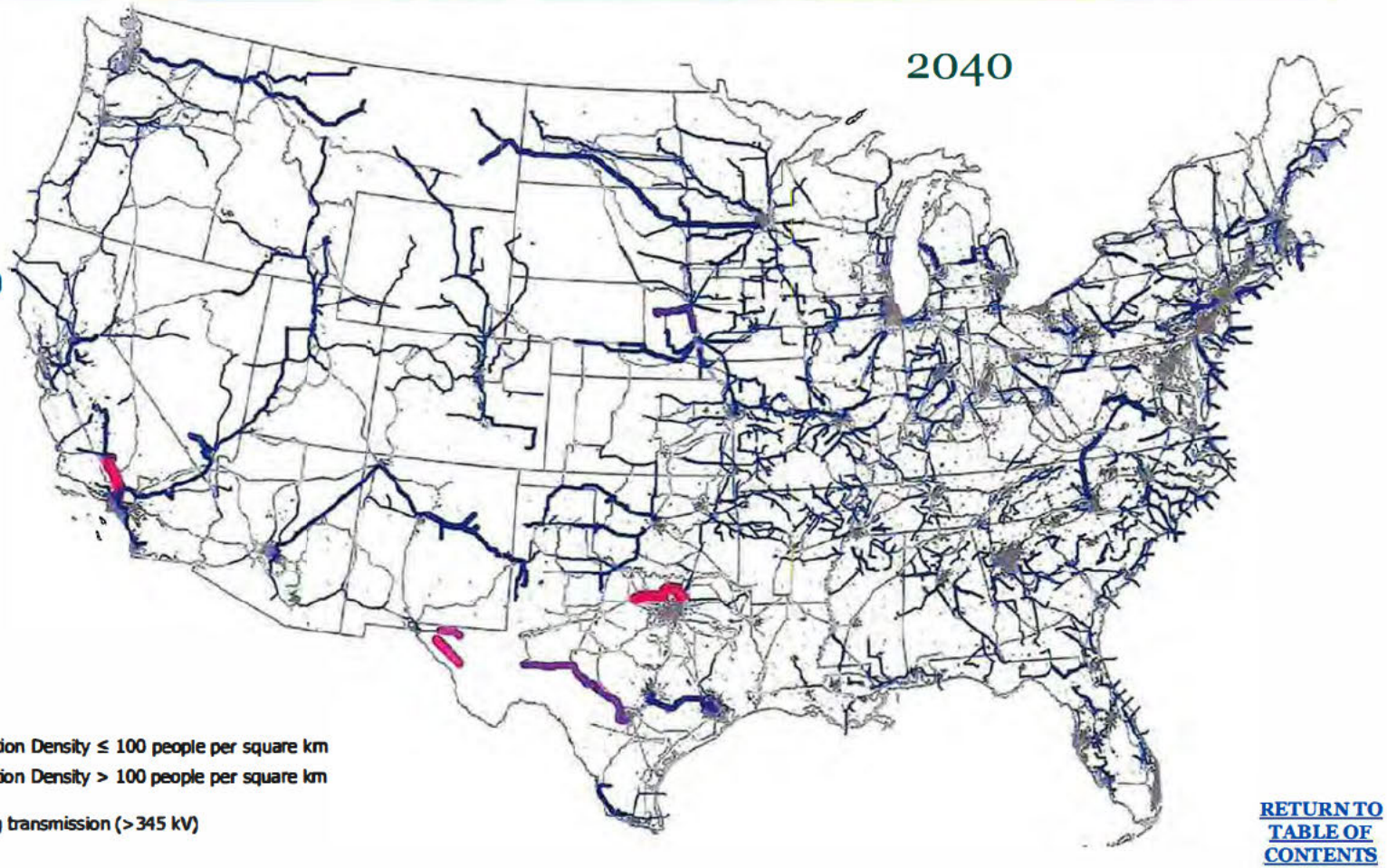
Transmission expansions to support wind and solar generation in E+ RE+ scenario with Base siting availability, 2040

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 805,700 GW-km (252% increase from 2020)
- capital invested: 1,370 B$



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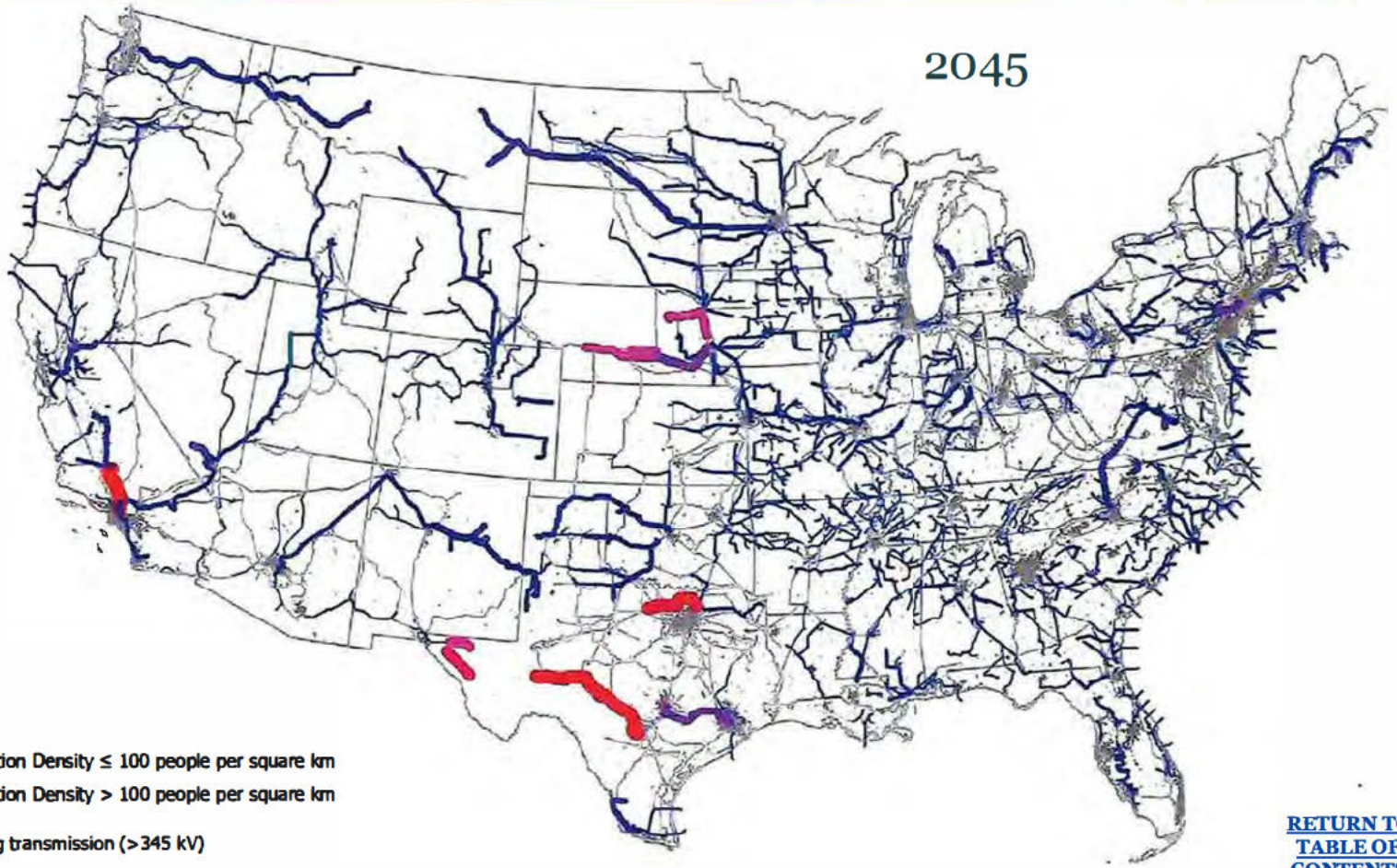
Transmission expansions to support wind and solar generation in E+ RE+ scenario with Base siting availability, 2045

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 1,304,300 GW-km (408% increase over 2020)
- capital invested: 2,270 B$



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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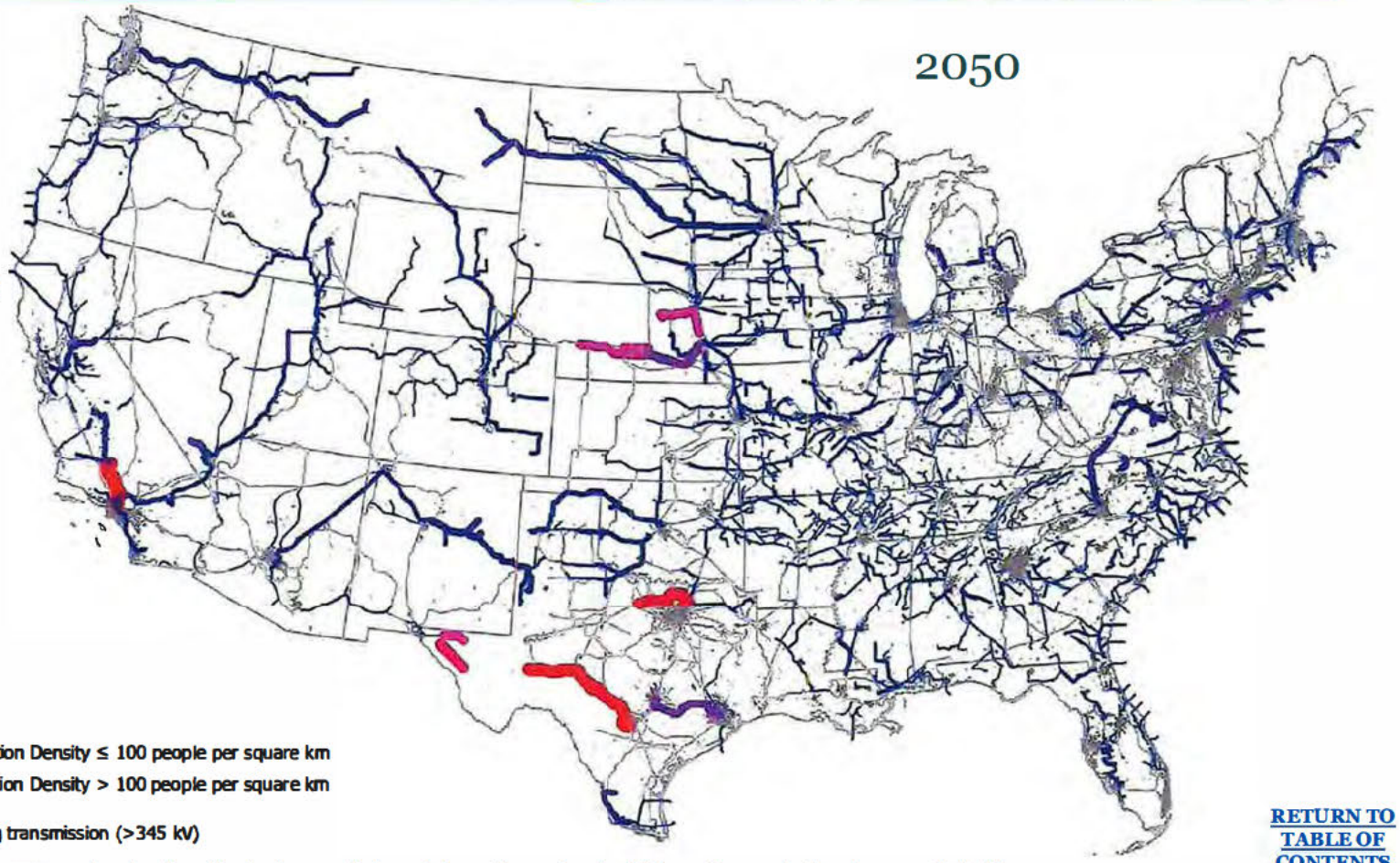
Transmission expansions to support wind and solar generation in E+ RE+ scenario with Base siting availabili ty, 2050

Spur lines from solar and wind projects to substations are not shown, but are included in investment and GW-km build totals:

Cumulative
- build: 1,382,100 GW-km (432% increase from 2020)
- capital invested: 3,710 B$



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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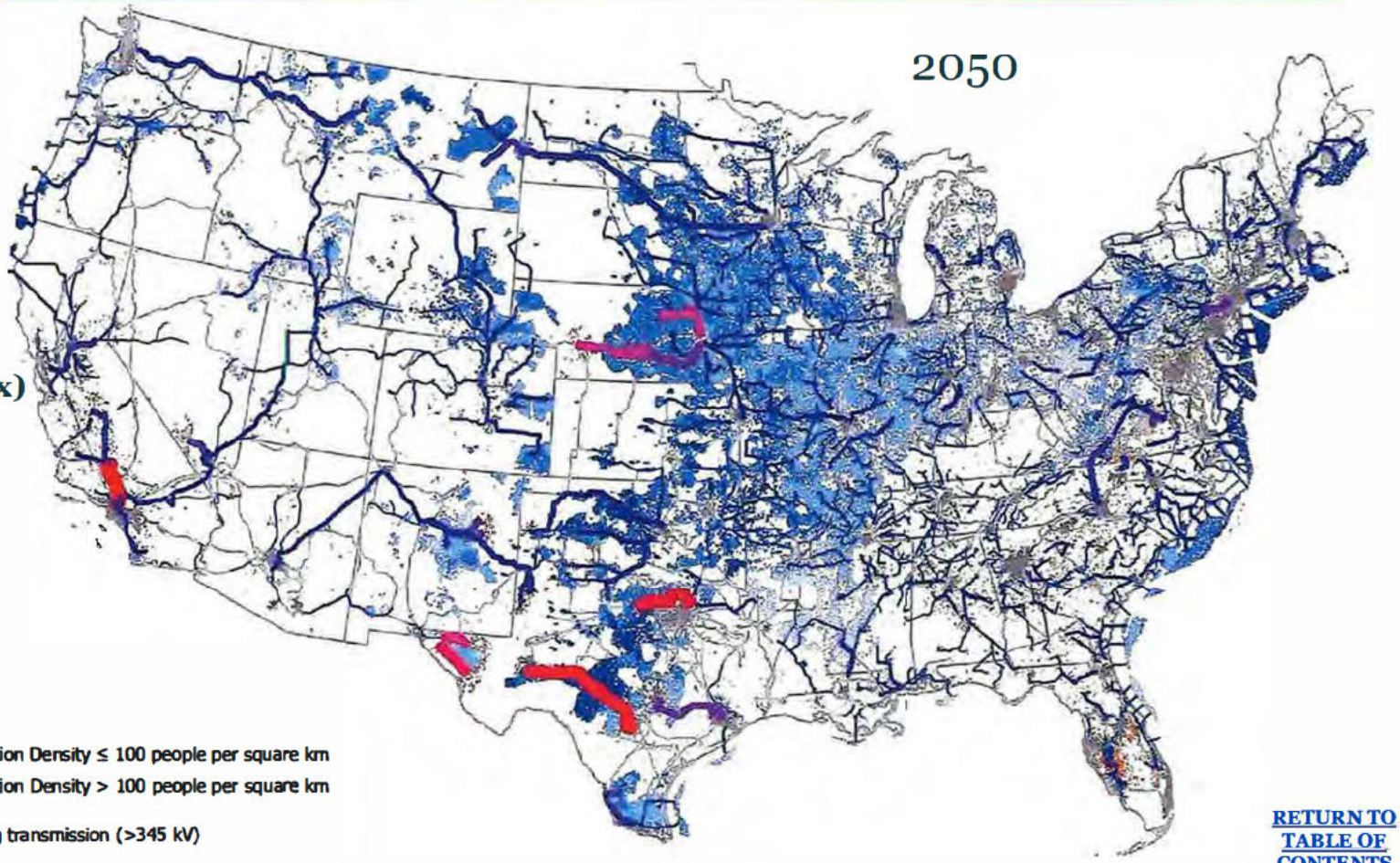
To support wind and solar generation in E+RE+ scenario with Base siting availability, total U.S. transmission capacity increases **5.3x**.

Transmission & generators.

Note: Capacity factors at generator sites are reflected in color intensity, with highest CF = darkest color.

2020 transmission capacity:
~320,000 GW-km

2050 transmission capacity:
~1,702,000 GW-km (5.3x)



Note: Transmission expansion is visualized along existing rights of way (>160 kV); paths are indicative not definitive.

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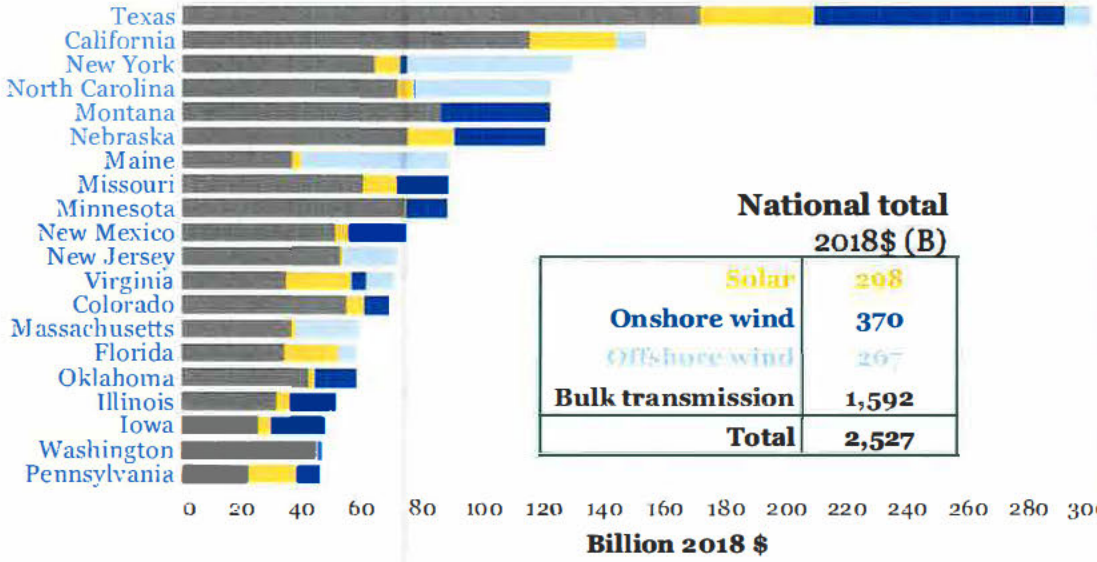
Capital investment in transmission, top-ranked states



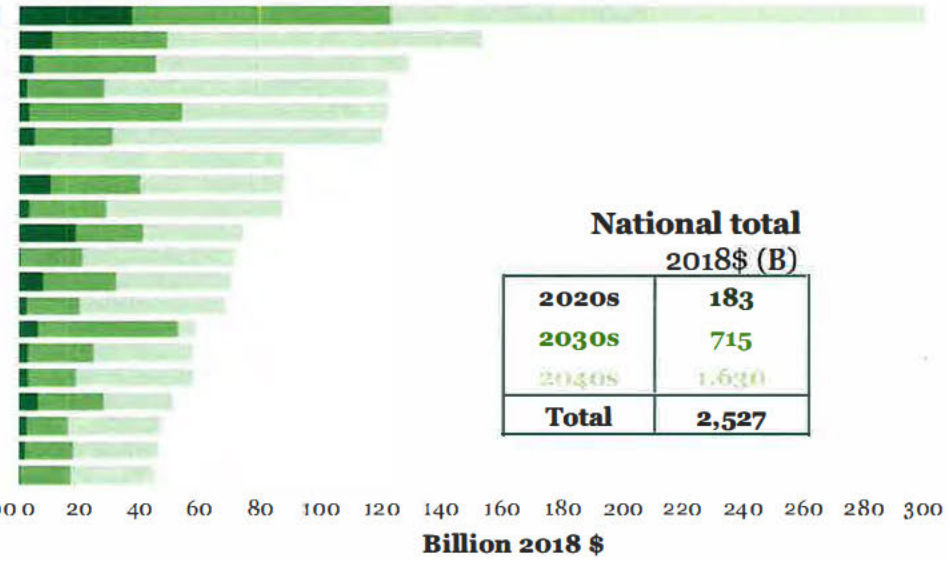
E+ RE+ (Base siting)
cumulative (2020-2050), by project type



National total
2018$ (B)

Solar	208
Onshore wind	370
Offshore wind	267
Bulk transmission	1,592
Total	2,527

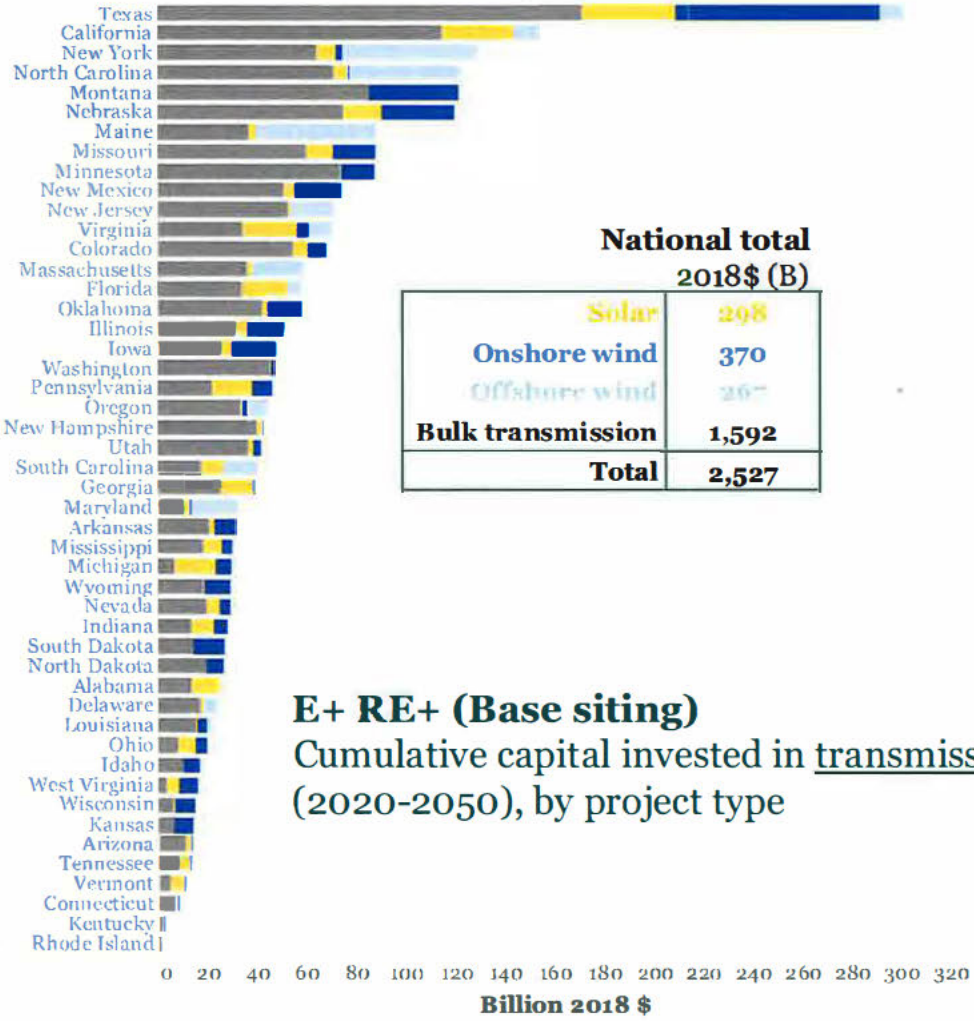
E+ RE+ (Base siting)
cumulative (wind & solar), by decade



National total
2018$ (B)

2020s	183
2030s	715
2040s	1,630
Total	2,527

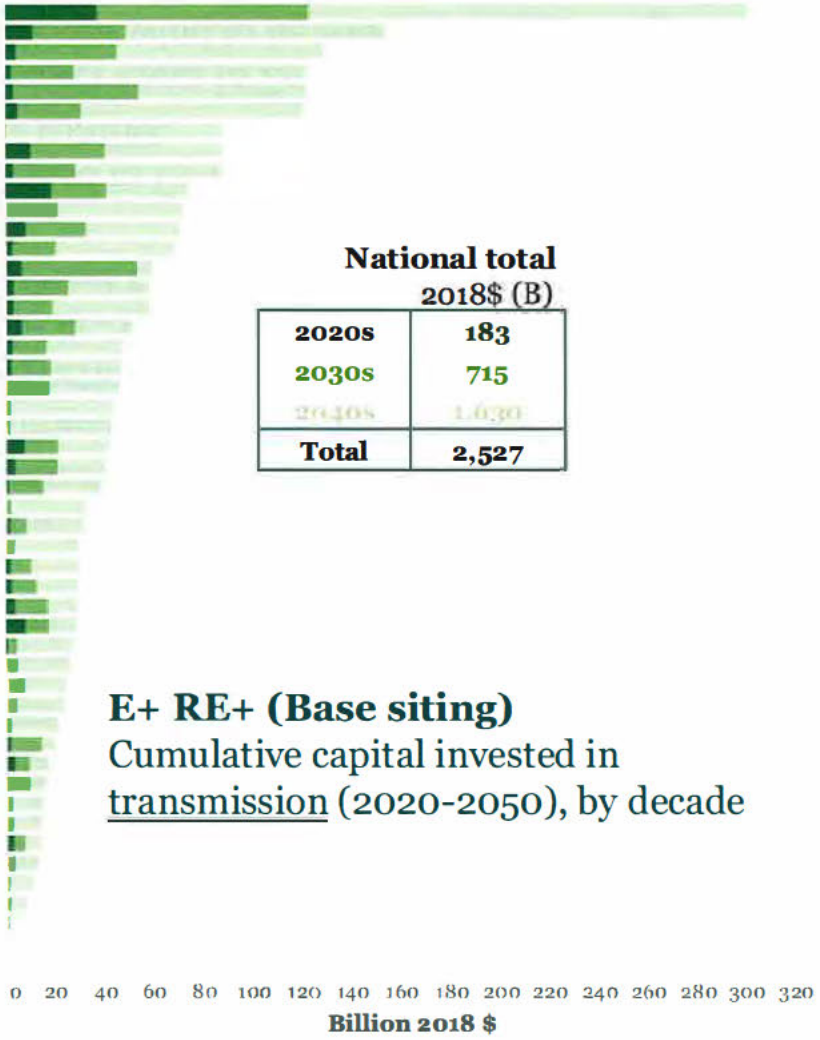
Note: These capital estimates are for transmission expansions. The values labeled solar, onshore wind, and offshore wind are spur lines from solar or wind projects to nearest substations. Sustaining capital invested for end-of-life line replacements is not included here, but is included in transmission capital investment estimates in the capital mobilization section of this report.



National total
2018$ (B)

Solar	298
Onshore wind	370
Offshore wind	267
Bulk transmission	**1,592**
Total	**2,527**

E+ RE+ (Base siting)
Cumulative capital invested in transmission (2020-2050), by project type



National total
2018$ (B)

2020s	**183**
2030s	**715**
2040s	1,630
Total	**2,527**

E+ RE+ (Base siting)
Cumulative capital invested in transmission (2020-2050), by decade

Note: These capital estimates are for transmission expansions. The values labeled solar, onshore wind, and offshore wind are spur lines from solar or wind projects to nearest substations. Sustaining capital invested for end-of-life line replacements is not included in the totals here, but is included in transmission capital investment estimates in the capital mobilization section of this report.

Cumulative land use impacts of wind and solar deployment



Summary of this section

- Cumulative land use impacts of wind and solar deployment in the E+ case (2021-2050):
  - Total area spanned by onshore wind and solar farms is ~590,000 sq-km, an area roughly equal to the size of IL, IN, OH, KY, TN, MA, CT and RI put together. Offshore wind farms span 33,000 sq-km.
  - Wind projects drive total farm area, which is concentrated in the Great Plains and Midwest and primarily on crop, pasture, and forested lands.
  - Wind farms have large spatial extent and significant visual impact, but directly impact only 1% of total site area and can co-exist with farming and grazing.
  - Conversely, directly impacted land area is dominated by solar and greatest in the Northeast and Southeast; forested lands make up the largest directly impacted land cover type.
  - Solar farms are more compact but also more intensive, directly impacting ~90% of their area.
  - Wind and solar present different land use impacts, with particular advantages and challenges.
- Cumulative total wind and solar farm area in E+ RE+ by 2050 is ~1 million km², or roughly an area the size of AK, IA, KS, MO, NE, OK, and WV combined (with an additional 64,000 km² of offshore wind); directly impacted lands total 70,000 km², an area larger than WV.
- Only 3% of Constrained solar candidate project areas are selected in E+ and 5% in E+ RE+, indicating potential to substantially reconfigure solar siting to minimize conflict.
- Wind farms use 57% and >100% of Constrained candidate project areas in E+ and E+ RE+, respectively, and face shortfalls in some regions, indicating greater potential for wind to be constrained by siting challenges.

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2030 solar and wind siting summary for E+ and E+ RE+ cases



	2030 E+			2030 E+ RE+		
	Solar	**Onshore Wind**	**Offshore wind**	**Solar**	**Onshore Wind**	**Offshore wind**
Capacity installed (GW) [a]	324	414	111	405	490	5
Solar and wind farm area (km²)	7,800	156,700	1,000	10,400	185,900	1,000
Directly impacted (km²) [b]	7,000	1,600	10	9,500	1,900	10
Percent of total candidate project areas used						
Base site availability	0%	5%	0%	1%	17%	8%
Constrained site availability	1%	16%	4%	2%	46%	62%

[a] With Base site availability. **[b]** Equipment, roads, infrastructure.

2050 solar and wind siting summary for E+ and E+ RE+ cases



	2050 E+			2050 E+ RE+		
	Solar	**Onshore Wind**	**Offshore wind**	**Solar**	**Onshore Wind**	**Offshore wind**
Capacity installed (GW) [a]	1,500	1,500	200	2,800	2,700	400
Solar and wind farm area (km²)	38,000	551,000	33,000	66,000	1,009,000	64,000
Directly impacted (km²) [b]	34,000	5,000	300	60,100	10,000	600
Percent of total candidate project areas used [with regional shortfalls as noted]						
Base site availability	1%	18%	14%	3%	34%	27% [c]
Constrained site availability	3%	57% [d]	137% [e]	5%	104% [d]	248% [f]

[a] With Base site availability. **[b]** Equipment, roads, infrastructure. **[c – f]** Insufficient available sites in some regions result in shortfalls in regional supply of wind energy in: insufficient sites in [c] Mid-Atlantic/Great Lakes, [d] Mid-Atlantic/Great Lakes, Louisiana/Ozarks, Desert SW, [e] Mid-Atlantic/Great Lakes, New York, New England, [f] all regions except California.

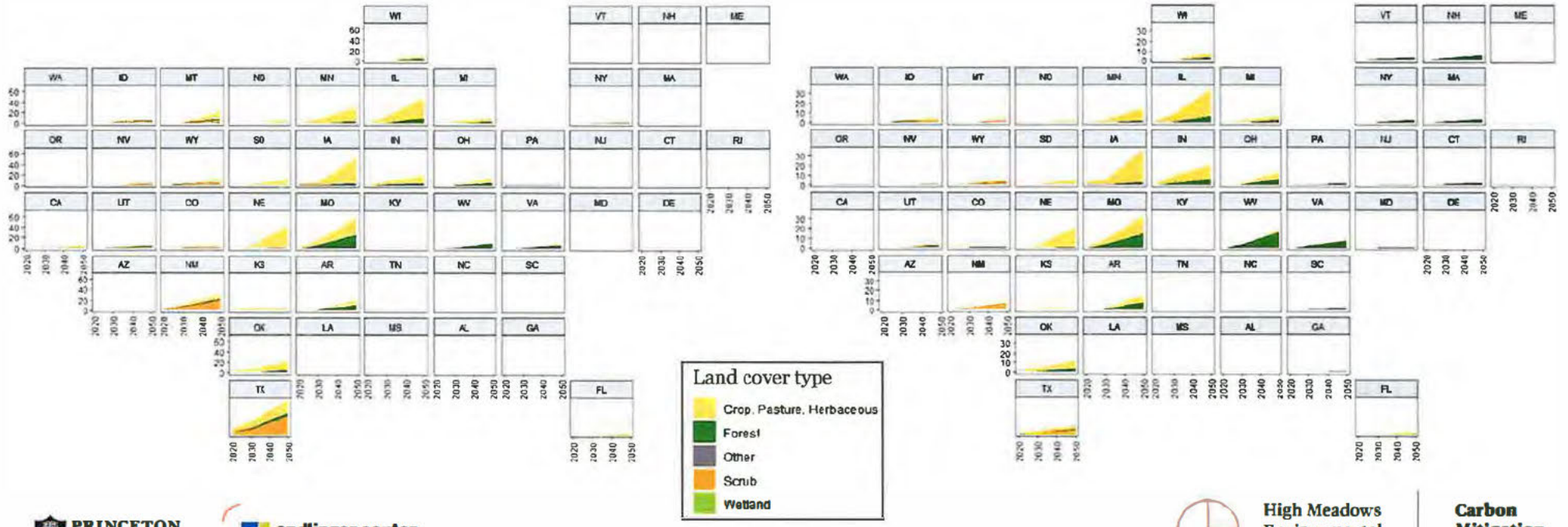
Total wind and solar farm areas are *de minimis* in most states, with the exception of the Great Plains and Midwest.

Total wind and solar farm area (1,000 km²)

The area impacted by total wind and solar farm boundaries by mid-century ranges from ~10 km² in Delaware to ~68,000 km² in Texas.

Total wind and solar farm area as percent of state land area (%)

The share of state land area encompassed by wind and solar farms by mid-century ranges from <1% in Kentucky to ~37% in Iowa.



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Carbon Mitigation Initiative

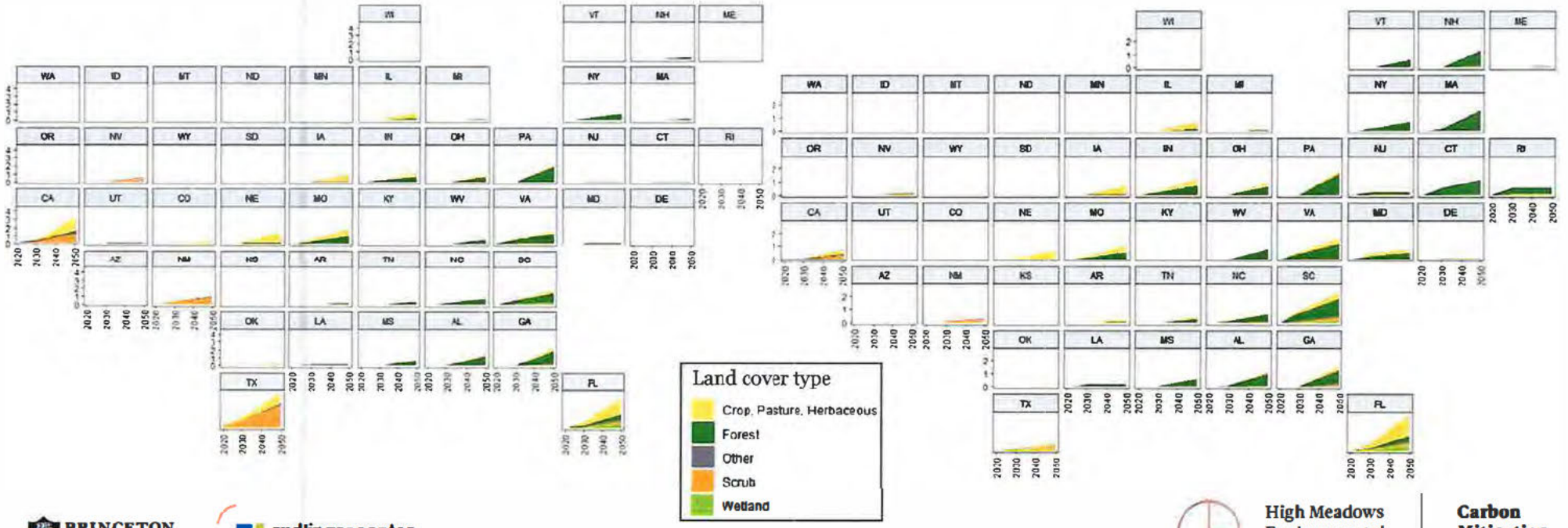
Direct land impacts are greatest in states with high amounts of solar deployed, including in the Northeast and Southeast.

Land area directly impacted by solar and wind development (1,000 km²)

The directly impacted land area by mid-century ranges from ~4 km² in Kentucky to ~4,400 km² in Texas.

Percentage of state land area directly impacted by solar and wind development (%)

The share of state land area directly impacted by mid-century ranges from <<1% in Kentucky to ~3% in Florida.



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Carbon Mitigation Initiative

Clean firm resources and thermal plant retirements



Summary of this section

- Installed capacity of "firm" generation sources — technologies that can produce power on demand, any time of year, for as long as required — remains similar to current levels in all scenarios, with ~500-1,000 GW (vs. 875 GW today).
- Coal fired capacity is completely retired by 2030 across all NZA scenarios with decline rates similar across all regions at higher than the historical peak of 21 GW/y in 2015. No new coal fired capacity is added in any scenario.
- About 50% of existing nuclear capacity retires by 2050 in all NZA scenarios; the E+RE+ scenario phases out nuclear by 2050 with 15 GW retired by 2030.
- New advanced nuclear generation capacity is added in all scenarios except in E+RE+; expansion is modest in E+, E- and E+RE- with ~10-20 GW deployed in the 2030s and 2040s. The E+RE- scenario expands new nuclear capacity rapidly from 2025-2050, deploying ~260 GW by 2050, requiring historically unprecedented build rates in the 2040s.
- Natural gas retirements vary across NZA scenarios, with the E+RE+ scenario seeing the most (224 GW) and the E+RE+ scenario seeing the least capacity retired (175 GW). By 2050, cumulative retirements are consistent across most NZA scenarios (450 GW) except for the E+RE- scenario (506 GW).
- New natural gas fired capacity is added in all scenarios except E+RE+. The most new capacity is added in E+RE- which sees ~580 GW of new gas capacity (around 230 GW with CO_2 capture) by 2050.
- To meet firm capacity needs in the 100% renewable E+RE+ scenario, ~590 GW of new combustion turbine and combined cycle power plants are deployed and by 2050 are fired entirely with zero-carbon synthetic gas.
- Siting studies indicated that most of the new thermal generation capacity can be sited at existing coal, natural gas and nuclear plant sites with few new sites to be developed, but many existing sites would fail on at least one current safety or environmental criteria applied to new greenfield projects.

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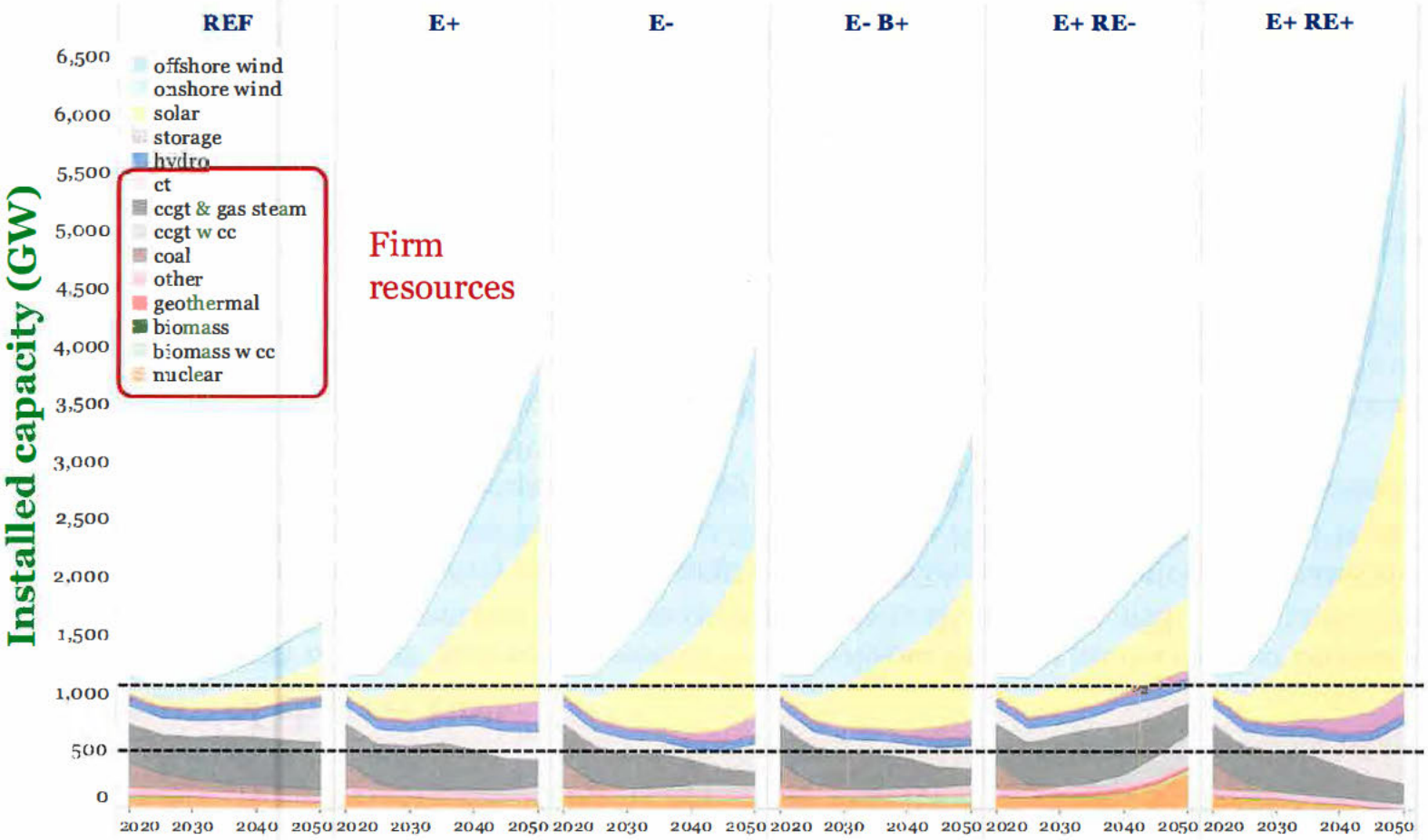
Firm capacity stays comparable to today; high H_2 fuel blends for gas turbines have important role; nuclear & gas w/CCS key in RE-



Note:

To reduce the carbon intensity of CCGT and CT generation, H_2 is blended as an increasing fraction of fuel to these units, up to an exogenously specified cap of 60% (HHV basis).

In sensitivities with 100% H_2 firing allowed, the model prefers 100% blend which modestly reduces total energy system costs.

Firm capacity (across all years)

~500-1000 GW

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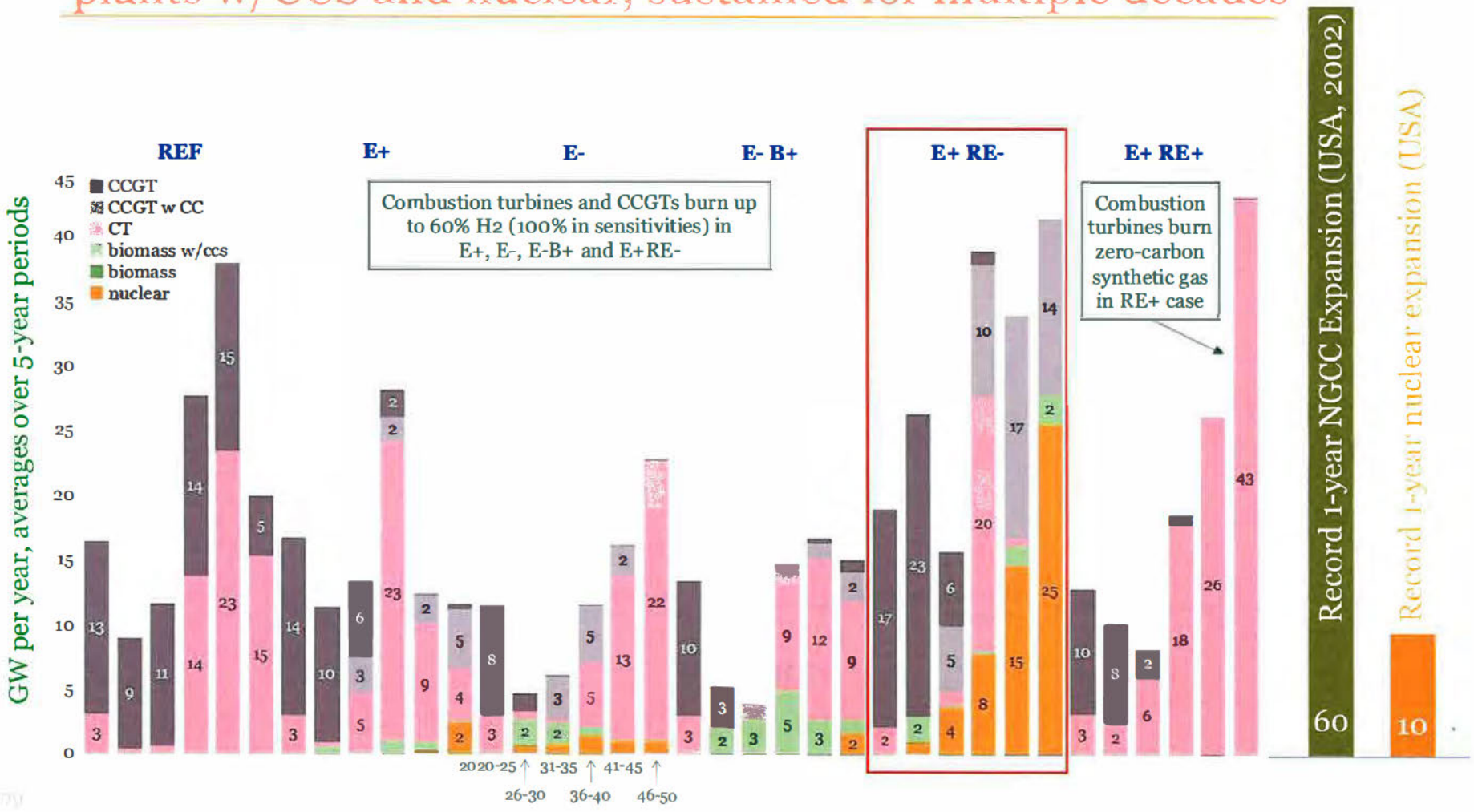
E+ RE- requires historically-unprecedented growth rates for gas plants w/CCS and nuclear, sustained for multiple decades



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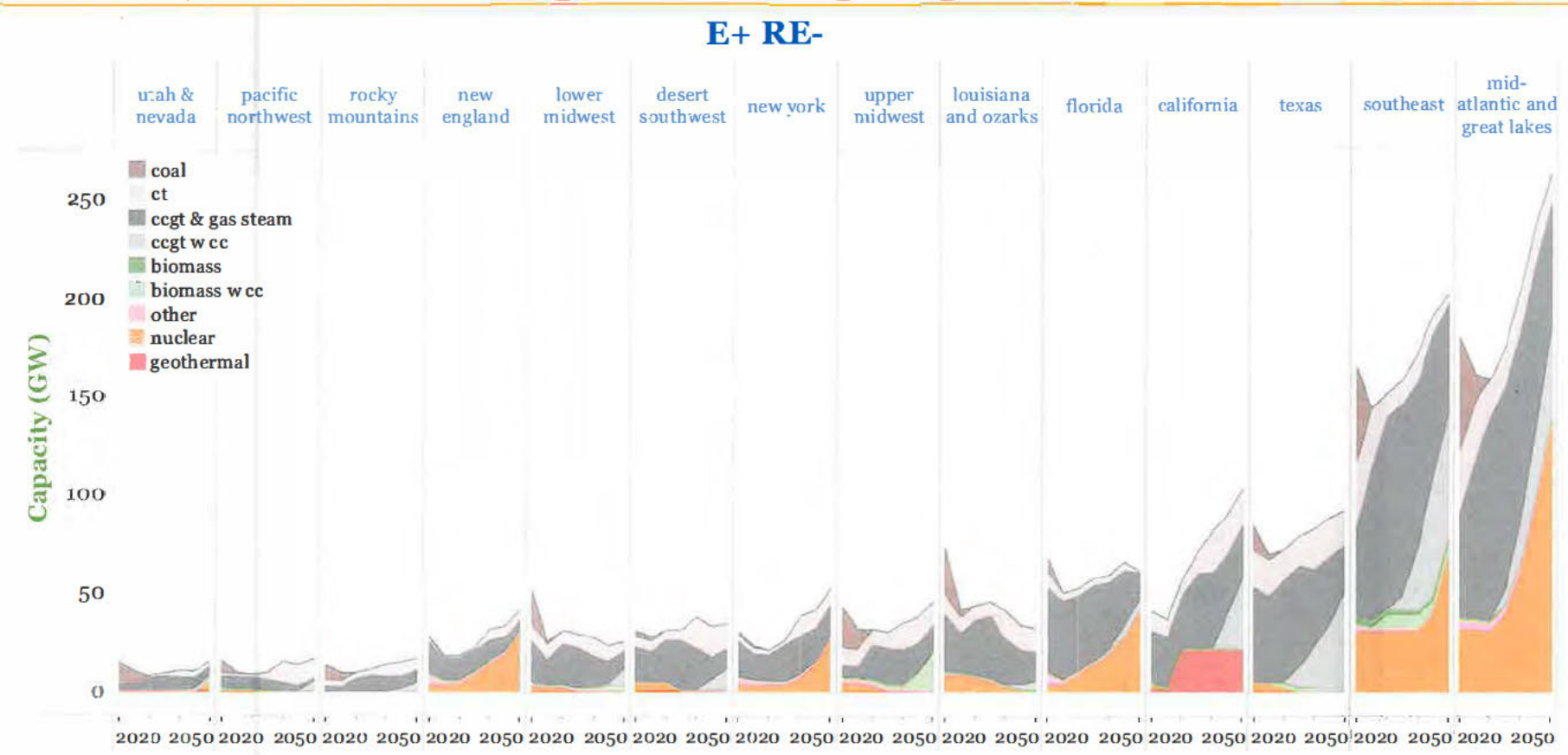
New England, New York, California, Florida, Southeast and Mid-Atlantic/ Great Lakes regions see largest growth





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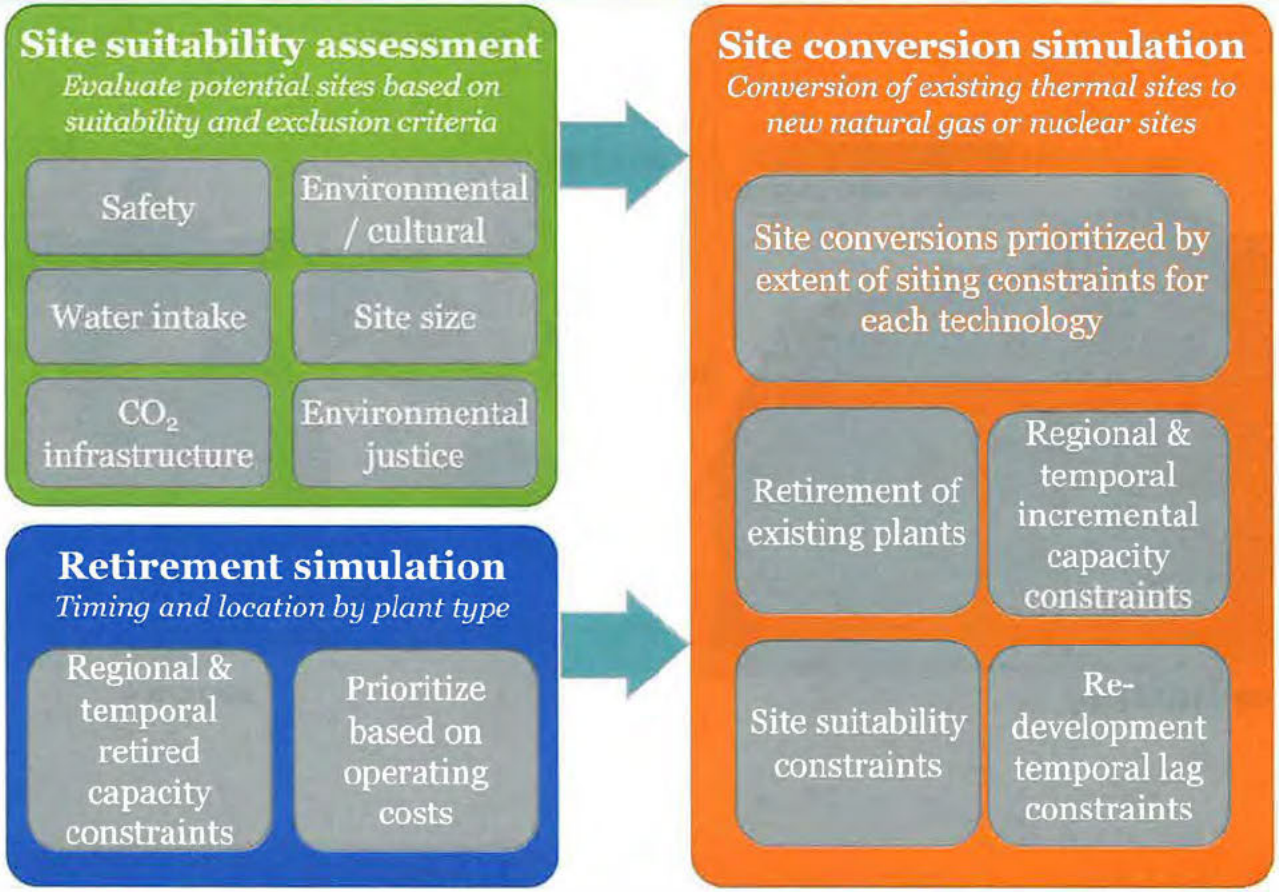
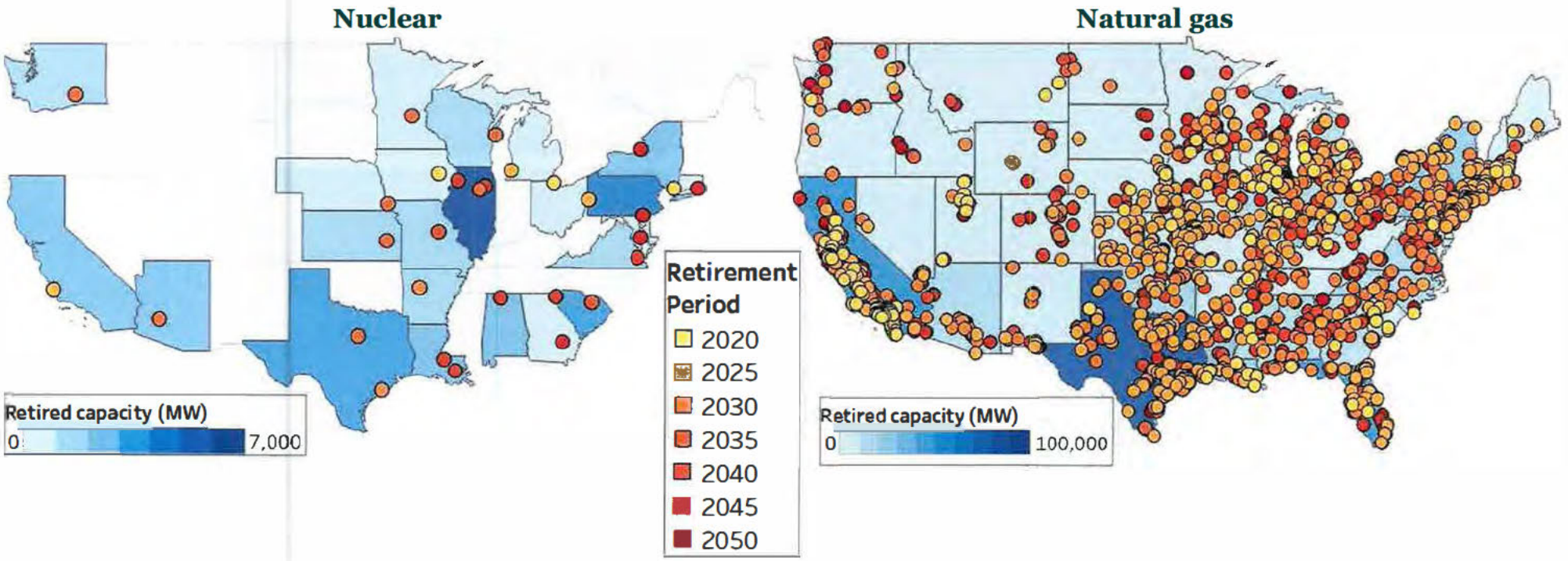
Modeling conversion and retirement of coal, gas, and nuclear plants and sites considers operating costs and site suitability criteria.



Due to age, 45% of nuclear and 80% of gas capacity assumed to retire by 2050; repowering or low-carbon site conversions possible.



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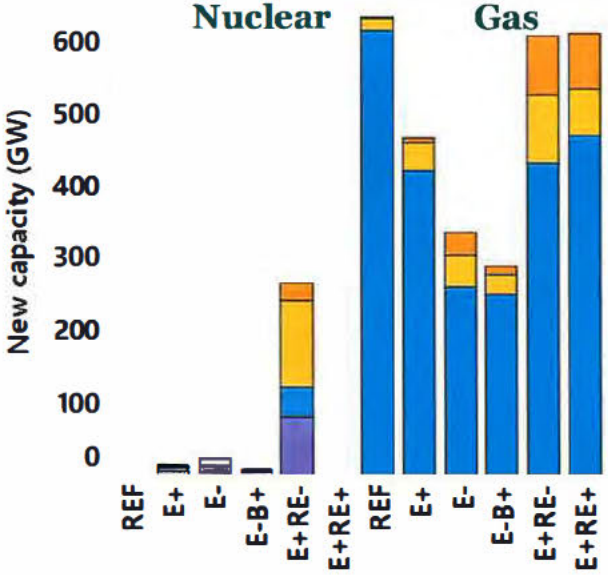
Most new gas and nuclear capacity can be accommodated at existing thermal plant sites, if no new siting restrictions are applied.

New capacity by site type cumulative 2020 - 2050



- New sites
- Existing coal sites
- Existing natural gas sites
- Existing nuclear sites

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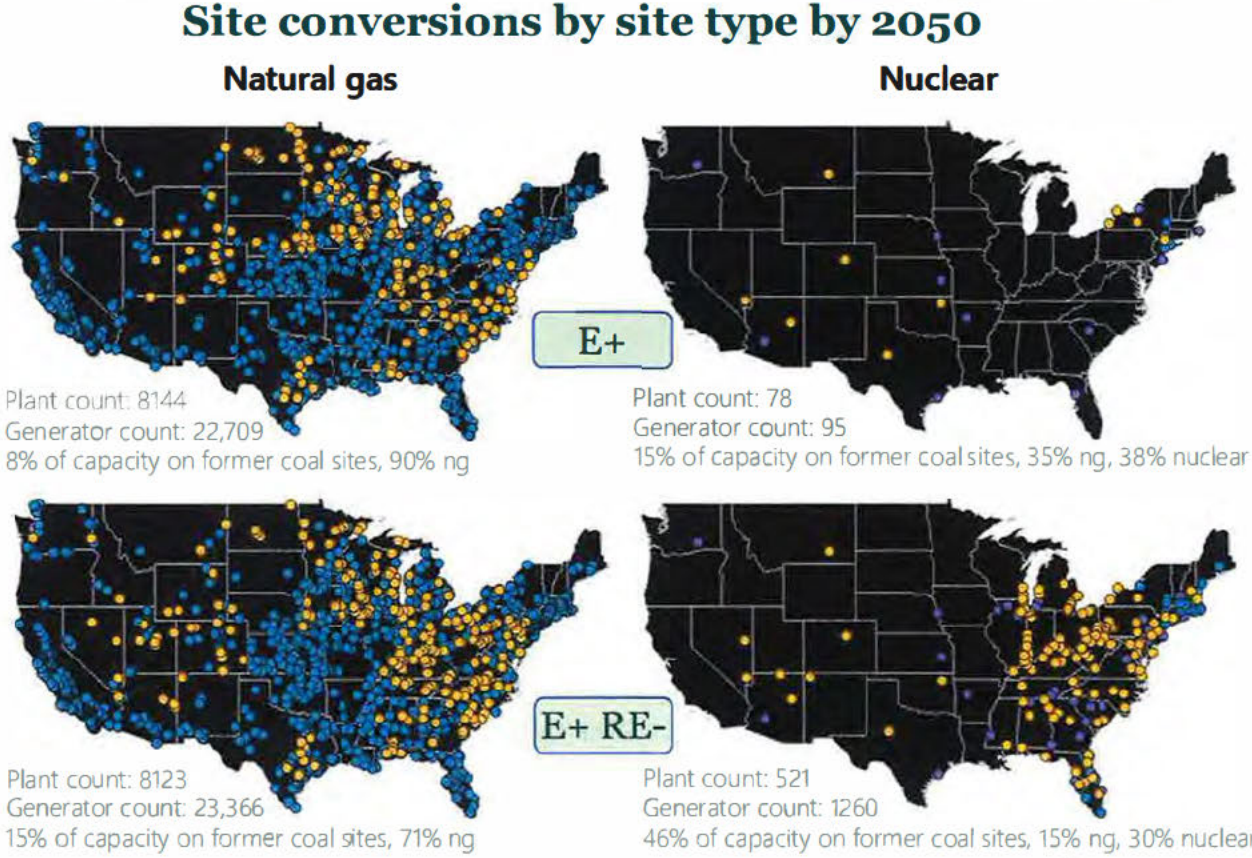
Site conversions by site type by 2050



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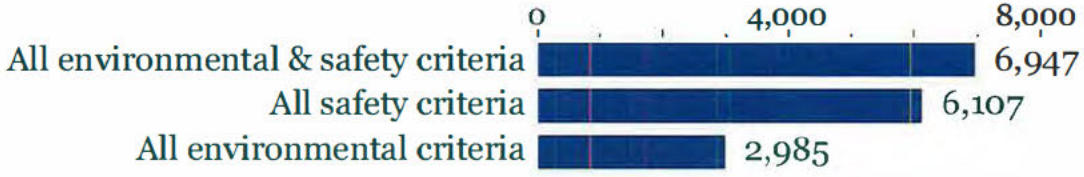
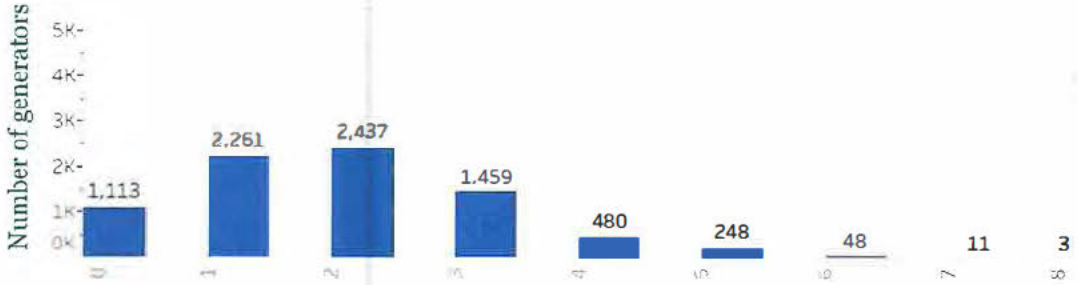
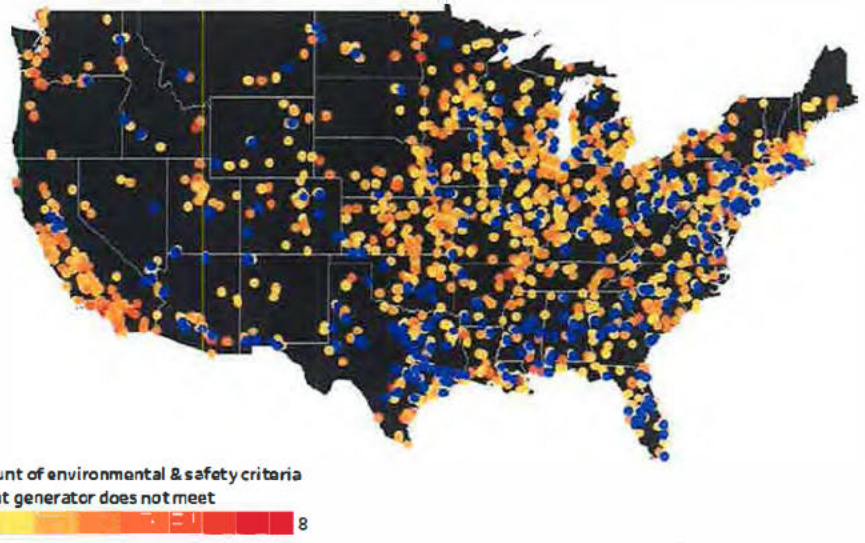
But most existing locations would fail to meet one or more safety or environmental suitability criteria for 'greenfield' projects today.

Number of current generator locations that would fail to meet site suitability criteria







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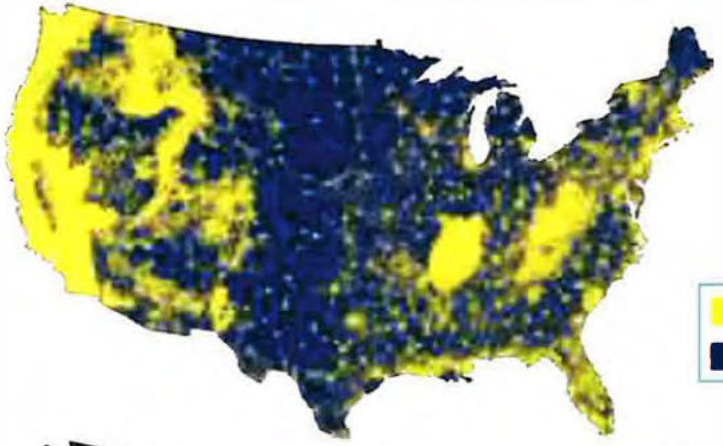
Examples of safety, environmental and cultural, water, and carbon-storage proximity siting criteria.

Safety

Exclusions include urban areas, flood zones, earthquake regions, etc.



Environmental and cultural

35 exclusion types (wetlands, national parks, landscape intactness, etc.)



Unsuitable area
Suitable area

Cooling water sources



CO_2 sinks

Natural gas combined cycles with CO_2 capture must be sited near storage basins or CO_2 pipeline infrastructure.



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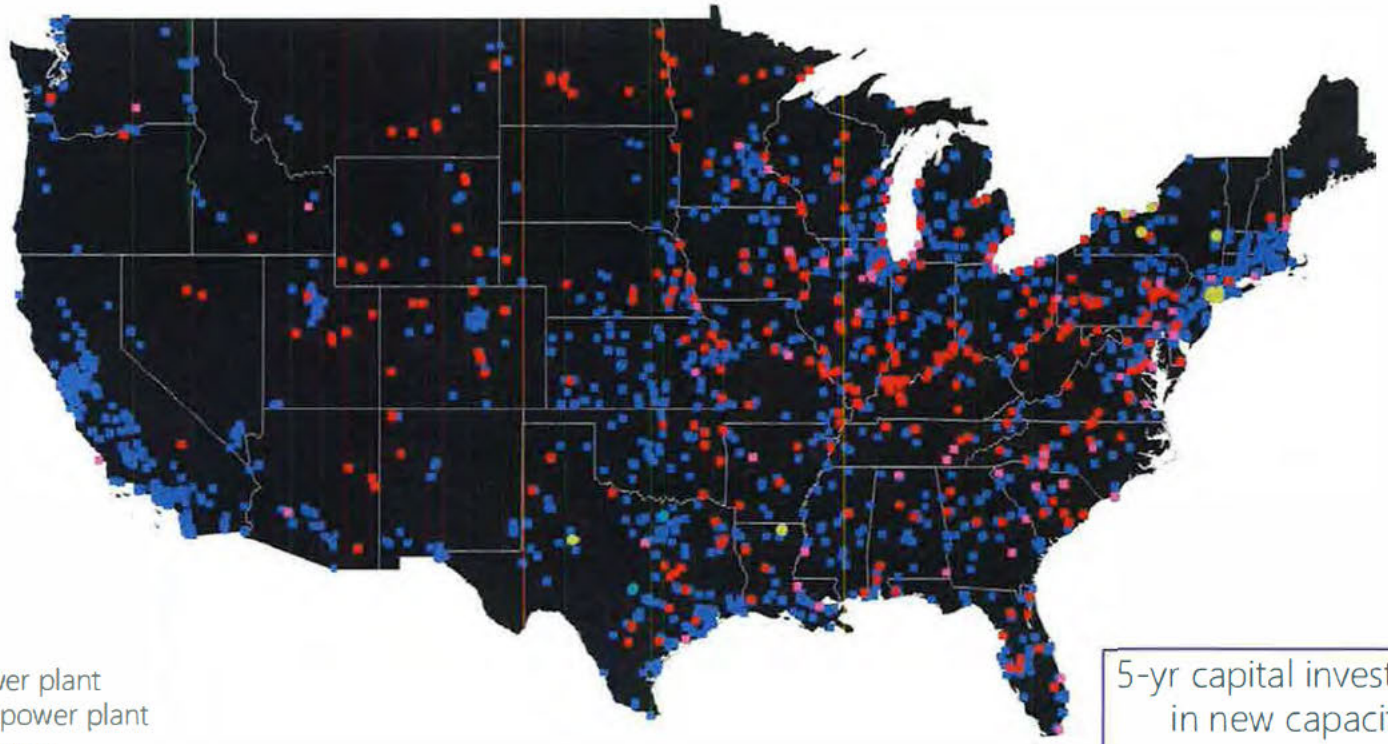
Evolution of coal, natural gas, and nuclear generators in E+ with no new siting-criteria filters applied, 2020

2020



- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

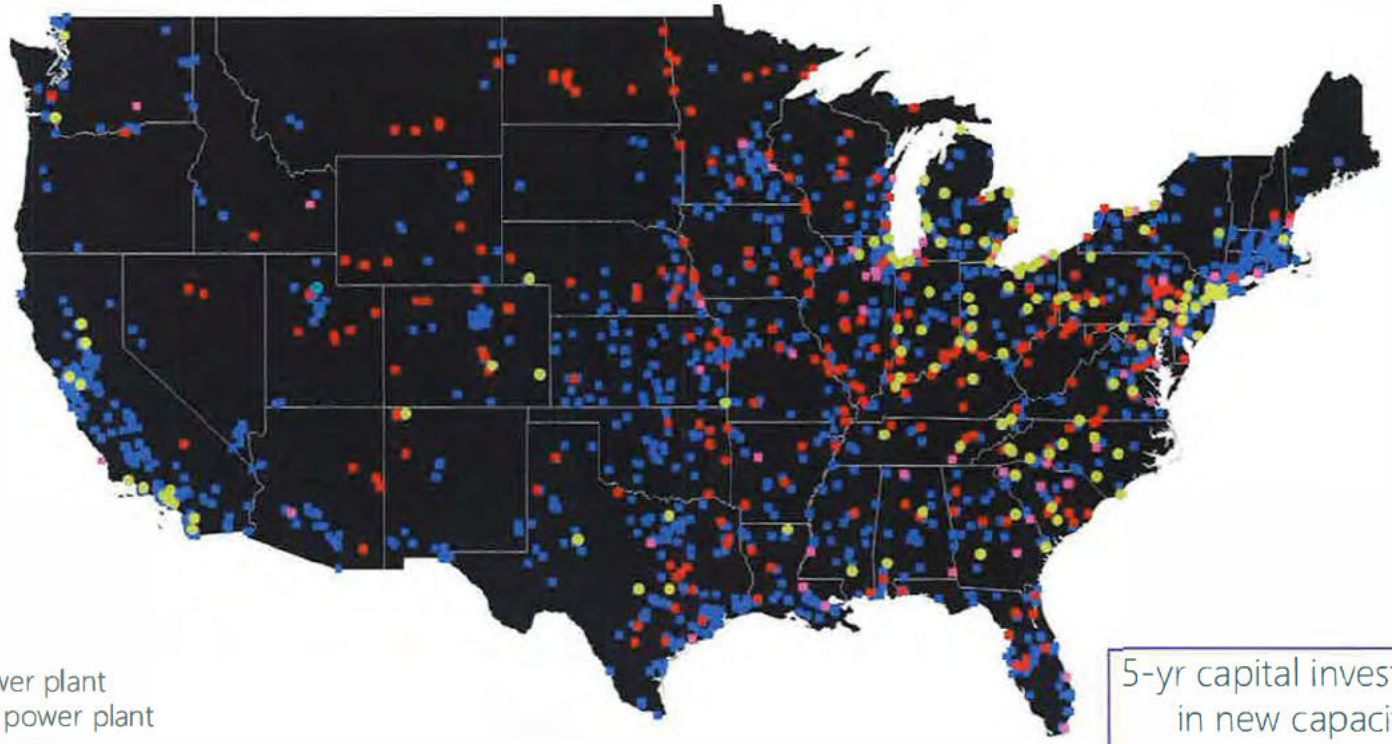
5-yr capital investment in new capacity:

$11B

Evolution of coal, natural gas, and nuclear generators in E+ with no new siting-criteria filters applied, 2025



2025



- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

5-yr capital investment in new capacity:

$70B

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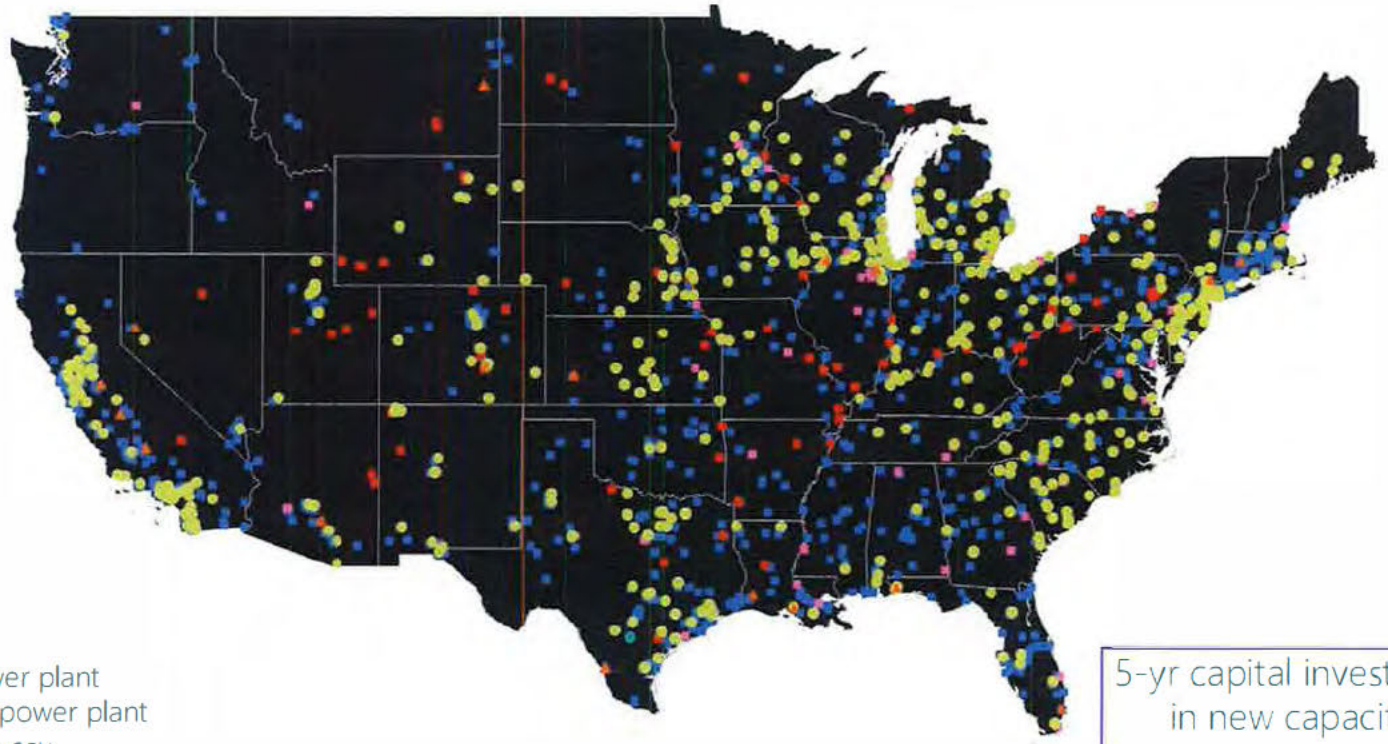
Carbon Mitigation Initiative

Evolution of coal, natural gas, and nuclear generators in E+ with no new siting-criteria filters applied, 2030

2030



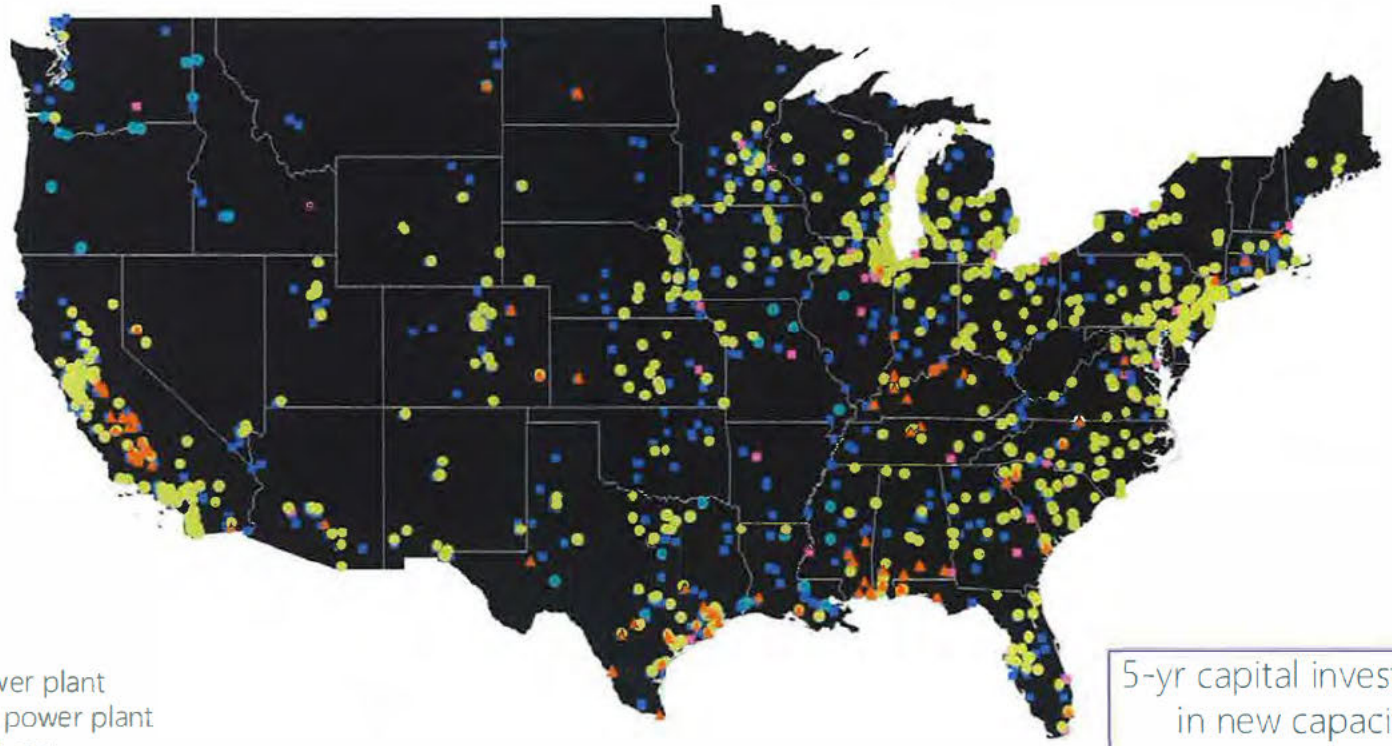
- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

5-yr capital investment in new capacity:

$46B

Evolution of coal, natural gas, and nuclear generators in E+ with no new siting-criteria filters applied, 2035

2035



- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

5-yr capital investment in new capacity:

$66B

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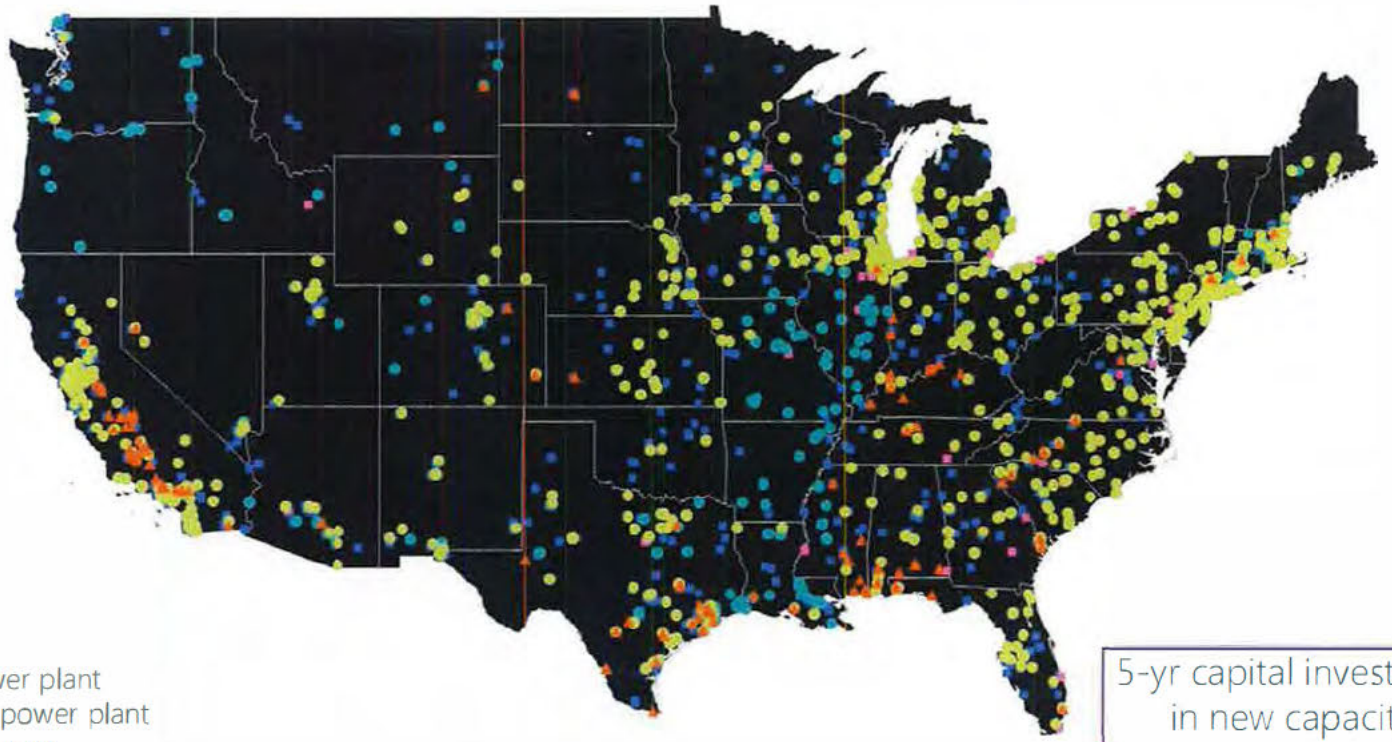
Carbon Mitigation Initiative

Evolution of coal, natural gas, and nuclear generators in E+ with no new siting-criteria filters applied, 2040

2040



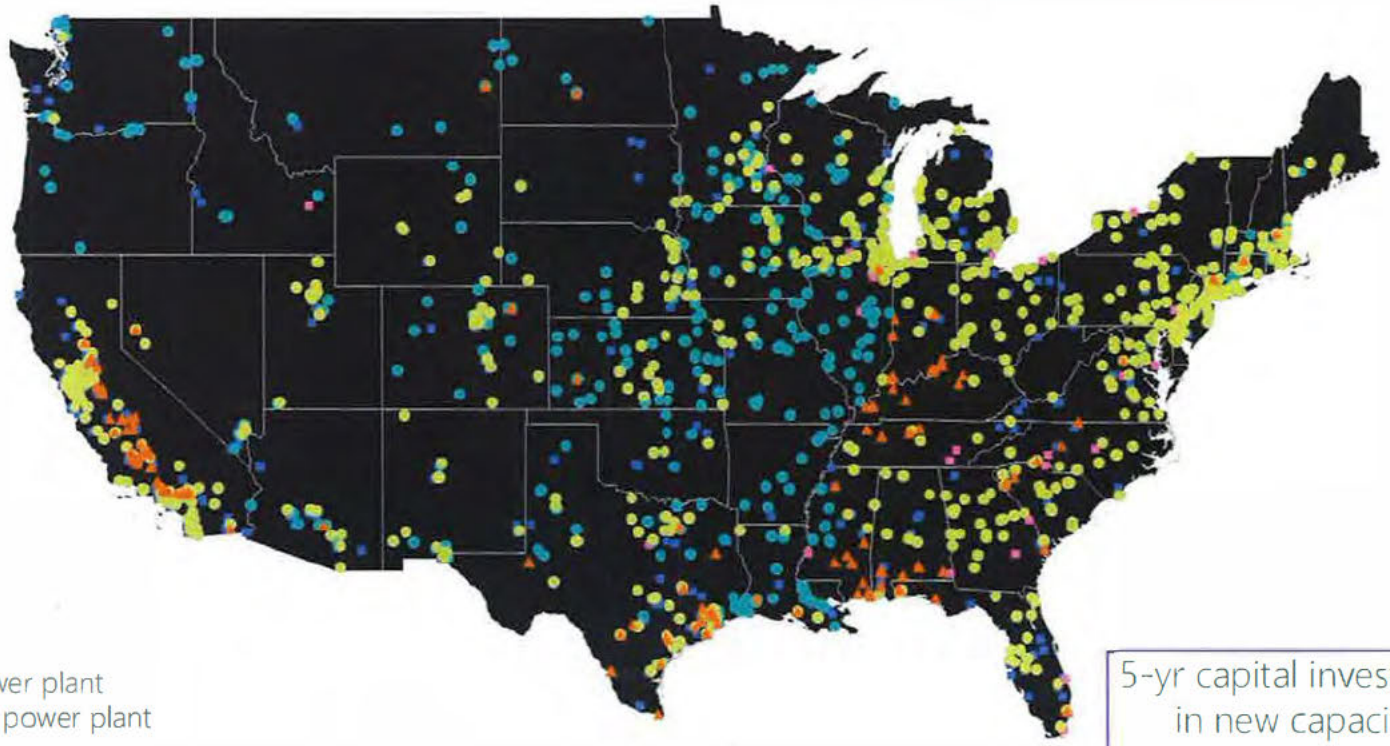
- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

5-yr capital investment in new capacity:

$90B

Evolution of coal, natural gas, and nuclear generators in E+ with no new siting-criteria filters applied, 2045

2045



- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

5-yr capital investment in new capacity:

$54B

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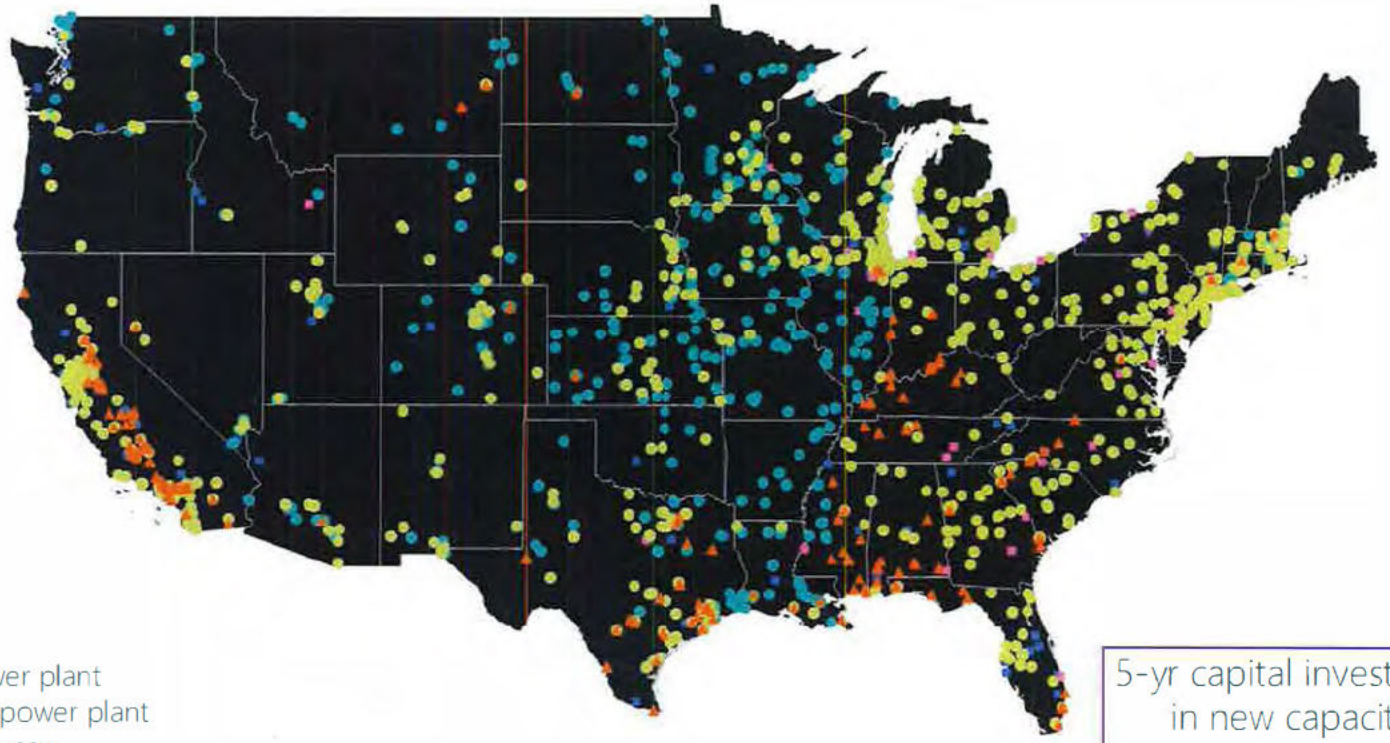
Carbon Mitigation Initiative

Evolution of coal, natural gas, and nuclear generators in E+ with no new siting-criteria filters applied, 2050

2050



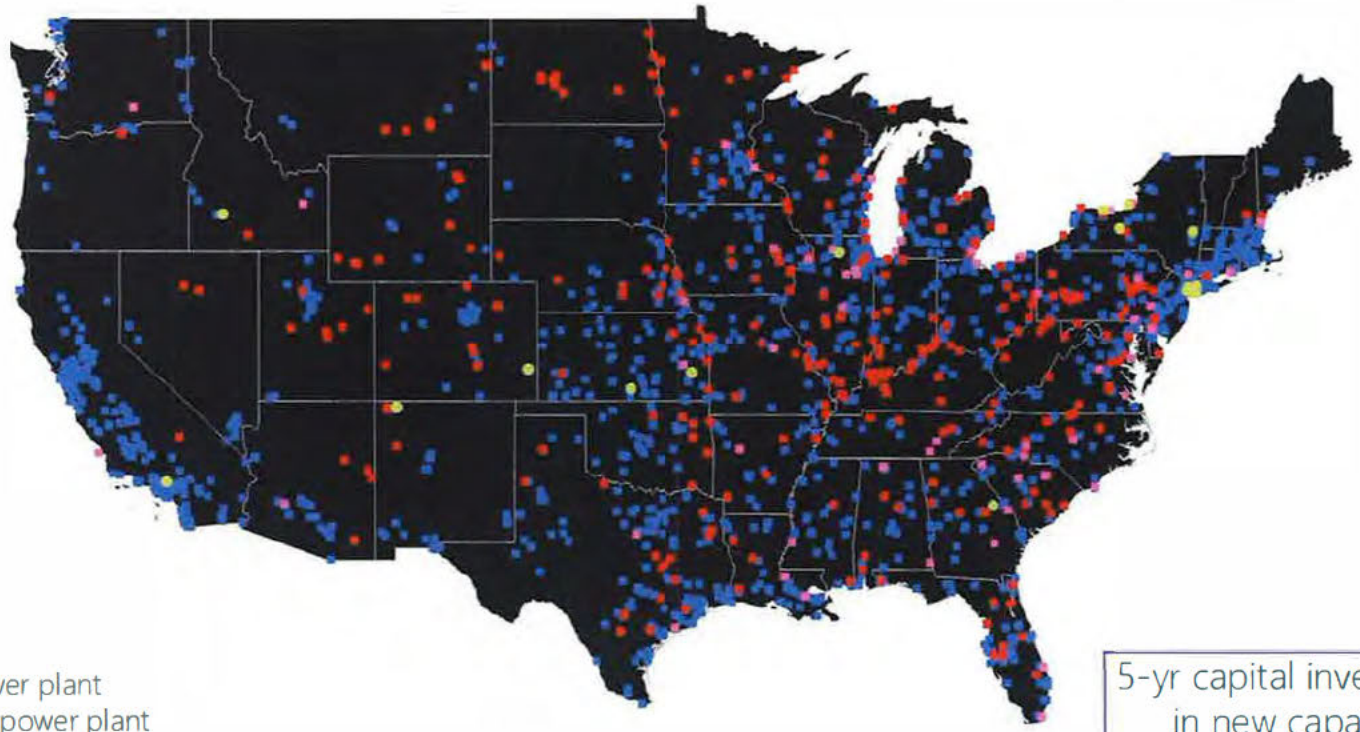
- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

5-yr capital investment in new capacity:

$123B

Evolution of coal, natural gas, and nuclear generators in E+ RE- with no new siting-criteria filters applied, 2020

2020



- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

5-yr capital investment in new capacity:

$12B

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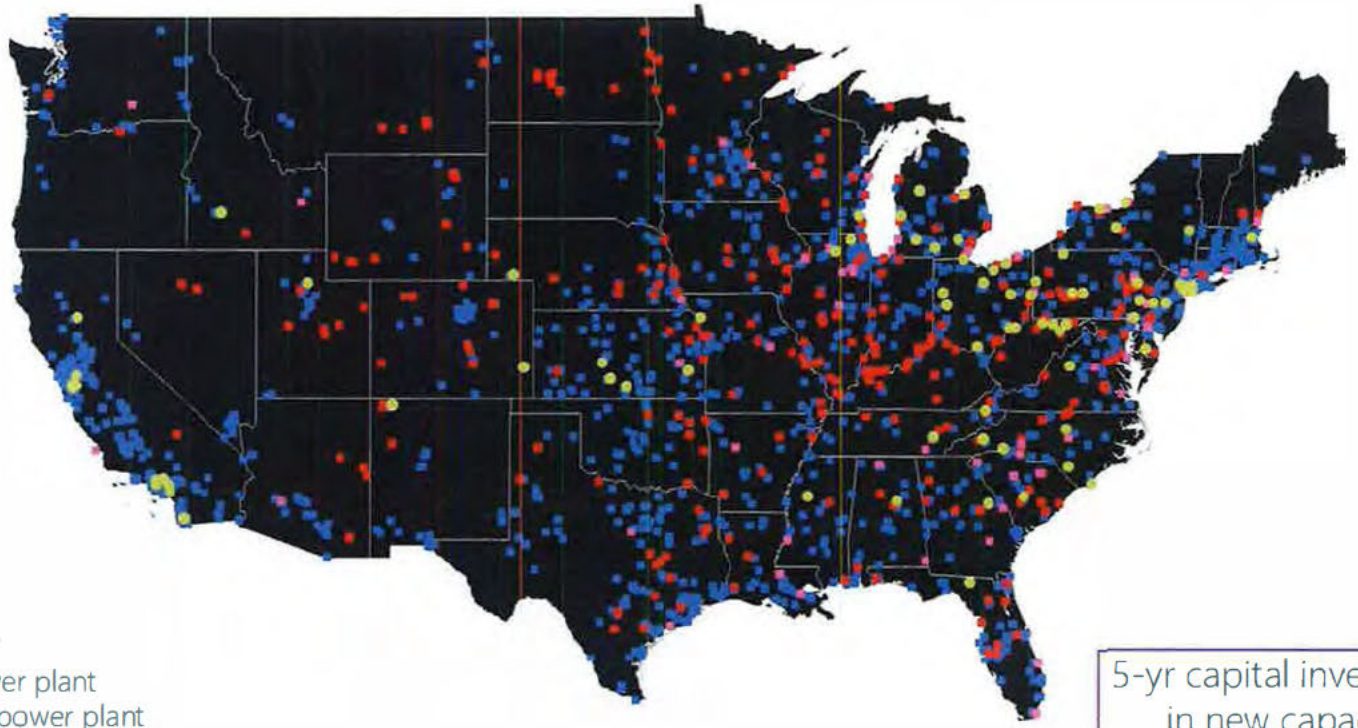
Carbon Mitigation Initiative

Evolution of coal, natural gas, and nuclear generators in E+ RE- with no new siting-criteria filters applied, 2025

2025



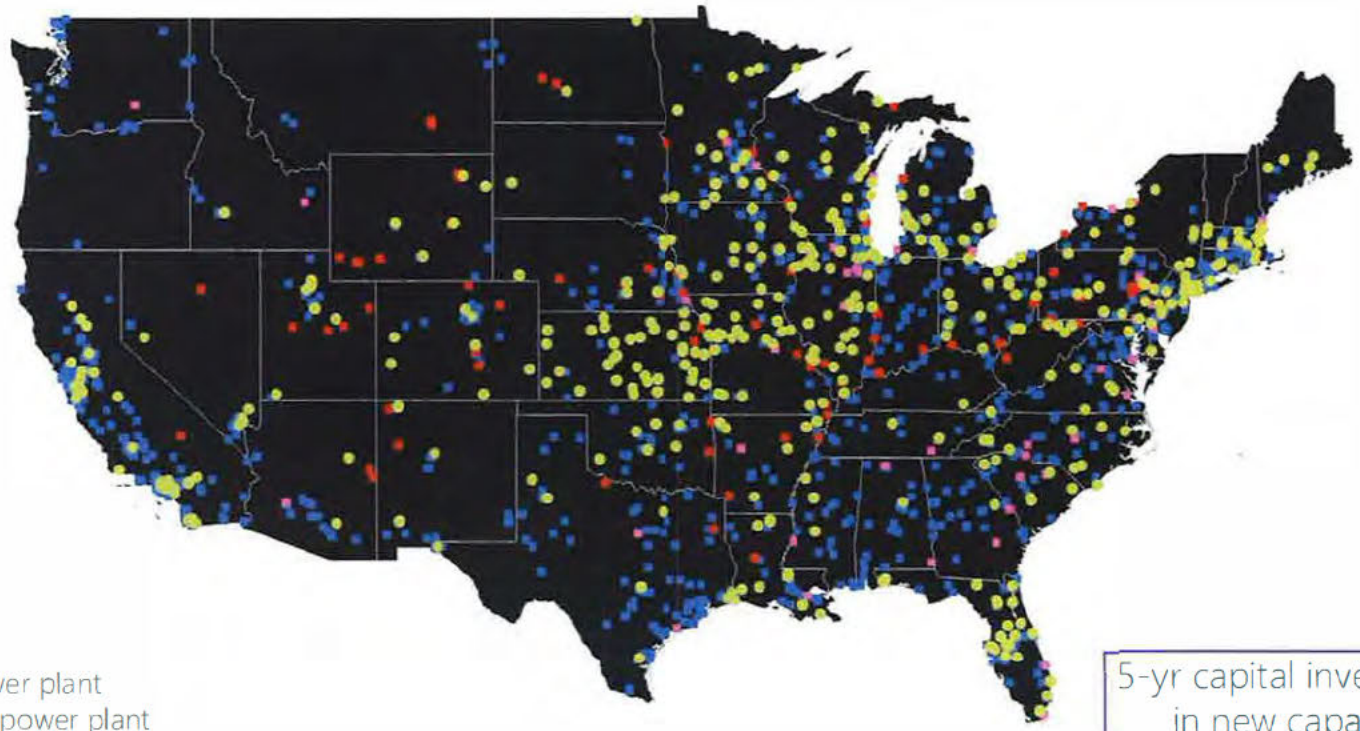
- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

5-yr capital investment in new capacity:

$83B

Evolution of coal, natural gas, and nuclear generators in E+ RE- with no new siting-criteria filters applied, 2030

2030



- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

5-yr capital investment in new capacity:

$129B

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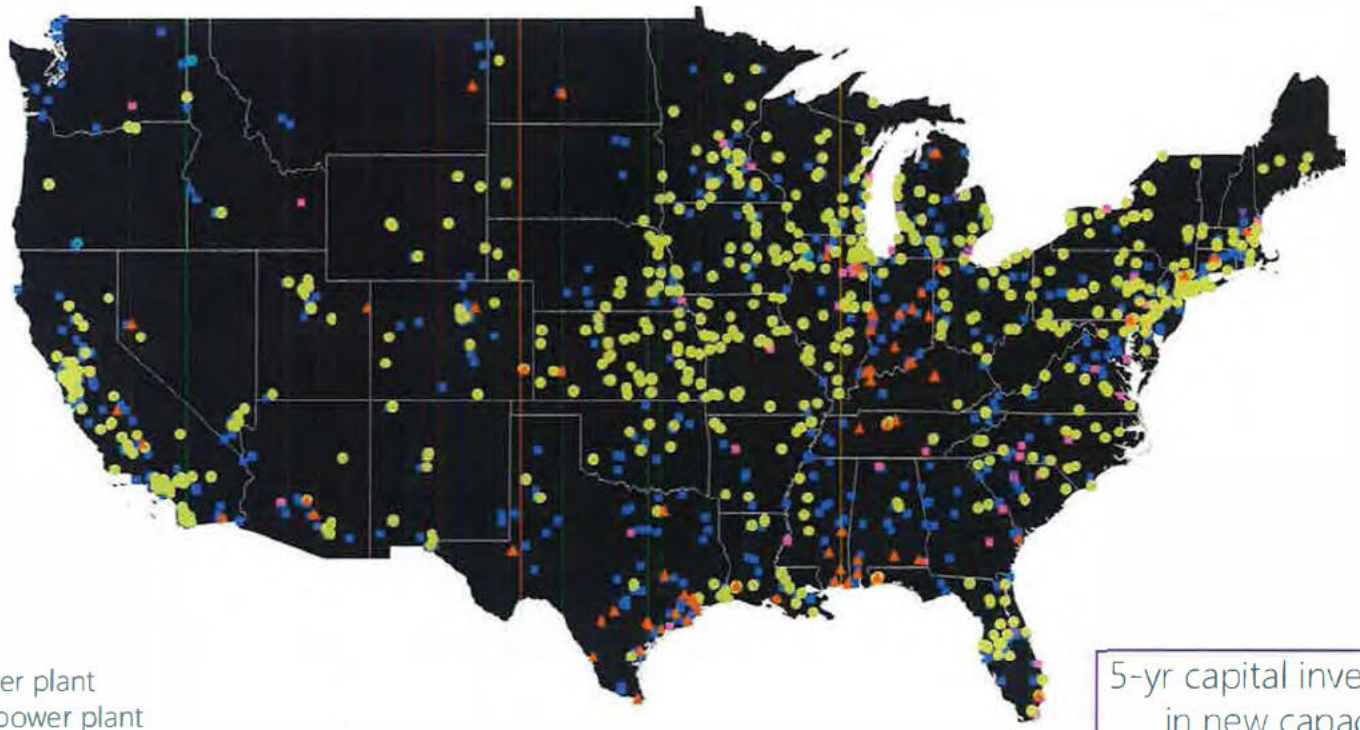
Evolution of coal, natural gas, and nuclear generators in E+ RE- with no new siting-criteria filters applied, 2035

2035



- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

5-yr capital investment in new capacity:

$184B

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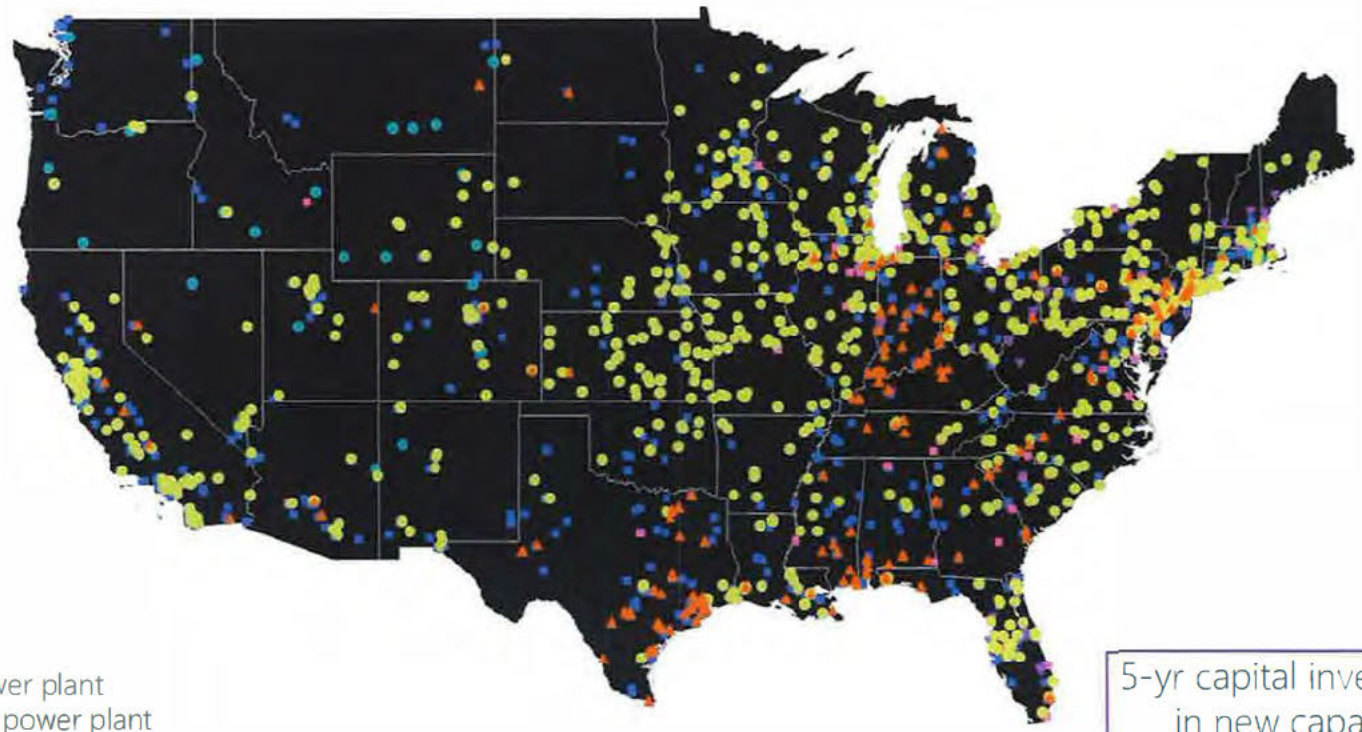
Evolution of coal, natural gas, and nuclear generators in E+ RE- with no new siting-criteria filters applied, 2040

2040



- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

5-yr capital investment in new capacity:

$382B

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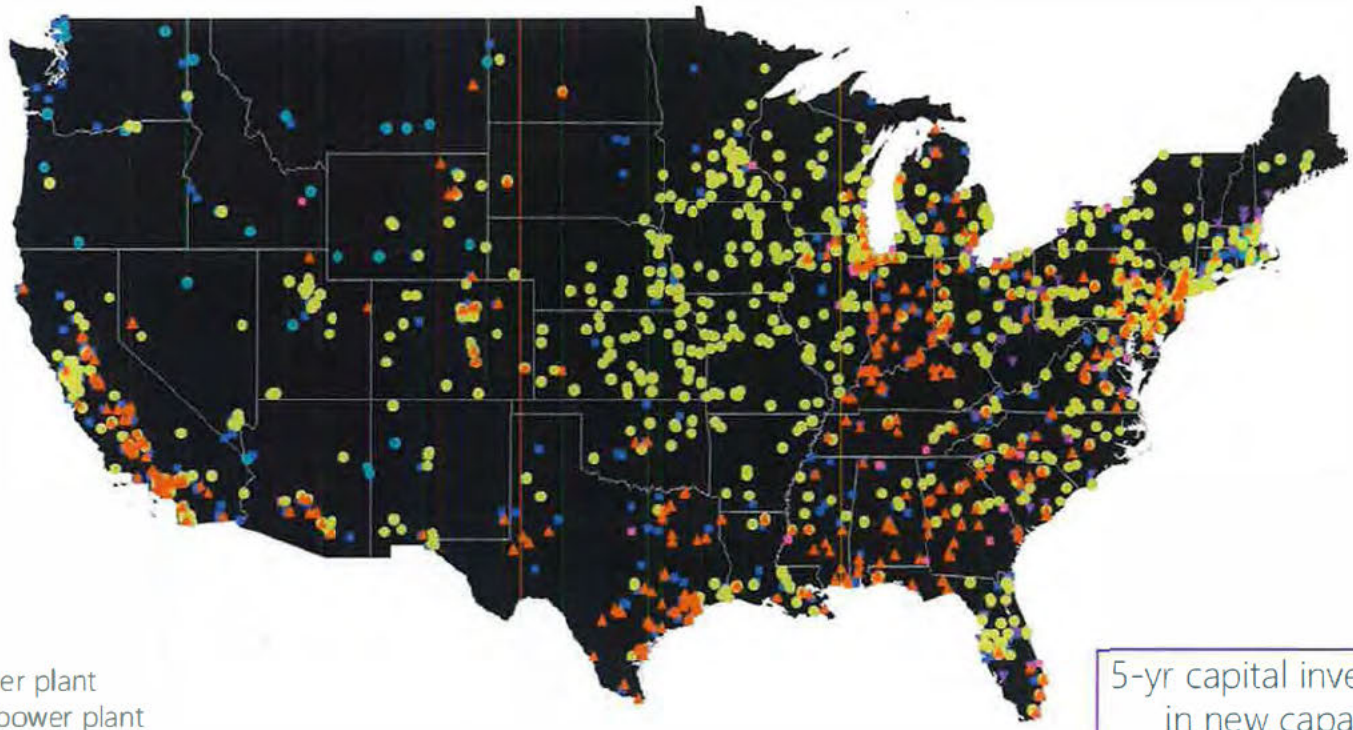
Evolution of coal, natural gas, and nuclear generators in E+ RE- with no new siting-criteria filters applied, 2045

2045



- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combined cycle power plant
- New gas combustion turbine power plant
- New gas combined cycle with ccu
- New advanced nuclear plant

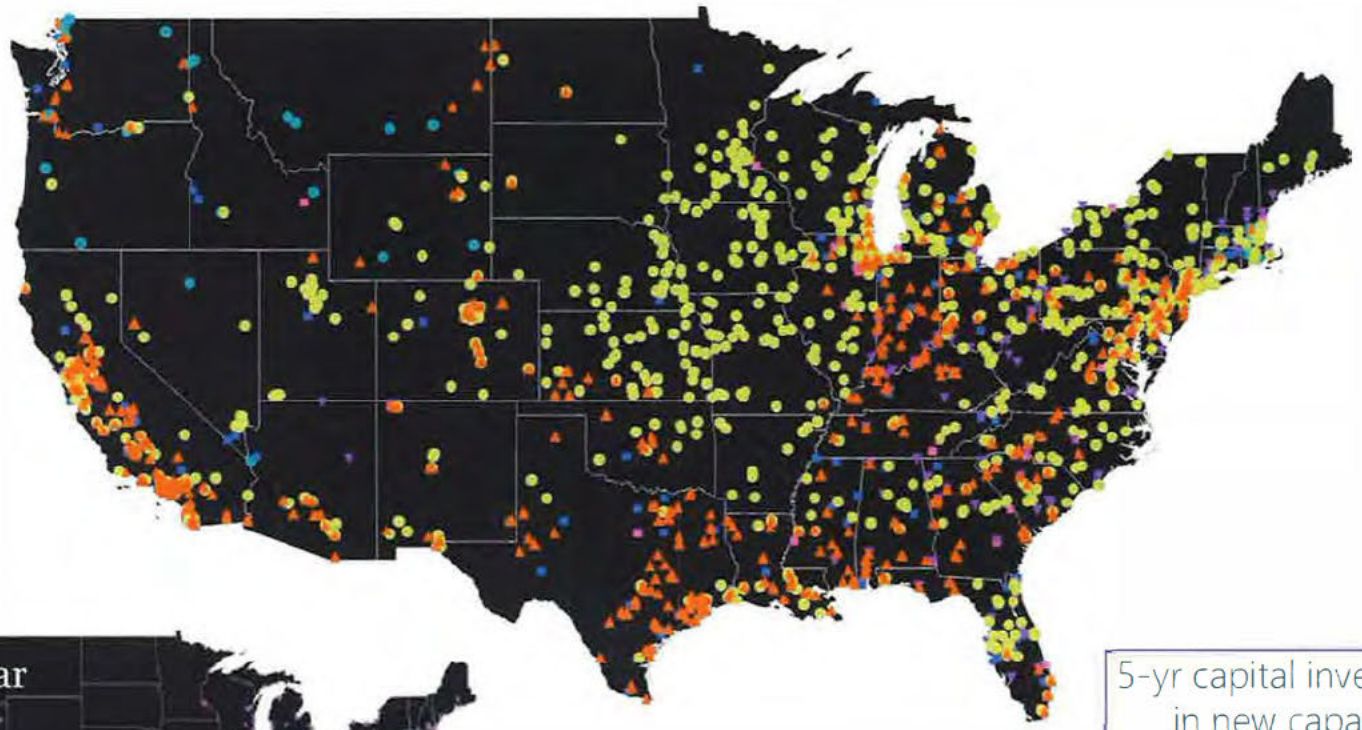
5-yr capital investment in new capacity:

$583B

Evolution of coal, natural gas, and nuclear generators in E+ RE- with no new siting-criteria filters applied, 2050



2050



- Existing coal
- Existing natural gas
- Existing nuclear
- New gas combine
- New gas combust
- New gas combine
- New advanced nu



5-yr capital investment in new capacity:

$833B

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Carbon Mitigation Initiative

Pillar 3: Bioenergy and other zero-carbon fuels and feedstocks



Summary of this section

- The modeling includes ways to realize carbon-neutral or carbon-negative fuels in net-zero scenarios starting from fossil fuels, from biomass, and/or from clean electricity. Hydrogen is a key carbon-free intermediate or final fuel.
- Biomass plays an especially important role because *i*) it removes CO_2 from the atmosphere as it grows and so combustion of hydrocarbon fuels made with biomass carbon results in no net CO_2 emissions to the atmosphere, *ii*) it can be converted into H_2 while capturing and permanently sequestering its carbon, resulting in a net negative-emissions fuel, and *iii*) it can similarly be used to make negative-emissions electricity.
- The biomass supply in 4 of the 5 net-zero scenarios consists of agricultural and forest residues, plus transitioning land area growing corn for ethanol to growing perennial grasses or equivalent for energy.* This supply scenario thus includes no conversion of land currently used for food or feed production.
- The high biomass supply case (E- B+ scenario) assumes all biomass identified in the US Department of Energy's "Billion Ton Study" is available for energy; this involves some food agricultural land being converted to energy crops.
- Starting in the 2030s, H_2 from biomass with capture of CO_2 that is permanently sequestered is a highly cost-competitive technology option because of the high value of the associated negative emissions; negative-emissions bio-electricity is less valued because of abundant low cost of solar and wind electricity.

* The average rain-fed harvestable yield (t/ha/y, dry basis) of perennial energy grasses on former corn-growing land assumed in the modeling here is about ¾ of today's U.S. average whole-plant yield for corn. Conceptually, therefore, the biomass assumed to be supplied from converted corn-growing lands could equivalently be whole-corn-plant biomass with ¼ of the material left on the field for soil maintenance purposes.

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Key zero-carbon fuels and feedstocks

1. Fossil-derived fuels with negative emissions offsets



2. Hydrogen made from biomass, NG w/CCS, or electrolysis and used directly or as hythane (blend of H2 + CH4)

3. Drop-in liquid & gaseous fuels made from biomass or synthesized from H_2 + captured CO_2

Use of fuels decreases substantially in all scenarios, and by 2050 zero-carbon fuels and feedstocks come from a diversity of sources

Zero-carbon fuel options include

1. Fossil fuels plus negative emission offsets
2. Hydrogen made from biomass, NG w/CCS, or electrolysis
3. Synthesized fuels (from biomass or H_2 + captured CO_2)

Note: All fuel values reported in this slide pack are on HHV basis.

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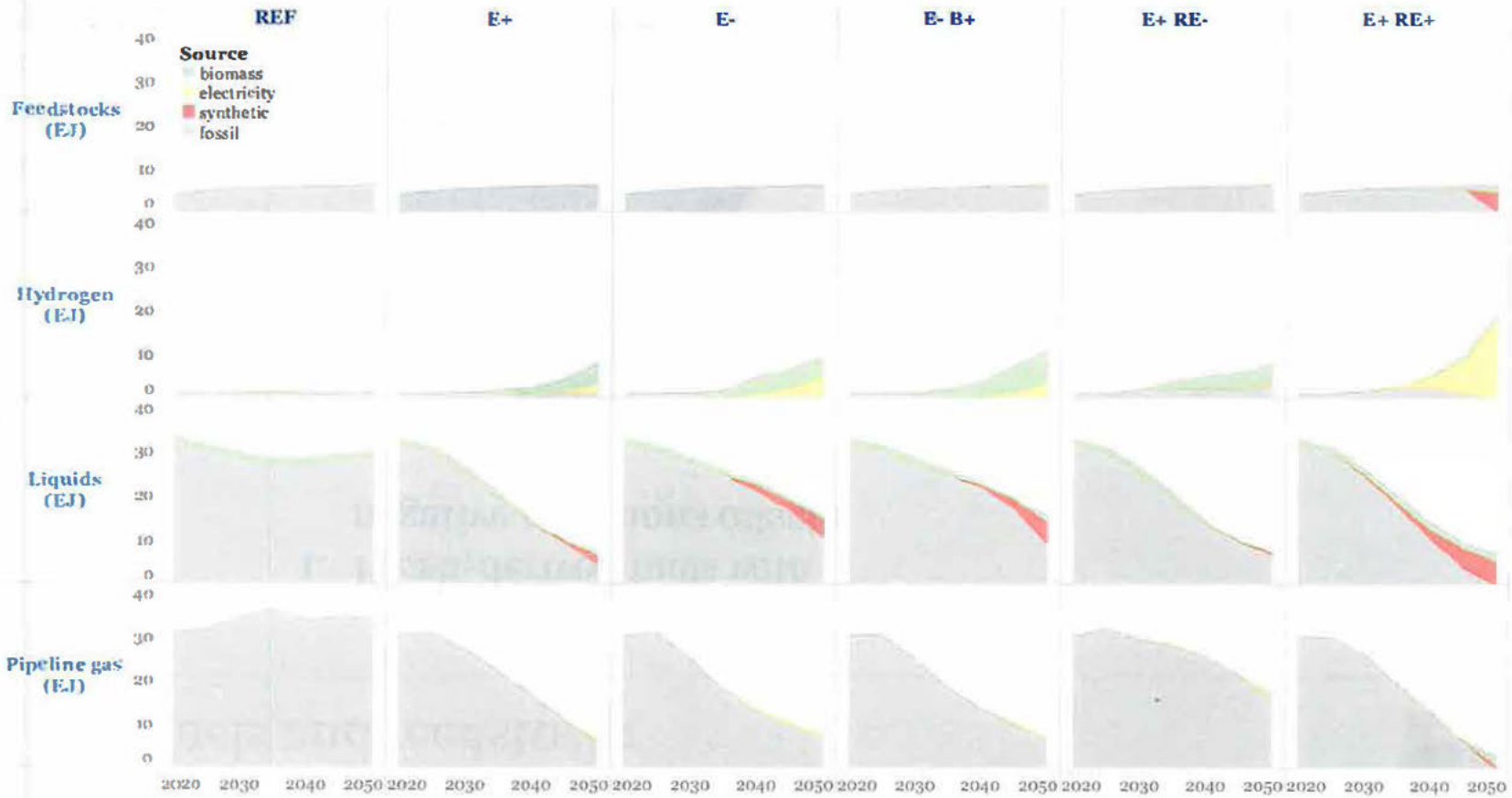
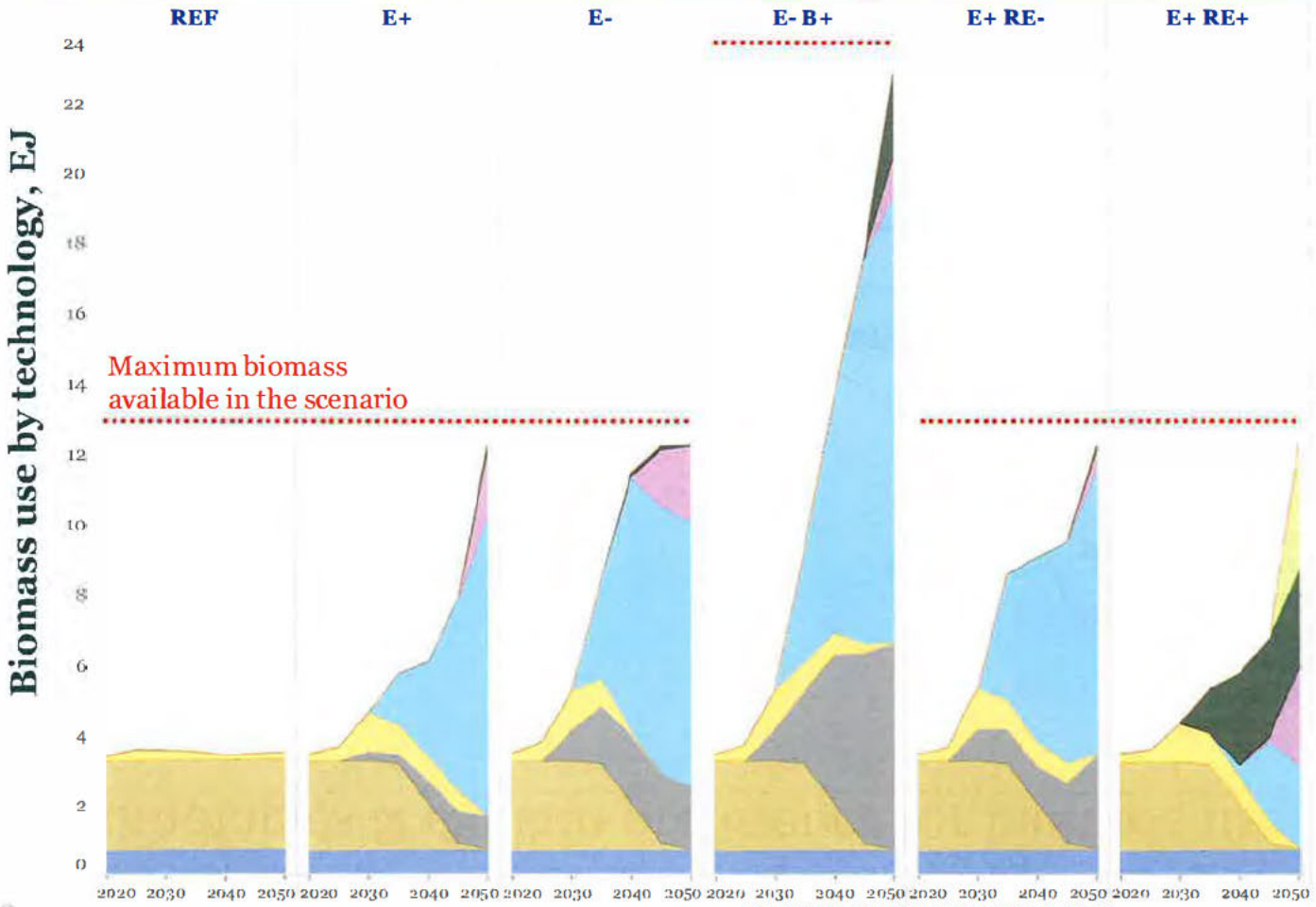
Mix of fuels and feedstocks by source



Essentially all available biomass is used in 2050. Rapid growth after 2030. H_2 from biomass with CO_2 capture is a key technology.



Biomass-energy conversion technologies

- biomass - > sng
- biomass -> sng w/cc
- biomass ft -> diesel
- biomass ft -> diesel w/ccu
- biomass pyrolysis
- biomass pyrolysis w/ccu
- hydrogen production w cc
- biomass electricity
- biomass w/ cc electricity
- ethanol
- demand-side

BECCS-H_2 is favored by:

- High marginal CO_2 emissions prices ($300 - $400/t by 2050).
- Higher value of biofuel vs. biopower.
- Highest energy delivered per unit CO_2 captured among all biofuel options.

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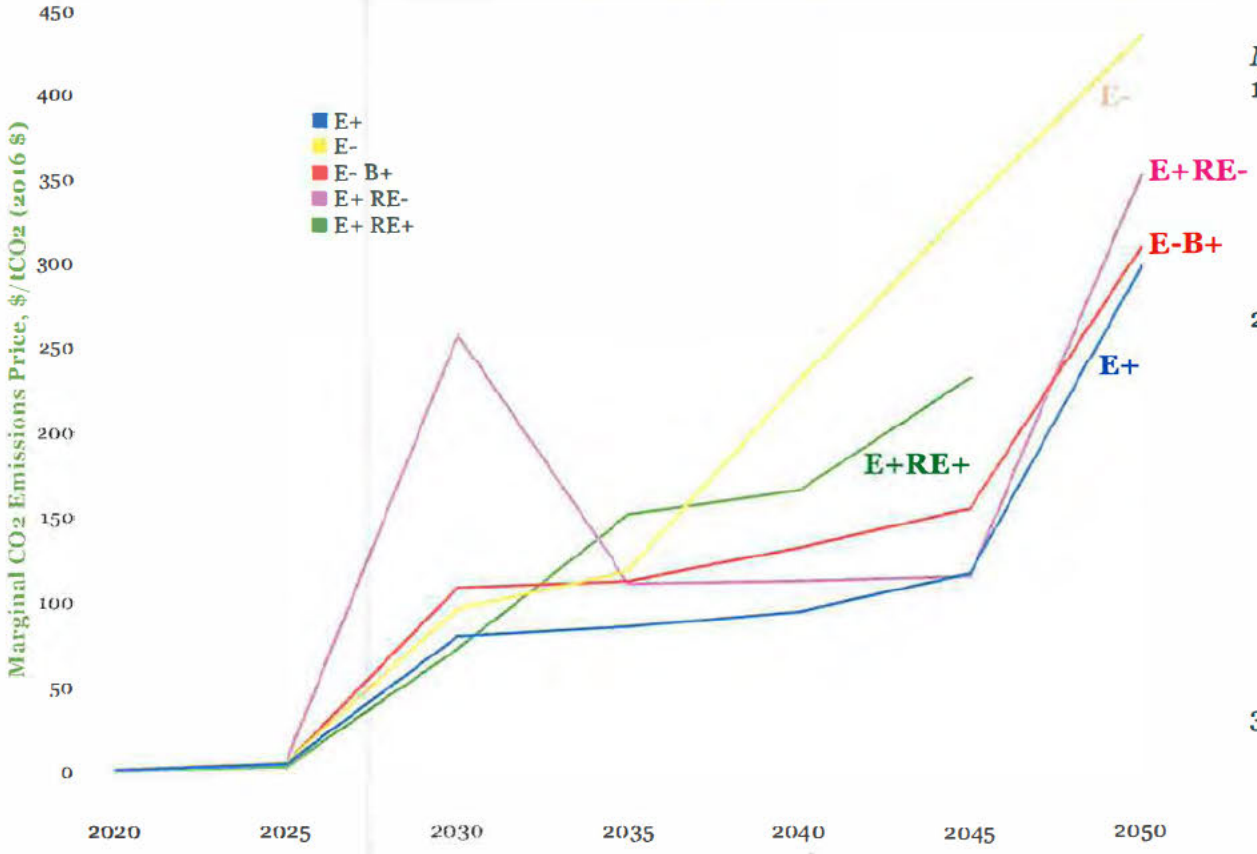
Note: All fuel values reported in this slide pack are on HHV basis.

High marginal CO_2 emission prices benefit negative emissions technologies & explain preference for biomass use in BECCS-H_2



Notes:

1) These prices represent overall supply-side system costs for reducing CO_2 emissions by one additional tonne. They do not take into consideration demand-side costs such as added costs for transport electrification in E+ compared with E-. As such, these prices should be interpreted as lower bound estimates of economy-wide carbon emission prices.
2) For E+RE-, the main factors contributing to the non-monotonic behavior from 2025-2035 are: (i) the exogenously imposed linear net-emissions reduction trajectory requires significant reductions by 2030, (ii) the limit on solar and wind power generation build rates means more nuclear and NG-CCS need to be installed; and what can be built of these by 2030 is costly, (iii) post-2030, things get easier because more nuclear and CCS can be built at lower cost, and the electrification of vehicles and buildings that started slowly in the 2020s (limited by stock turnover rates) begins to more significantly reduce fuel demands.
3) For E+RE+, no value is shown for 2050, because the constraint prohibiting fossil fuel use in 2050 is more binding than the annual emissions constraint, implying that the carbon price would (unrealistically) be zero in 2050.

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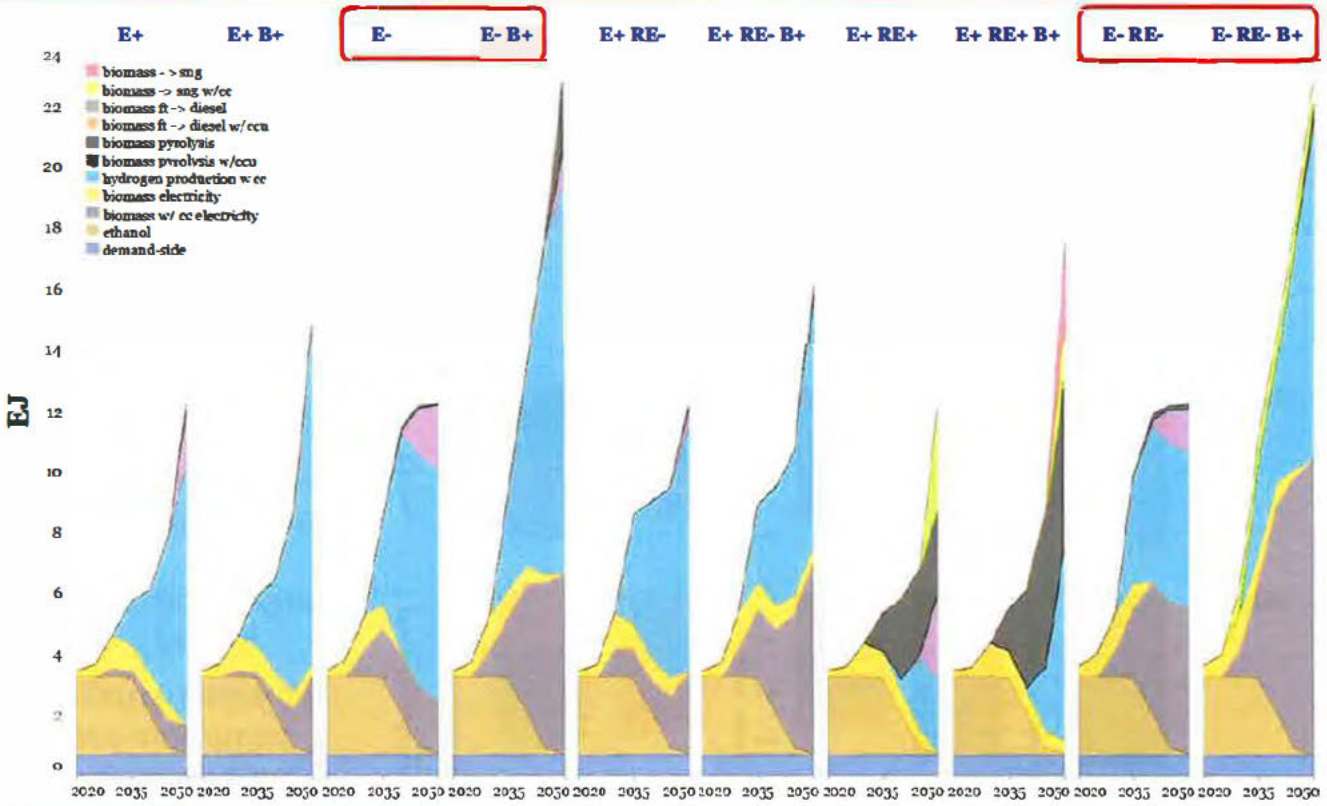
Carbon Mitigation Initiative

Higher biomass supply potential results in more biomass use for electricity and hydrogen generation

Biomass is a key resource in most scenarios.

- With the lower biomass supply potential, all available biomass is utilized in all 5 scenarios shown here, including E-RE- (run as a sensitivity to E+RE-).
- With the high biomass supply potential :
  - all available biomass is used in E-B+ and E-RE-B+ cases, which underlines the importance of electrification in reducing reliance on biomass in net-zero pathways.
  - Most of the additional biomass in E+RE-B+, E+RE+B+, and E-RE-B+ is used to produce additional negative emissions via power generation or H_2 production.



Input assumptions that vary between cases		
	E+, E-, E+RE-, E+RE+	E+B+, E-B+, E+RE-B+, E+RE+B+
Biomass potential (by 2050)	0.7 Gt/y (13 EJ)	1.3 Gt/y (24 EJ)

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If no new biomass use is allowed, more oil and gas are used and direct air capture and sequestration of CO_2 increase to compensate



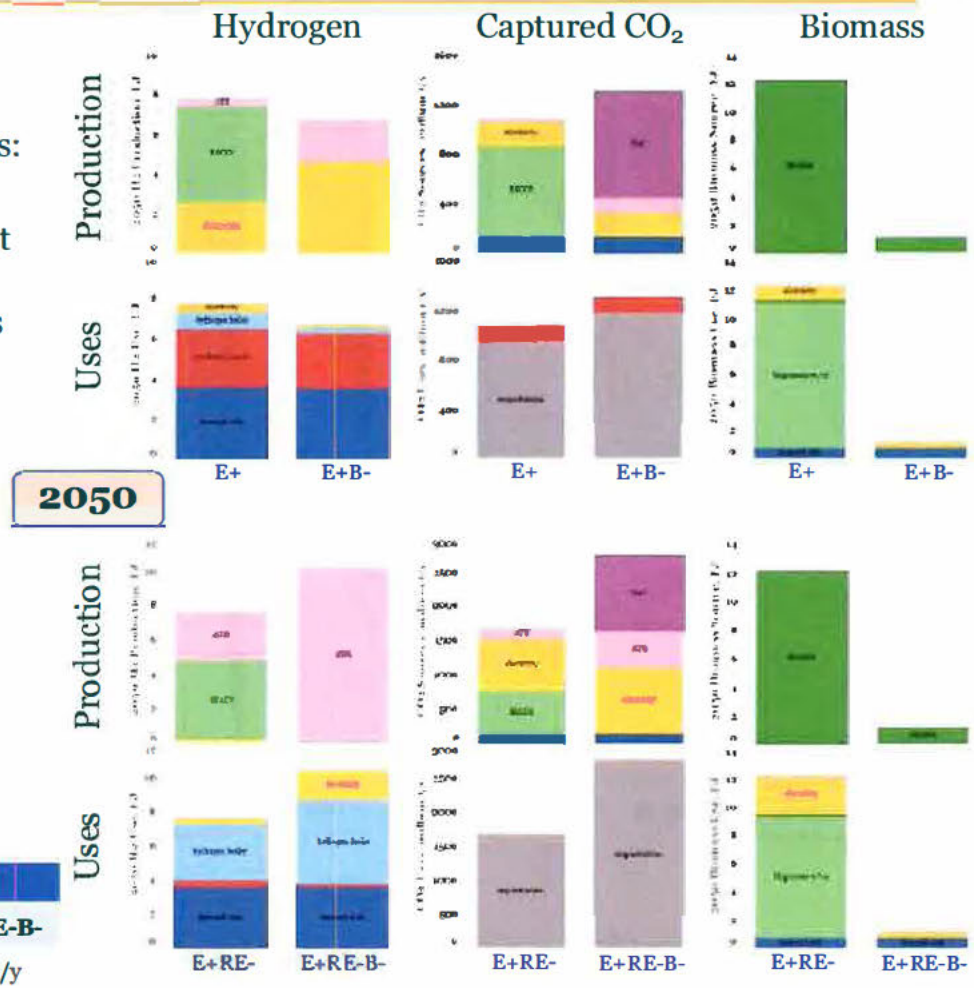
Not allowing new biomass removes a key pathway for making net-zero or net-negative emission fuels and leaves only direct air capture (DAC) as an option for achieving negative emissions:

For the E+ case with no new biomass (E+ B-, upper panel)

- electrolysis and natural gas reforming with CO_2 capture offset the loss of H_2 production from biomass.
- DAC use increases dramatically to offset the added emissions from greater natural gas use and negative emissions from BECCS. Stored CO_2 increases.
- 30-yr NPV of energy-supply system costs increase ~5%.

For E+RE- with no new biomass (E+RE- B-, lower panel)

- More hydrogen is produced and all by natural gas reforming with CO_2 capture. More H_2 is used for power generation and industrial steam generation; less for liquid fuels synthesis.
- DAC deployments starts in the early 2030s and ramps up dramatically by 2050, along with CO_2 capture from gas-fired power plants.
- CO_2 storage nearly doubles relative to E+ RE-.
- 30-yr NPV of energy-supply system cost increases by ~25%.

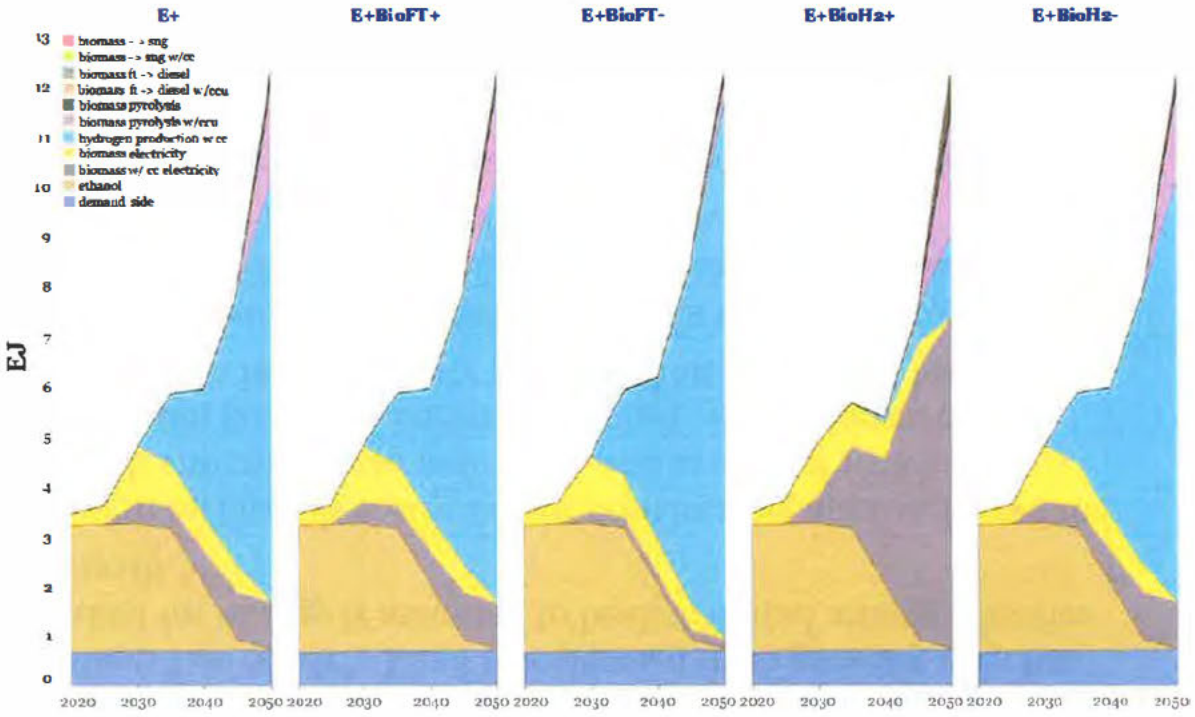


Input assumptions that vary between cases	E+	E+ B-	E+ RE-	E+ RE-B-
Biomass potential (increase from today to 2050)	0.7Gt/y	0 Gt/y	0.7Gt/y	0 Gt/y

Higher capital costs for biomass conversion to hydrogen drives more biomass use for electricity, but not for bio-derived liquid fuels

Gasification-based integrated biomass conversion to Fischer-Tropsch fuels or H_2 with CO_2 capture are pre-commercial technologies, with inherently uncertain capital costs for future commercial-scale plants. Sensitivity runs tested the impact of 50% higher and 20% lower assumed capital costs for these technologies:

- Neither higher nor lower biomass-FT costs impacted results, because other routes to liquid fuels are less costly for meeting liquid fuel demands within carbon emission constraints.
- A similar result is observed with lower capital costs for biomass-H_2 with CO_2 capture.
- But with higher costs for biomass-H_2, biomass use shifts away from H_2 production to electricity generation with CO_2 capture. Notably, biomass-FT technology is still not deployed even in this case.
- The 30-yr NPV of energy-supply system costs are similar for all cases shown here



Input assumptions that vary between cases					
$/kW_{out,HHV}$ in 2050	E+	E+ BioFT+	E+ BioFT-	E+ BioH2+	E+ BioH2-
BECCS-H_2 capital cost	2700	2700	2700	4050	2160
Biomass FT capital cost	3962	5984	3172	3962	3962

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Spatial downscaling and analysis of bioenergy production and use in the E+ pathway



Summary of this section

- For the E+ pathway, the geographic distribution of agricultural and forestry residues used for energy is based on county-level projections from the "Billion Ton Study". Land transitioned from growing corn for ethanol to growing perennial grasses or equivalent for energy is assumed to be distributed among counties in proportion to their corn production level in 2018.*
- Transporting biomass long distances to conversion facilities is costly, so our downscaling approach uses the county-level biomass supply estimates to establish 100 mile x 100 mile cells, within each of which all available biomass is assumed to be used in conversion facilities located in that cell. Each bioconversion facility, regardless of technology, is assumed to have an input capacity of 0.7 million t(dry)/y of biomass.
- Bioconversion capacity within a given RIO modeling region is deployed first in cells within that region that have the highest biomass supply density (as a surrogate for lowest biomass feedstock cost), and facilities that capture CO_2 are sited near CO_2 storage reservoirs or pipelines (see CO_2 pipeline maps later).
- Bioconversion facilities are sited primarily in states in the upper Midwest and secondarily in the Southeast.
- The cumulative investment in bioconversion capacity to 2050 is about 750 B$ nationwide, and farmer revenues from sale of biomass for energy are more than double today's revenues for corn sold into ethanol production.

* The average rain-fed harvestable yield (t/ha/y, dry basis) of perennial energy grasses on former corn-growing land assumed in the modeling here is about ¾ of today's U.S. average whole-plant yield for corn. Conceptually, therefore, the biomass assumed to be supplied from converted corn-growing lands could equivalently be whole-corn-plant biomass with ¼ of the material left on the field for soil maintenance purposes.

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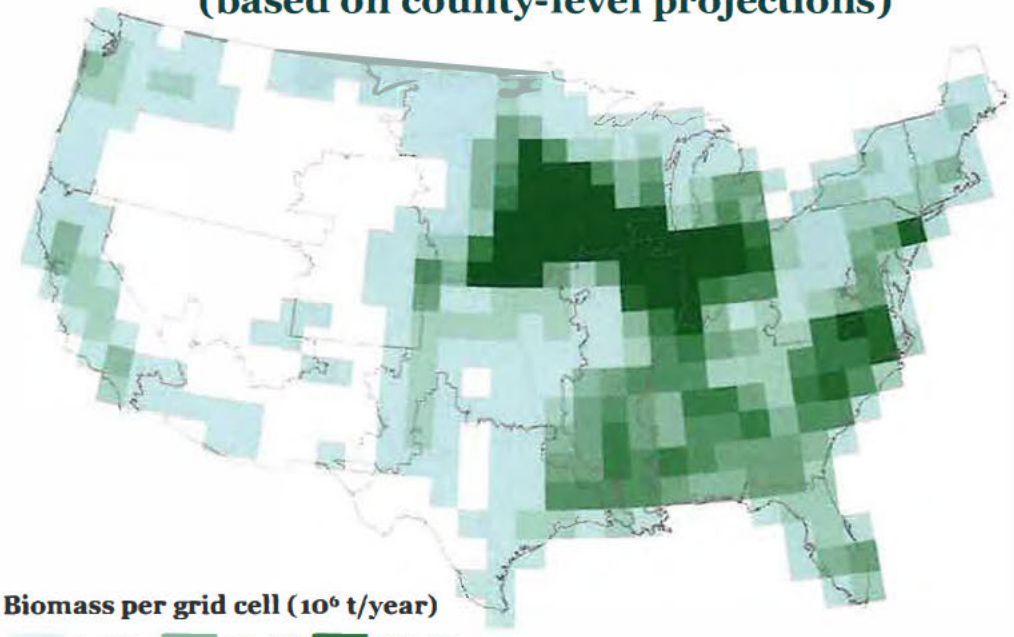
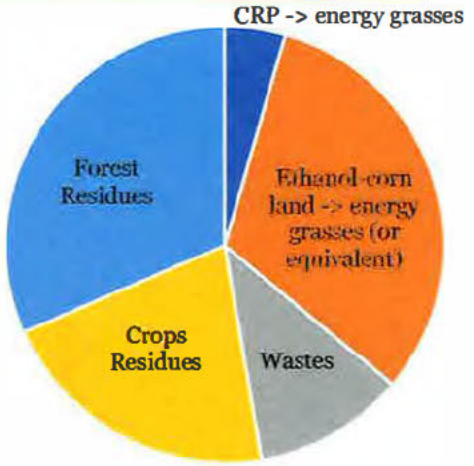
E+ Scenario: Biomass supply with no increase in land use for energy. Midwest and Southeast are largest sources.

2050 biomass availability, 100 x 100 mi cells (based on county-level projections)



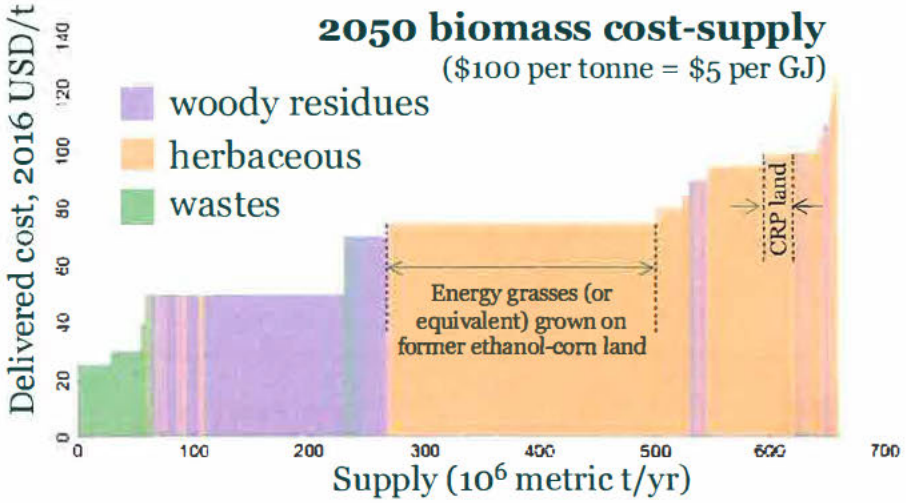
Note: All fuel values reported in this slide pack are on HHV basis.

2050 supply by resource (13 EJ total)



2050 biomass cost-supply

($100 per tonne = $5 per GJ)



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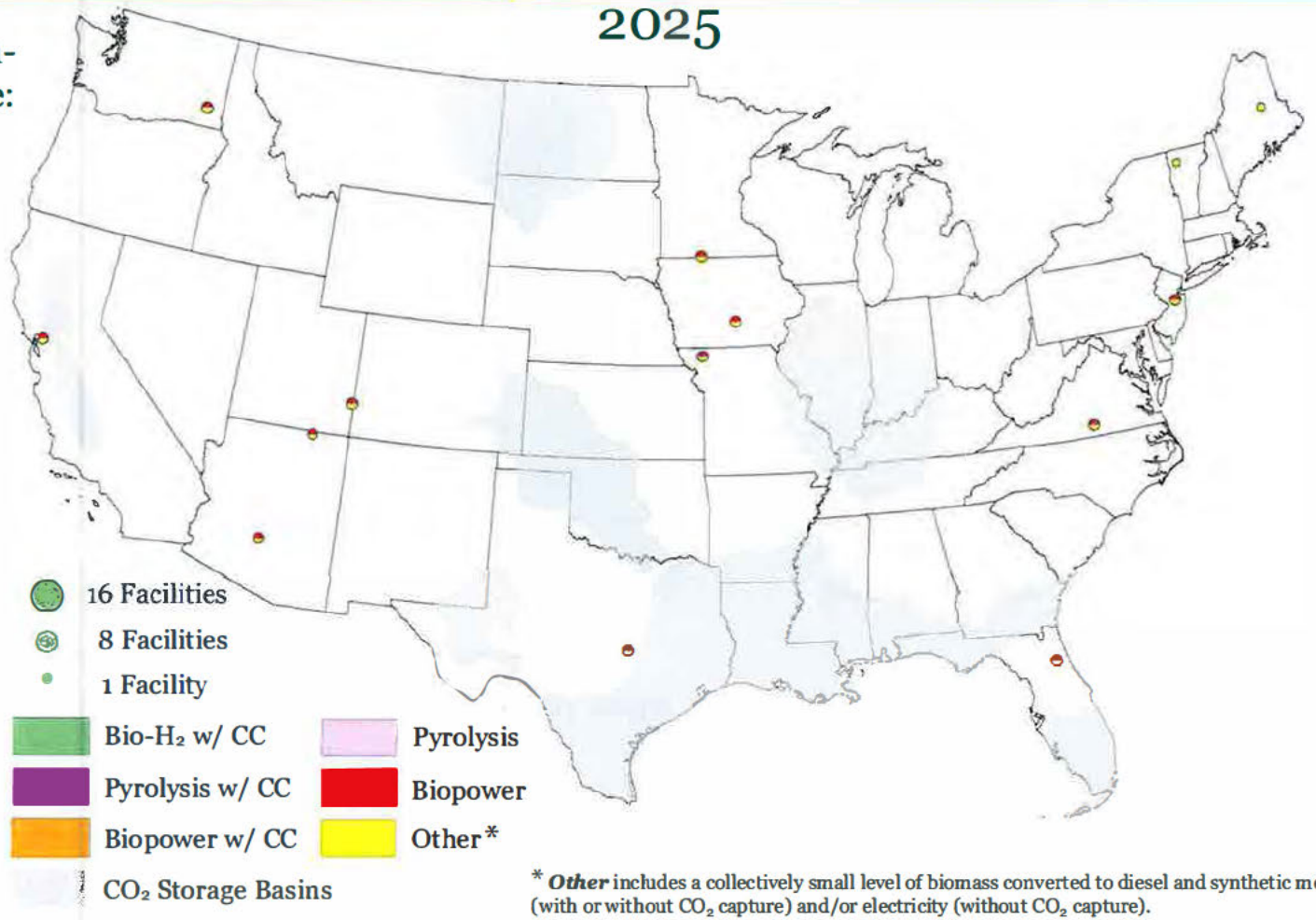
Evolution of the bioconversion industry, E+ scenario

Total annual non-food biomass use:
- 44 million t
- 0.9 EJ



* ***Other*** includes a collectively small level of biomass converted to diesel and synthetic methane (with or without CO_2 capture) and/or electricity (without CO_2 capture).

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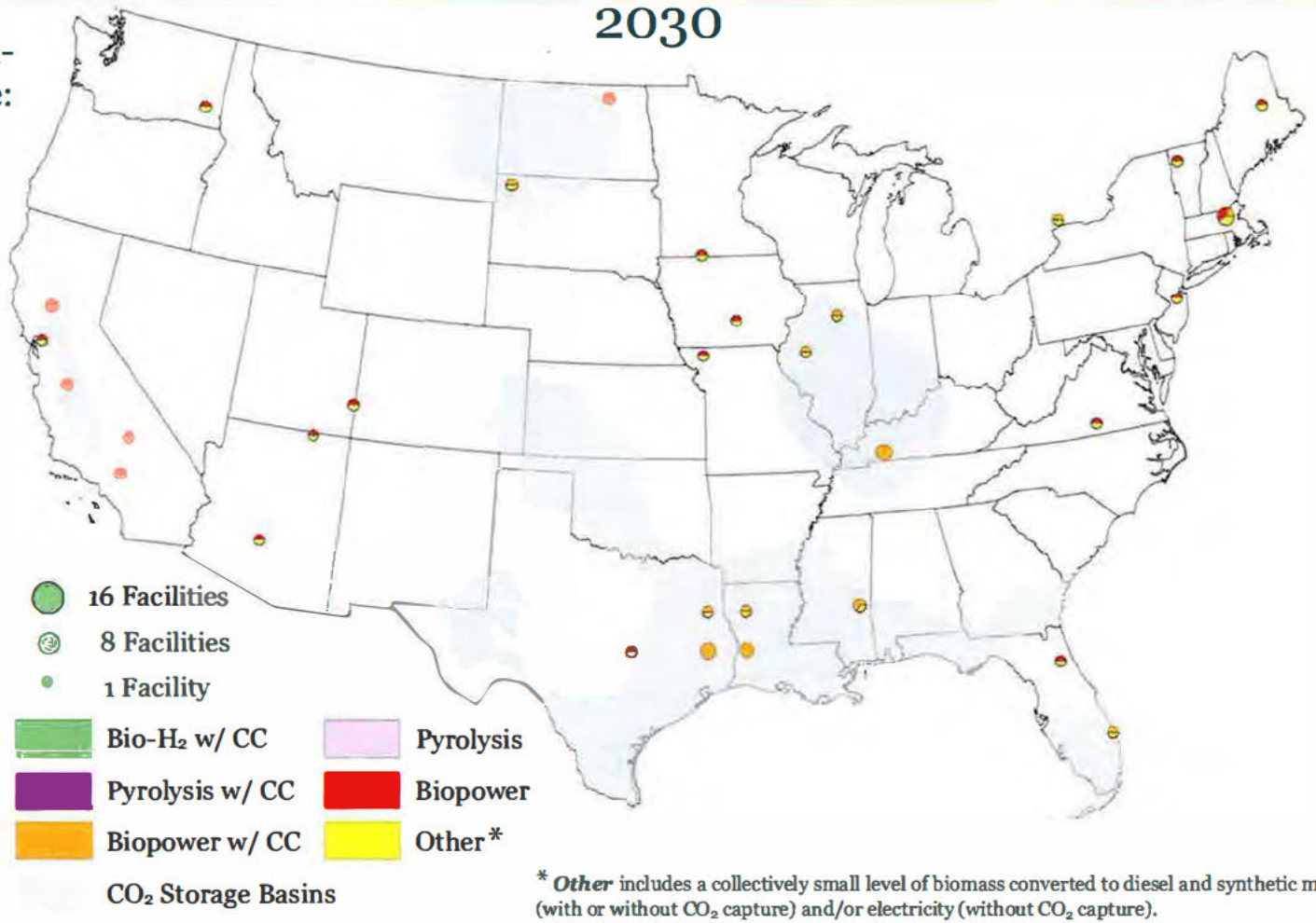
Evolution of the bioconversion industry, E+ scenario

Total annual non-food biomass use:
- 79 million t
- 1.6 EJ



* ***Other*** includes a collectively small level of biomass converted to diesel and synthetic methane (with or without CO_2 capture) and/or electricity (without CO_2 capture).

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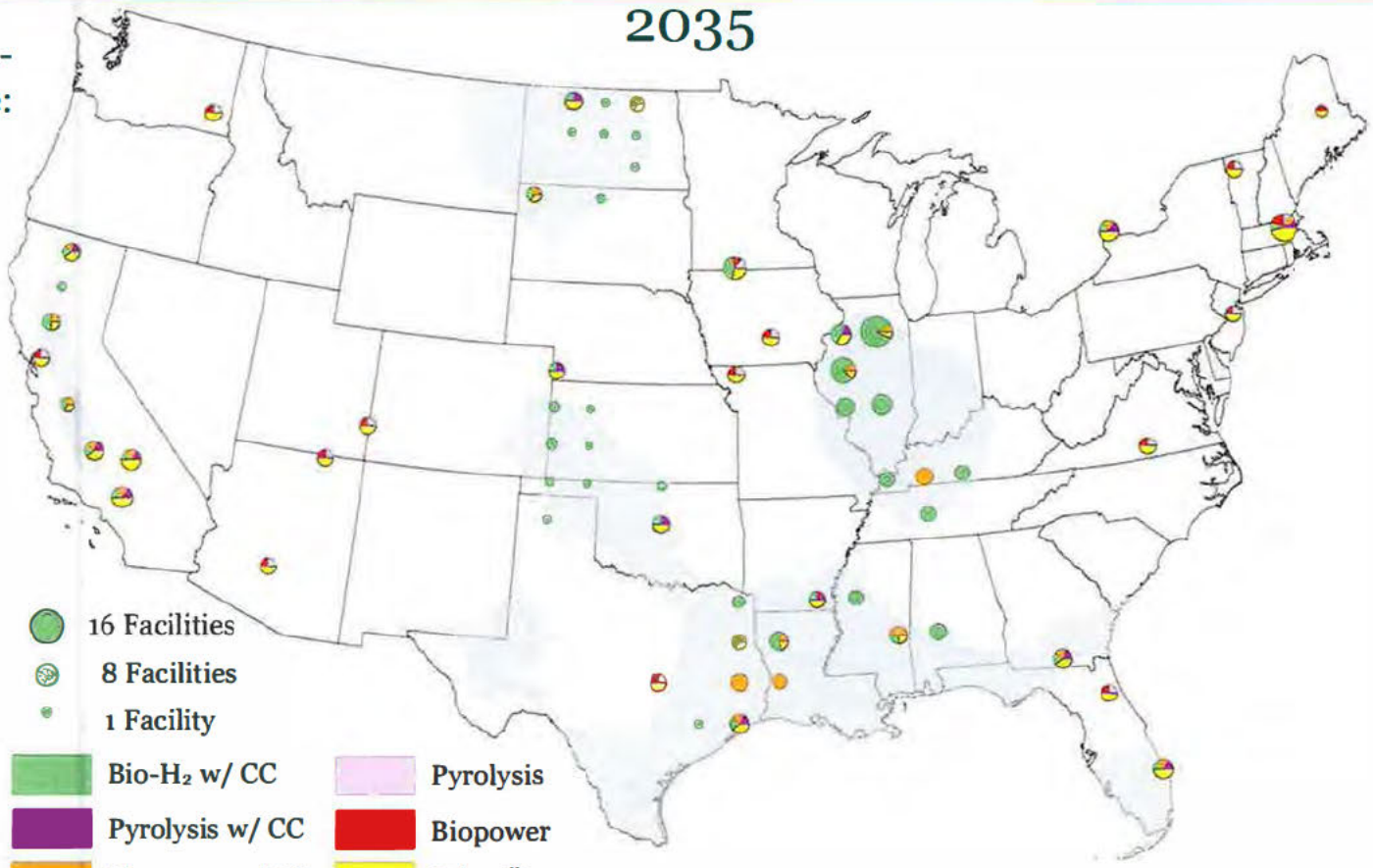
Evolution of the bioconversion industry, E+ scenario

Total annual non-food biomass use:
- 145 million t
- 2.9 EJ



* ***Other*** includes a collectively small level of biomass converted to diesel and synthetic methane (with or without CO_2 capture) and/or electricity (without CO_2 capture).

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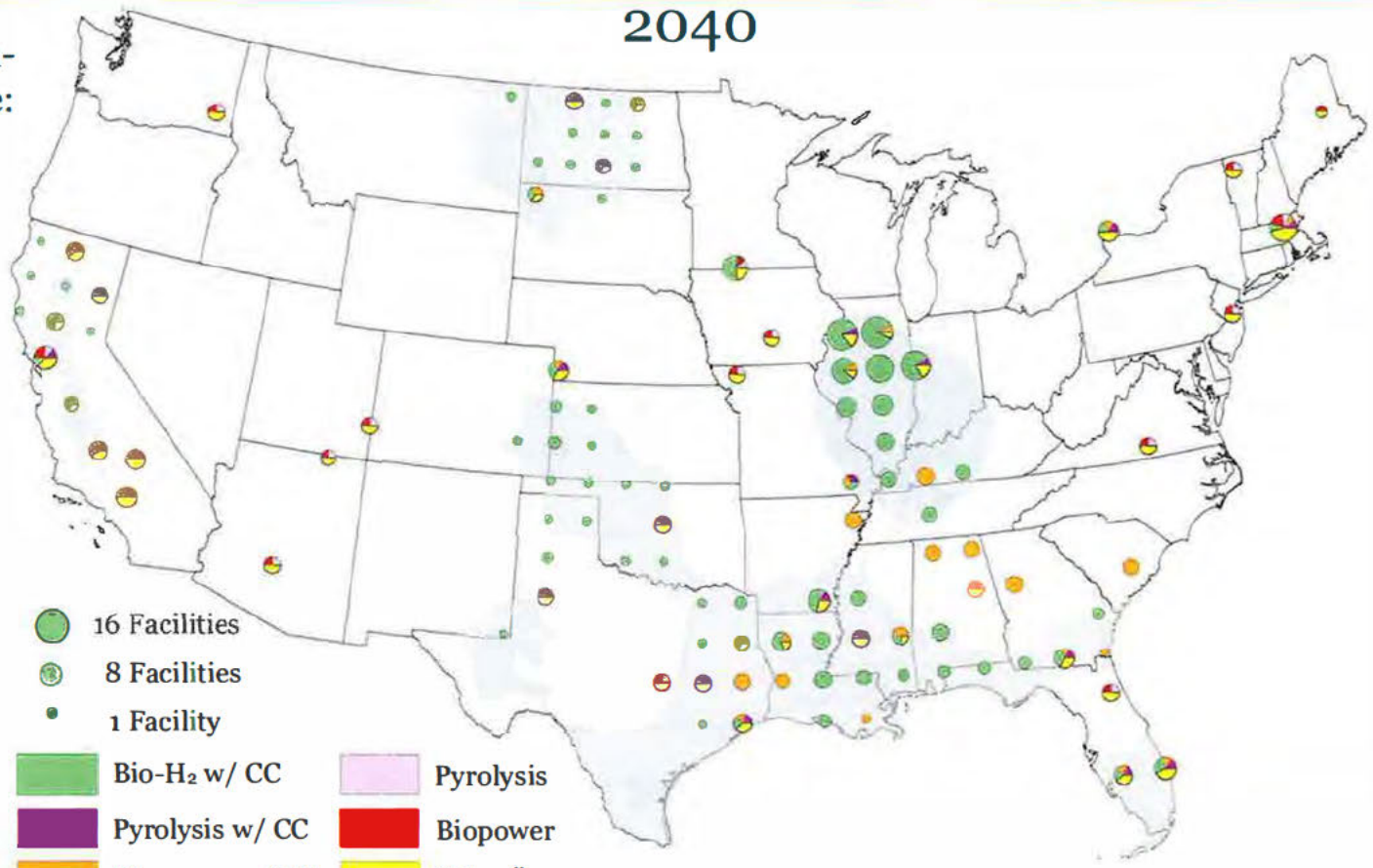
Evolution of the bioconversion industry, E+ scenario

Total annual non-food biomass use:
- 223 million t
- 4.4 EJ



* ***Other*** includes a collectively small level of biomass converted to diesel and synthetic methane (with or without CO_2 capture) and/or electricity (without CO_2 capture).

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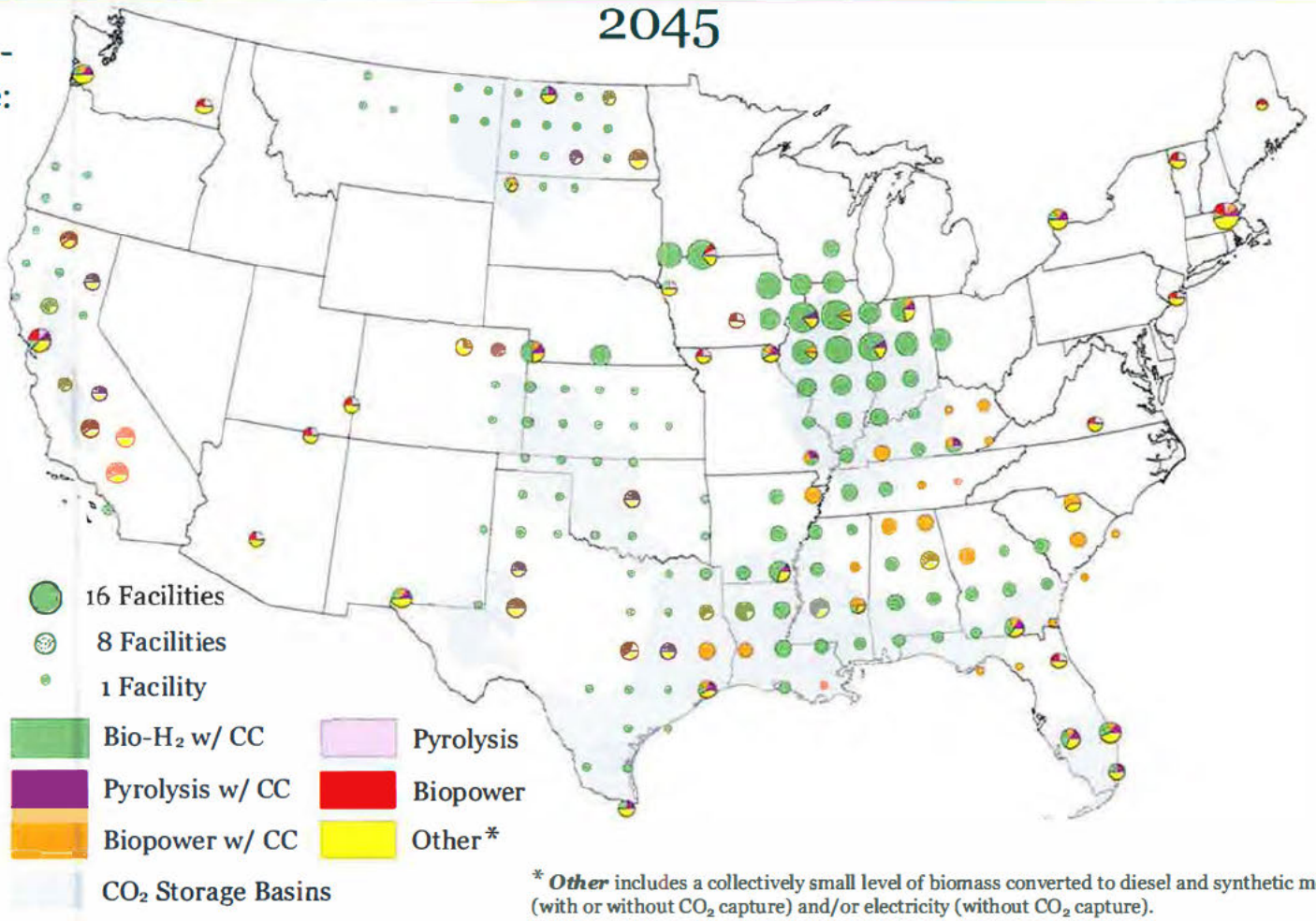
Evolution of the bioconversion industry, E+ scenario

Total annual non-food biomass use:
- 375 million t
- 7.4 EJ



* ***Other*** includes a collectively small level of biomass converted to diesel and synthetic methane (with or without CO_2 capture) and/or electricity (without CO_2 capture).

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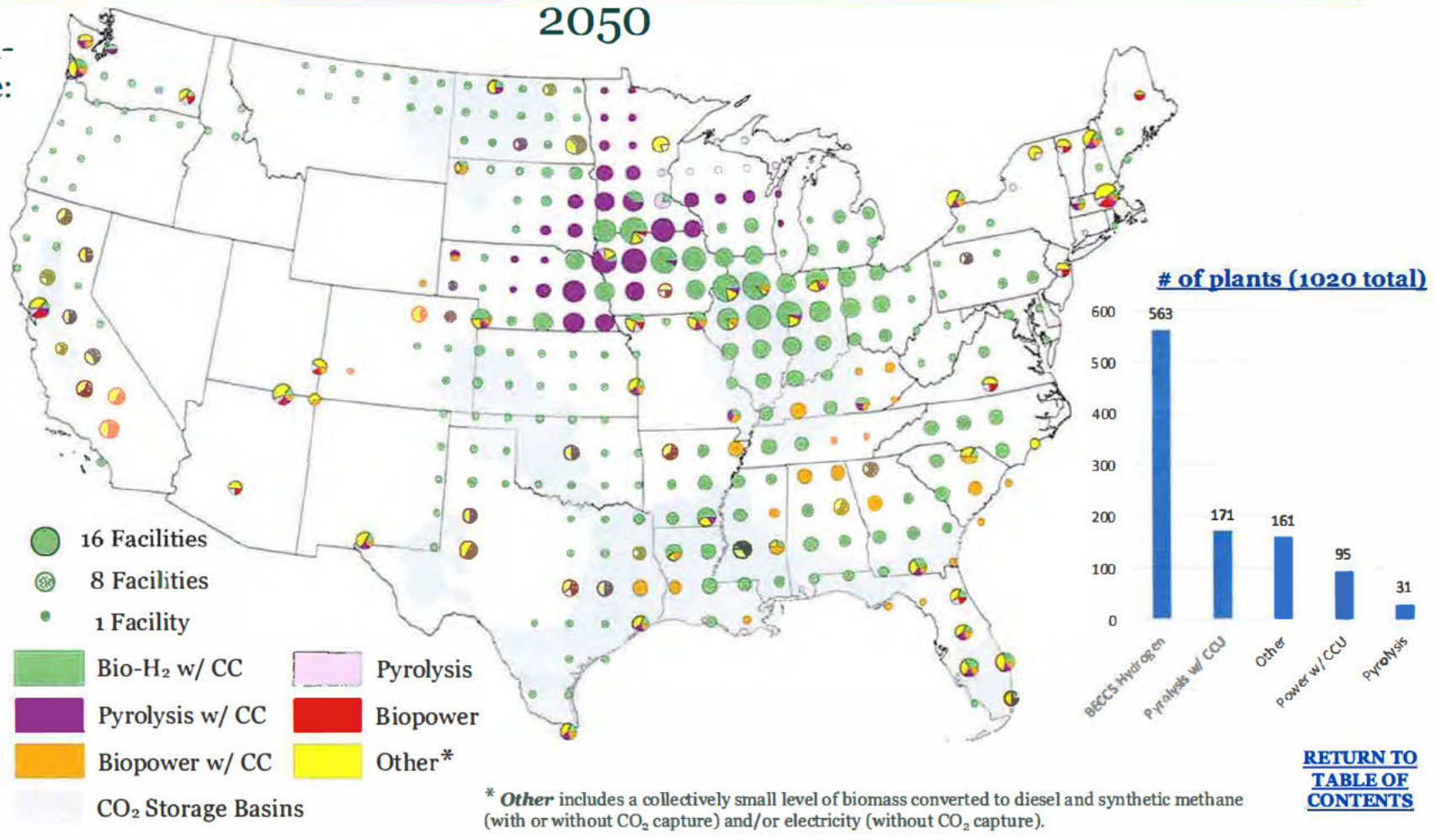
Evolution of the bioconversion industry, E+ scenario

Total annual non-food biomass use:
- 618 million t
- 12.2 EJ



* ***Other*** includes a collectively small level of biomass converted to diesel and synthetic methane (with or without CO_2 capture) and/or electricity (without CO_2 capture).

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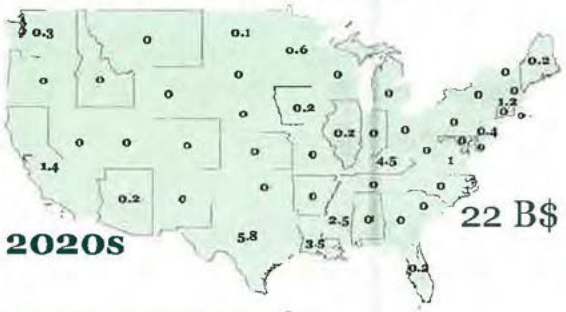
750 B$ capital invested in bioconversion by 2050, largely in Midwest and Southeast. Biomass purchases grow, displacing corn for ethanol.



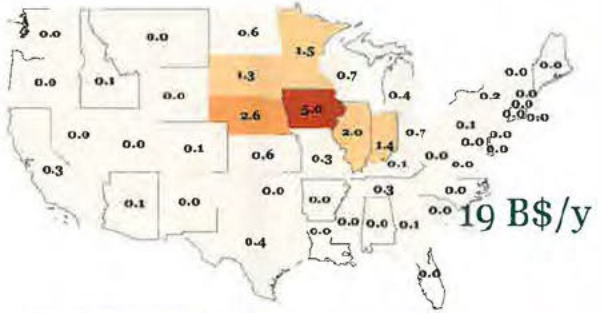
Capital invested (B$)*

Biomass purchases (B$/y)

Corn (for eth.) purchases (B$/y)

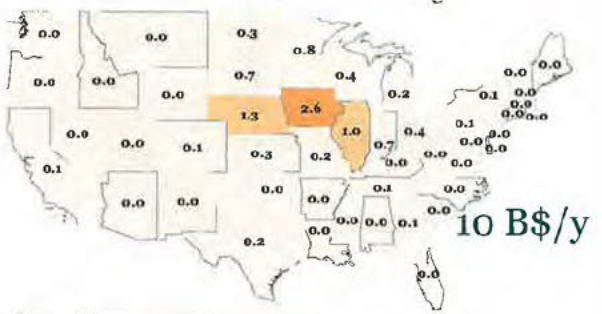






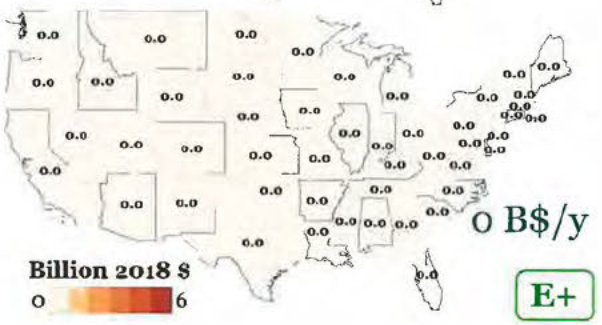












E+

* In plants coming online in indicated decade.

Spatial downscaling and analysis of bioenergy production and use in the E- B+ pathway

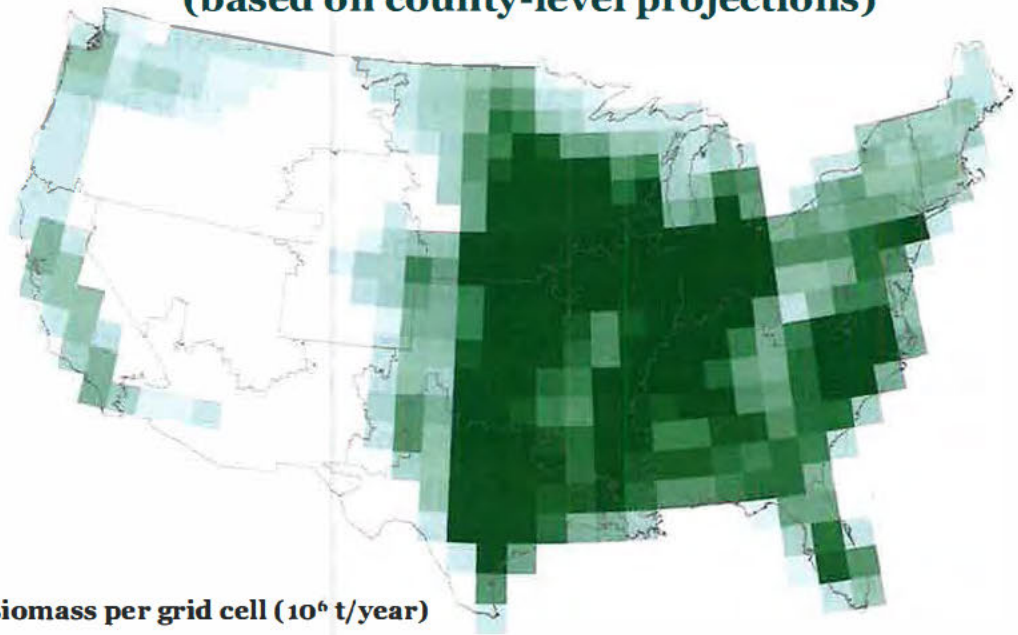


Summary of this section

- For the E- B+ pathway, the geographic distribution of biomass supplies, including dedicated energy crops grown on converted food-agriculture land, is based on county-level projections from the "Billion Ton Study". Additionally, production of dedicated energy grasses on lands converted from growing corn for ethanol is assumed to be distributed among counties in proportion to their corn production level in 2018.
- Transporting biomass long distances to conversion facilities is costly, so our downscaling approach uses the county-level biomass supply estimates to establish 100 mile x 100 mile cells, within each of which all available biomass is assumed to be used in conversion facilities located in that cell. Each bioconversion facility, regardless of technology, is assumed to have an input capacity of 0.7 million t(dry)/y of biomass.
- Bioconversion capacity within a given RIO modeling region is deployed first in cells within that region that have the highest biomass supply density (as a surrogate for lowest biomass feedstock cost), and facilities that capture CO_2 are sited near CO_2 storage reservoirs or pipelines (see CO_2 pipeline maps later).
- Bioconversion facilities are sited primarily in states in the upper Midwest and secondarily in the Southeast.
- The cumulative investment in bioconversion capacity to 2050 is 1.4 T$ nationwide, and farmer revenues from sale of biomass for energy are more than quintuple today's revenues for corn sold into ethanol production.

E- B+ Scenario: Biomass supply is nearly doubled via conversion of some pasture and cropland to energy crops.

2050 biomass availability, 100 x 100 mi cells (based on county-level projections)



Biomass per grid cell (10^6 t/year)

0 - 0.5	1.5 - 2.0	3.0 - 3.5	4.5 - 5.0
0.5 - 1.0	2.0 - 2.5	3.5 - 4.0	5.0 - 15.8
1.0 - 1.5	2.5 - 3.0	4.0 - 4.5	

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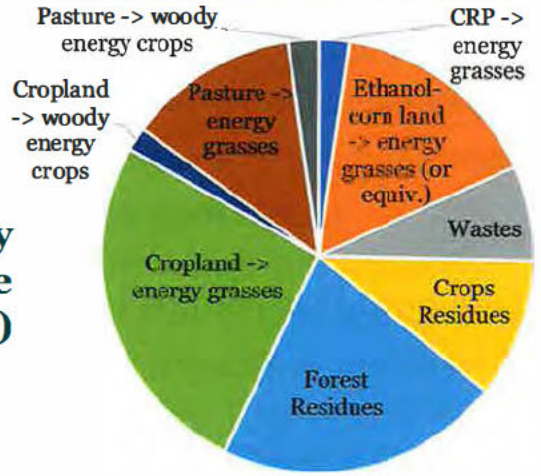
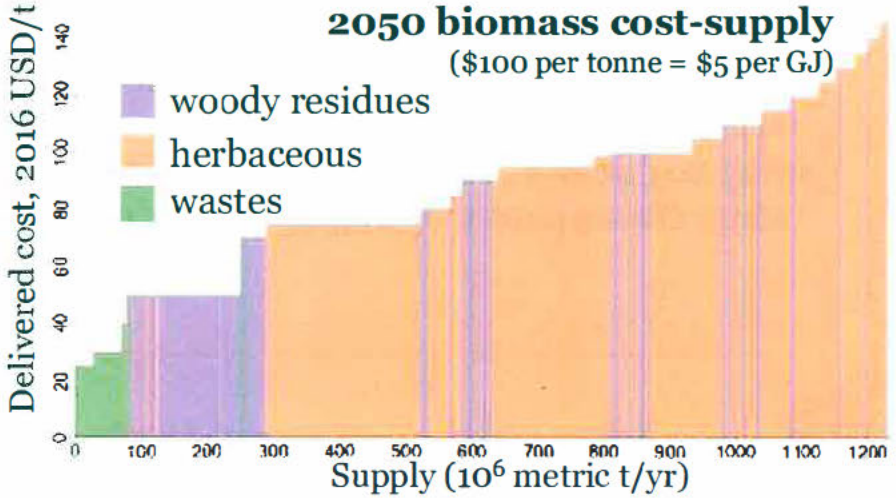
Note: All fuel values reported in this slide pack are on HHV basis.

2050 supply by resource (24 EJ total)



2050 biomass cost-supply

($100 per tonne = $5 per GJ)



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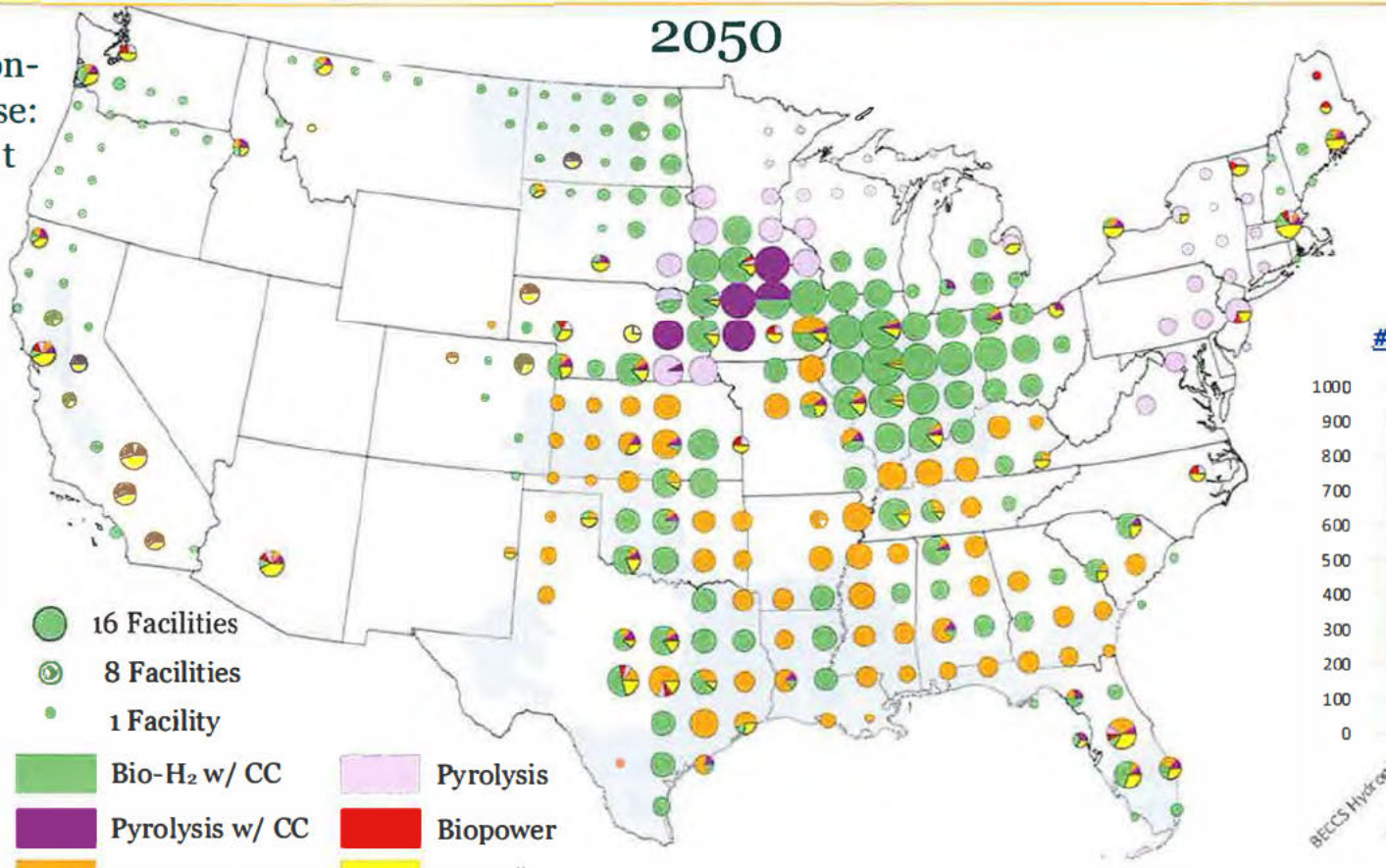
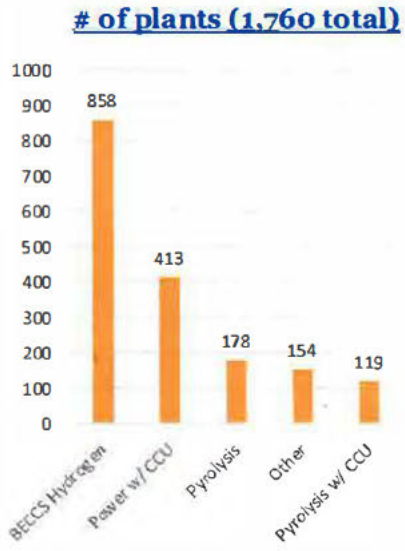
Bioconversion industry, E- B+ scenario

Total annual non-food biomass use:
- 1,153 million t
- 22.8 EJ





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* ***Other*** includes a collectively small level of biomass converted to diesel and synthetic methane (with or without CO_2 capture) and/or electricity (without CO_2 capture).

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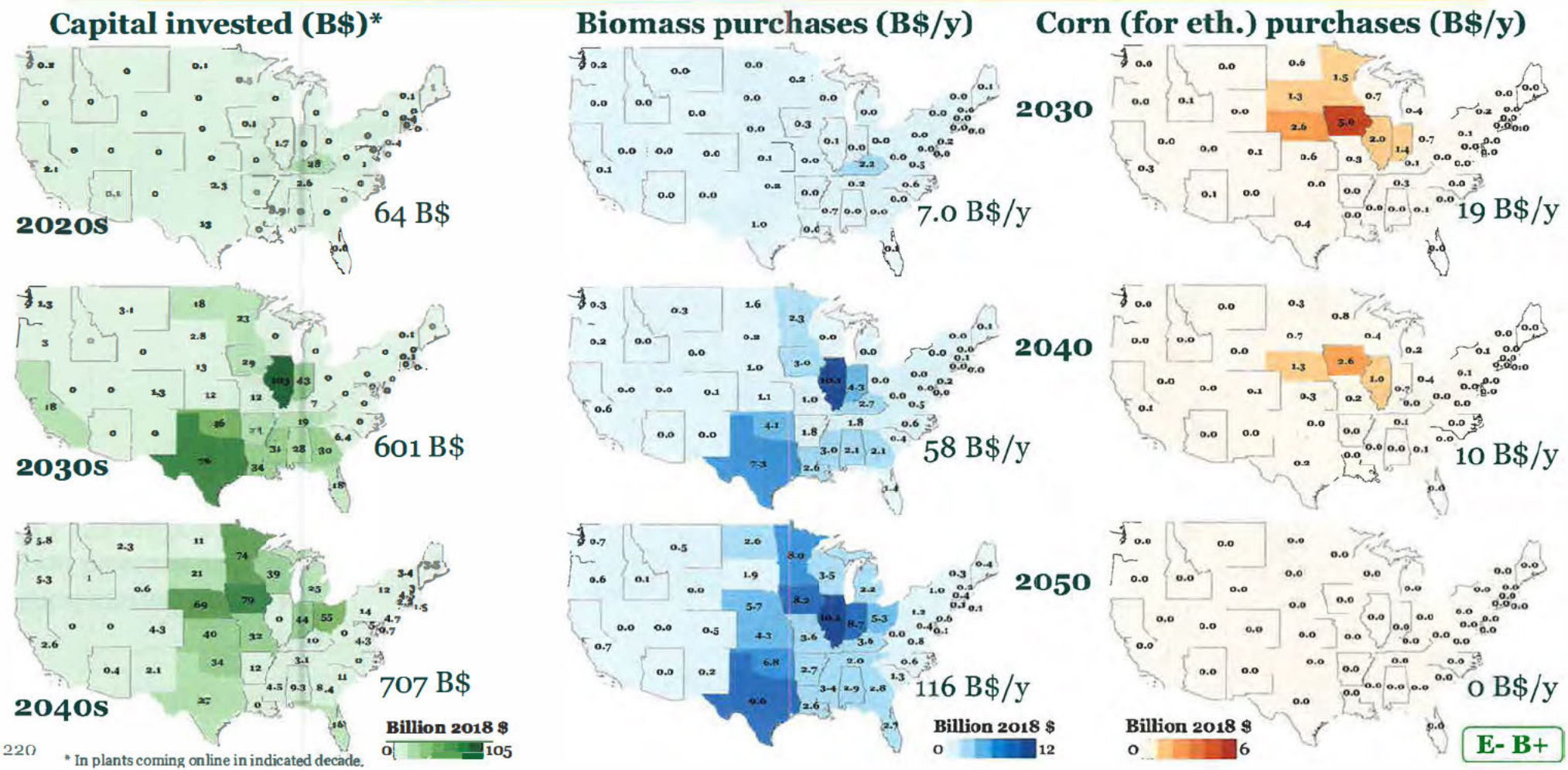
1.4 T$ capital invested in bioconversion by 2050, largely in Midwest and Southeast. Biomass purchases grow, displacing corn for ethanol.





* In plants coming online in indicated decade.

E- B+

Hydrogen production and use

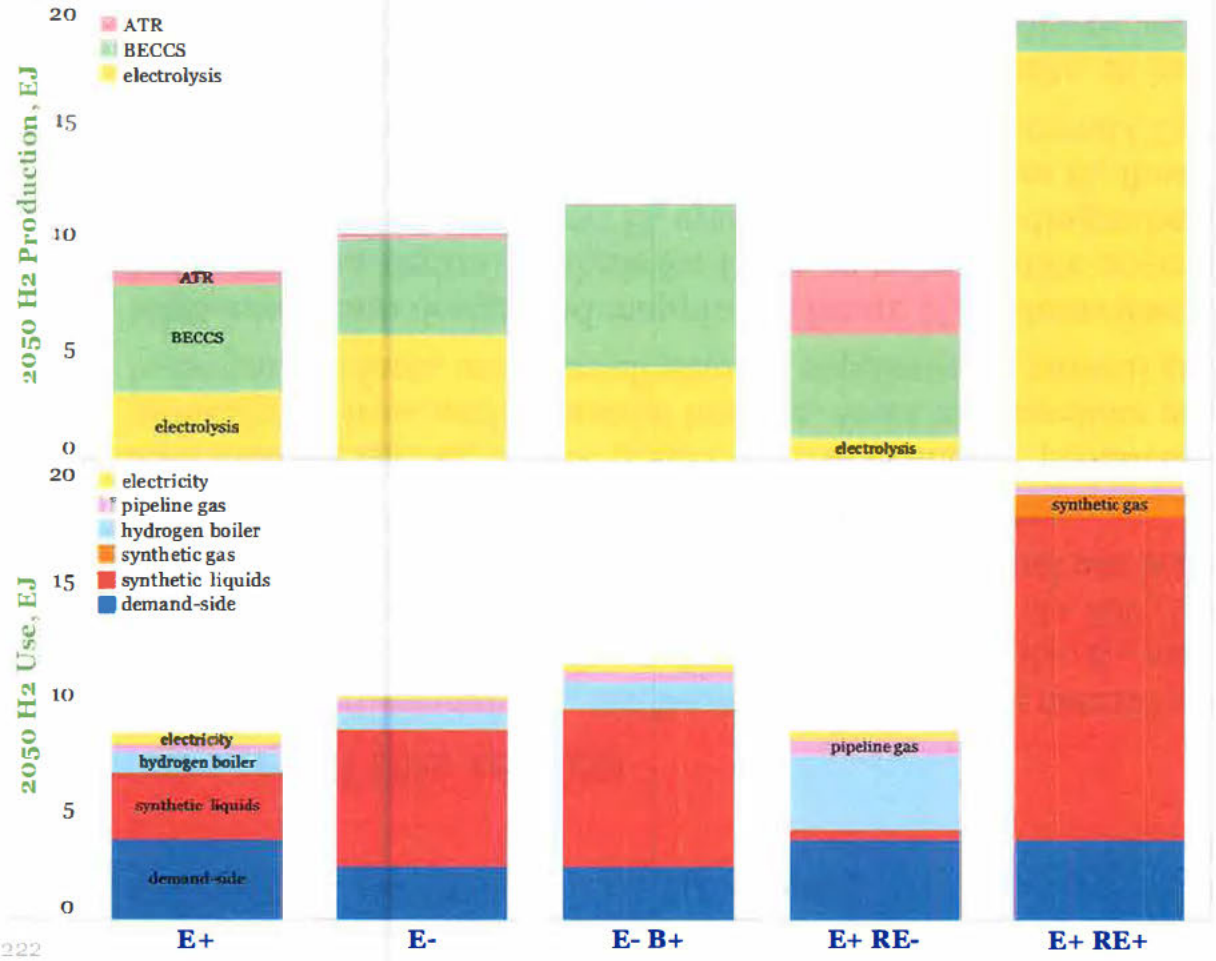


Summary of this section

- In the net-zero models, H_2 can be made by reforming natural gas (without or with CO_2 capture), gasifying biomass (with CO_2 capture), or electrolysis of water. E+, E-, and E- B+ all favor H_2 from a mix of biomass and electrolysis. H_2 from natural gas is prominent in E+ RE-, because electrolysis is less cost effective. In E+ RE+, electrolysis dominates by 2050 because fossil fuel use is disallowed and most biomass is converted into pyrolysis oils used for petrochemicals production.
- As a final energy, H_2 is used in fuel cell trucks and for producing ammonia and other chemicals, direct reduction of iron, and industrial heating. As an intermediate energy, H_2 is an input to synthesis of hydrocarbon fuels, and a small amount supplements natural gas use in gas turbine power generation.
- High-resolution design and mapping of future H_2 systems was not done (except for biomass H_2, as above), but coarse (14-region) analysis for E+ gives an indicative 2050 snapshot of possible future geographic distribution of this industry: H_2 systems begin expanding substantially only starting in the mid-2030s, reaching total H_2 volumes in 2050 more than six times H_2 flows in the U.S. today. In E+ RE+, H_2 flows are more than twice as large, with most H_2 used with captured CO_2 to synthesize hydrocarbon fuels.
- Many industrial H_2 users would likely produce H_2 onsite, as happens today. Distributed users might be served by regional pipeline networks and/or truck delivery, as is also the case in some regions today. Vignettes of notional future industry-serving regional H_2 pipelines are sketched to illustrate.

8 to 19 EJ of H_2 are produced in 2050, with volume flows of 0.8x to 2.2x today's U.S. natural gas use (35 EJ) at pipeline pressure





H_2 sources

ATR = autothermal reforming of natural gas with CO_2 capture.

BECCS = biomass gasification to H_2 with CO_2 capture (negative net emissions).

Electrolysis = water splitting using electricity

H_2 uses

Electricity = H_2 burned in gas turbines in high "hythane" blend with CH_4 (50% limit by energy).

Pipeline gas = H_2 used for "hythane" blend in CH_4 pipeline (5% limit by energy).

H_2 boiler = industrial steam generation.

Synthetic gas = CH_4 synthesis from H_2 and CO_2.

Synthetic liquids = Fischer Tropsch fuels from H_2 + CO_2.

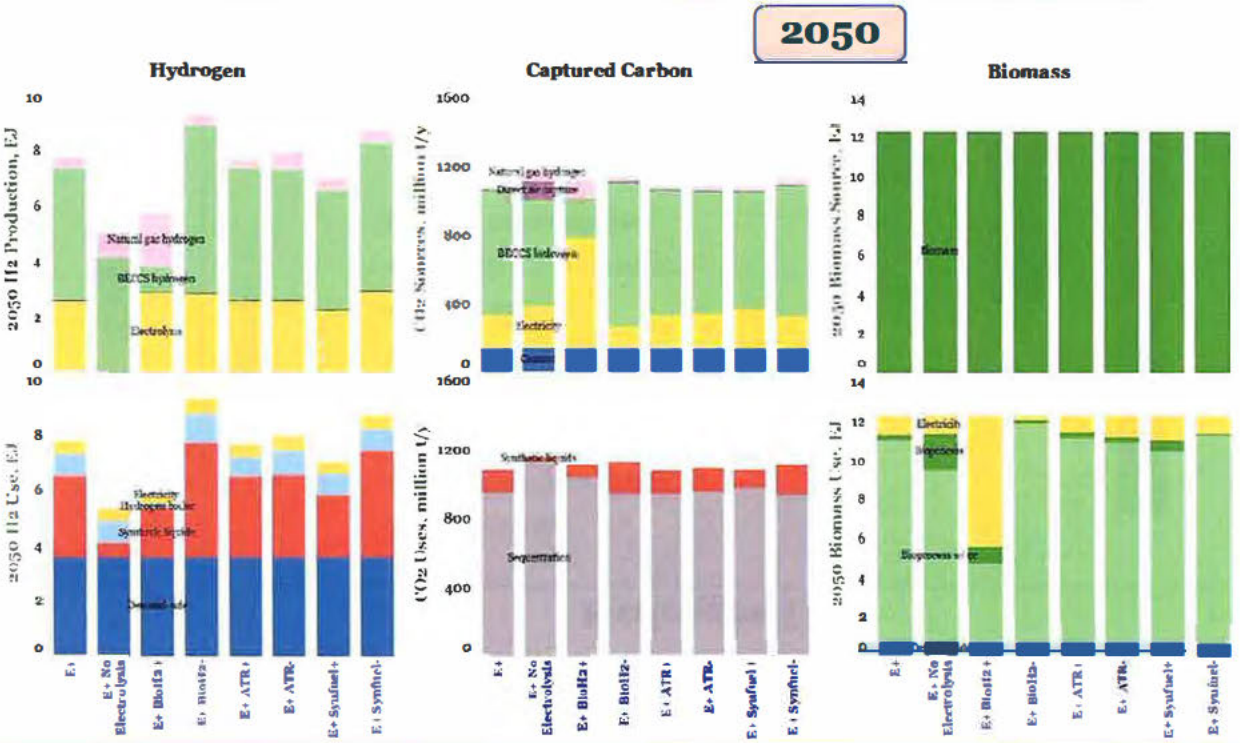
Demand side = H_2 used in transport and for production of chemicals, direct-reduced iron, and process heat in various industries.

Note: All fuel values reported in this slide pack are on HHV basis.

Model outputs are impacted by cost/availability assumed for H_2 production and related fuels-synthesis technologies.

Compared with E+:

- If electrolysis is disallowed, total H_2 produced is 35% lower, while H_2 from natural gas (ATR-CCS) doubles. Synthetic liquids production is much lower. Direct air capture is deployed to offset residual emissions from greater ATR and use of more petroleum fuels.
- Higher bio-H_2 drives biomass use from H_2 production to electricity generation with CO_2 capture. More gas is used for H_2 production, ands synthetic liquids output falls modestly.
- Results are relatively insensitive to different ATR costs.
- Higher FT synthesis cost reduces output of H_2 and synthetic liquids by ~25%. Lower FT synthesis cost increases H_2 from biomass and via electrolysis.
- NPV of total energy-supply system costs (2020-2050) are about the same for all cases shown.



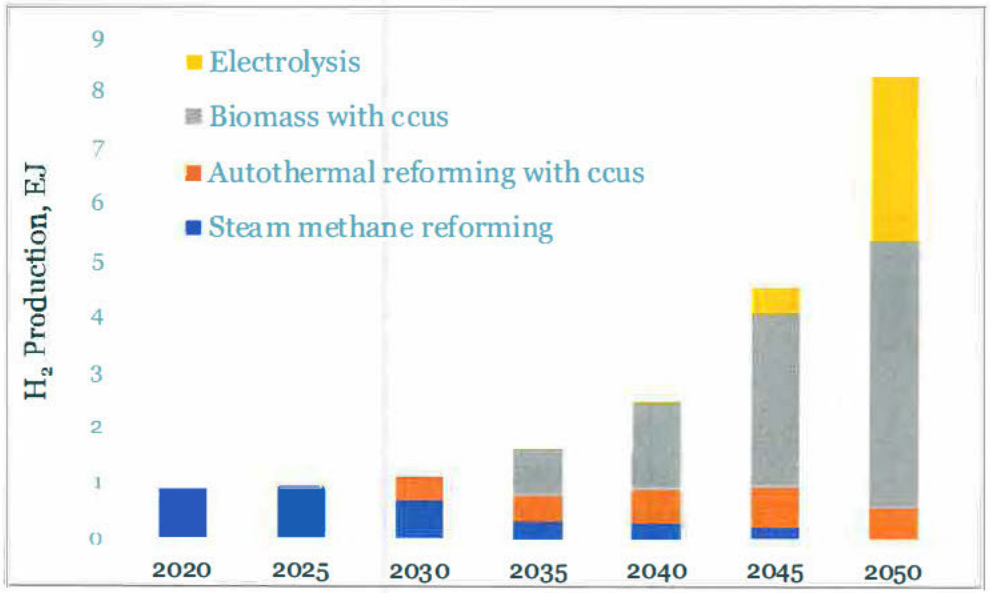
Input assumptions that vary between cases, installed capital cost in 2050 (2016$)

$/kW$_{H_2}$ (HHV)	E+	E+ No Electrolysis	E+ BioH2+	E+ BioH2-	E+ ATR+	E+ ATR-	E+ Synfuel+	E+ Synfuel-
BECCS-H_2	2700	2700	4050	2160	2700	2700	2700	2700
ATR-CCS (H_2 from nat. gas)	814	814	814	814	1221	651	814	814
FT (Fischer-Tropsch) synth.	1155	1155	1155	1155	1155	1155	1732	924
Electrolysis	420	not allowed	420	420	420	420	420	420

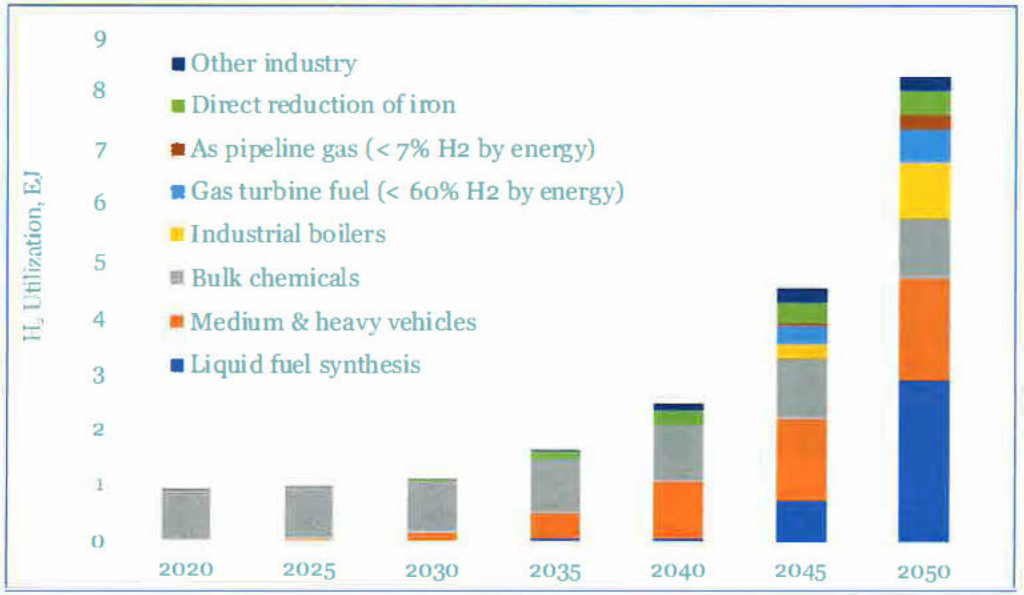
By 2050, H_2 production in E+ scenario reaches 8 EJ, or 61 billion scf/day (~6x today's level).

Majority of hydrogen users would be co-located with production, but distributed users would be served by regional pipeline networks or truck delivery.

Hydrogen Sources



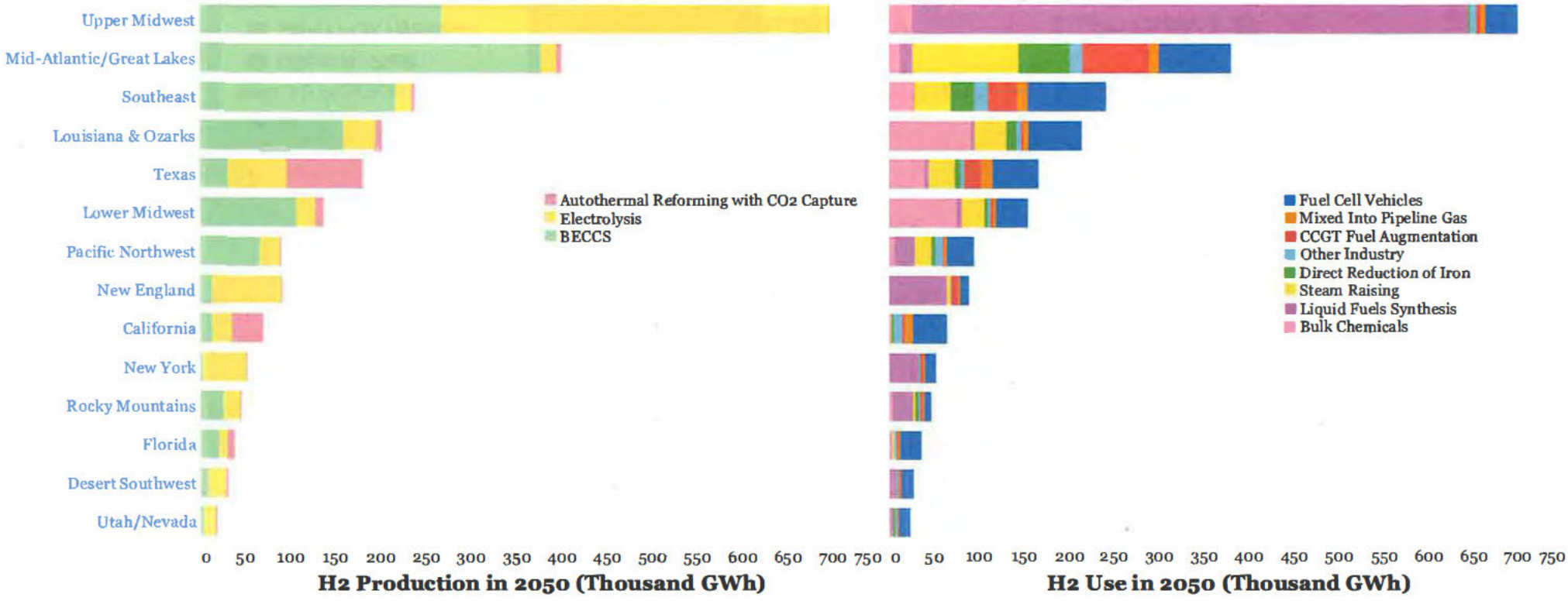
Hydrogen Uses



Note: All fuel values reported in this slide pack are on HHV basis.

Large H_2-using synfuels industry operating in 2050, primarily in Upper Midwest, but also New York/New England (E+ scenario)





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Note: All fuel values reported in this slide pack are on HHV basis.

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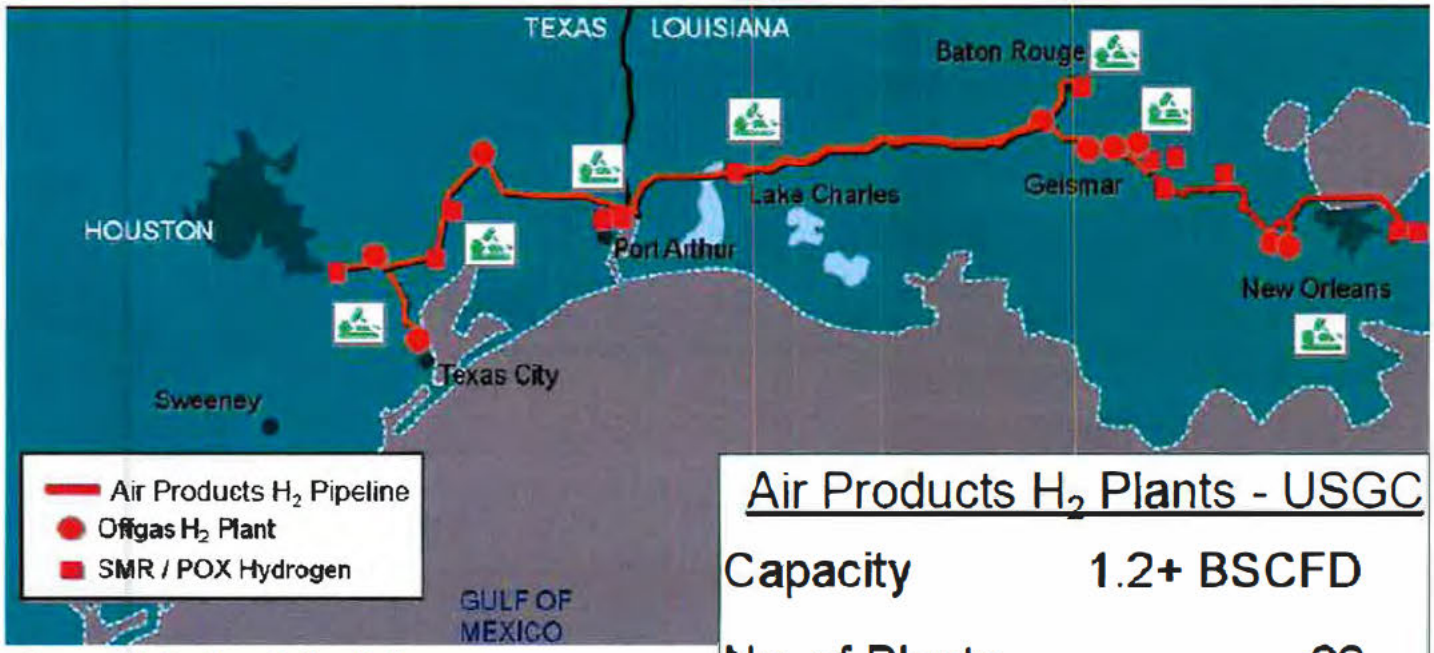
Carbon Mitigation Initiative

Industrial H_2-using clusters operate today in U.S. and elsewhere. Here, Air Products & Chemicals Gulf Coast H_2 infrastructure.

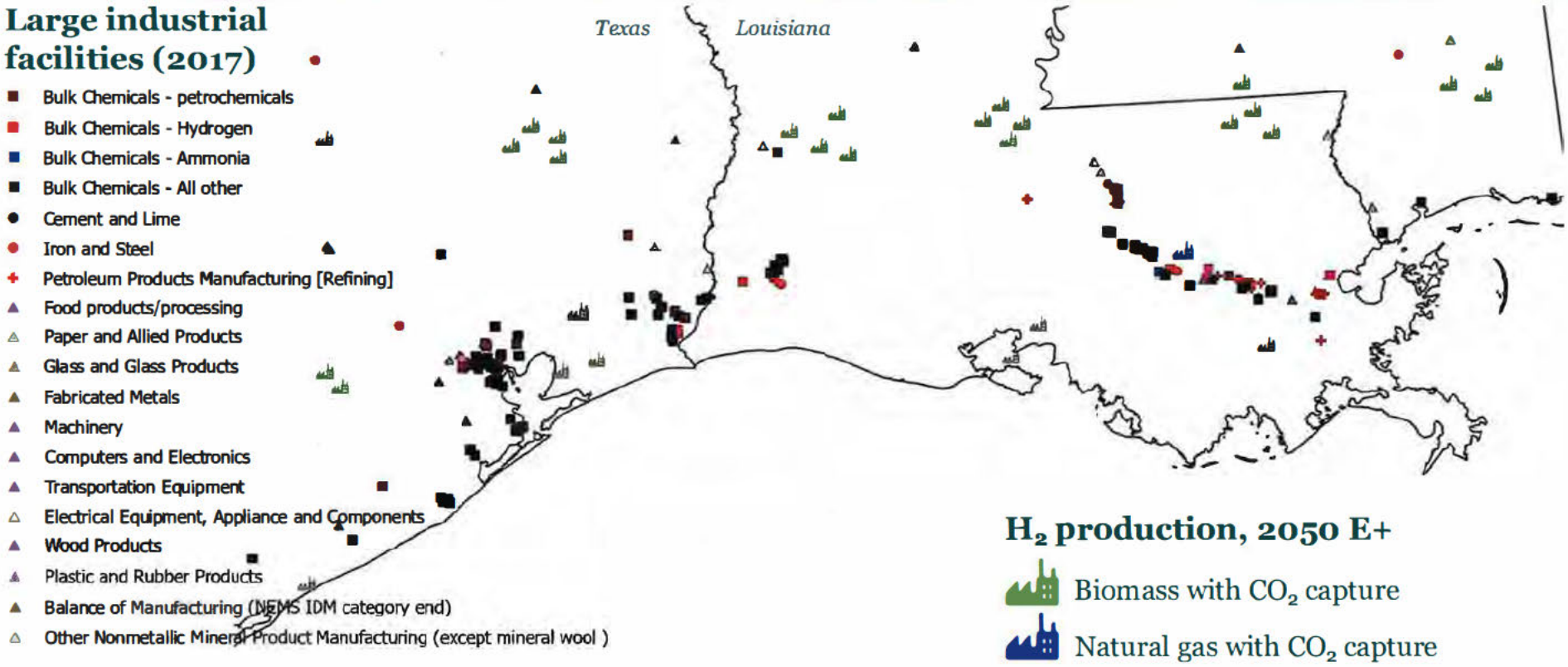
- A total of about 2,500 km of H_2 pipelines are in service in the US today
- The most significant H_2-using clusters today are on the Gulf Coast



Air Products H_2 Plants - USGC	
Capacity	1.2+ BSCFD
No. of Plants	22
Pipeline Length	~ 600 miles

Source: Air Products & Chemicals, 2012.

Notional view of H_2 production and use on the Gulf Coast, 2050



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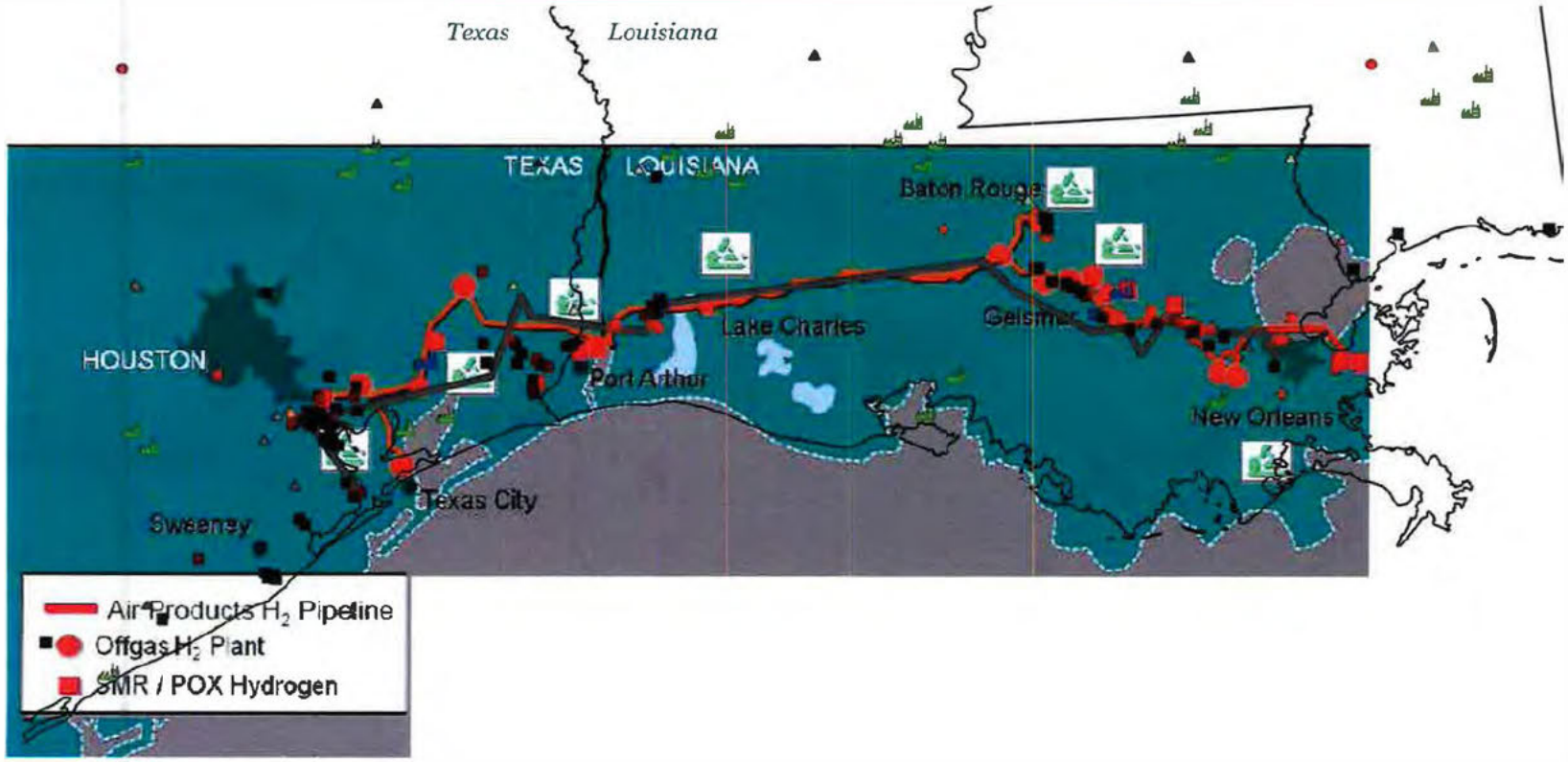
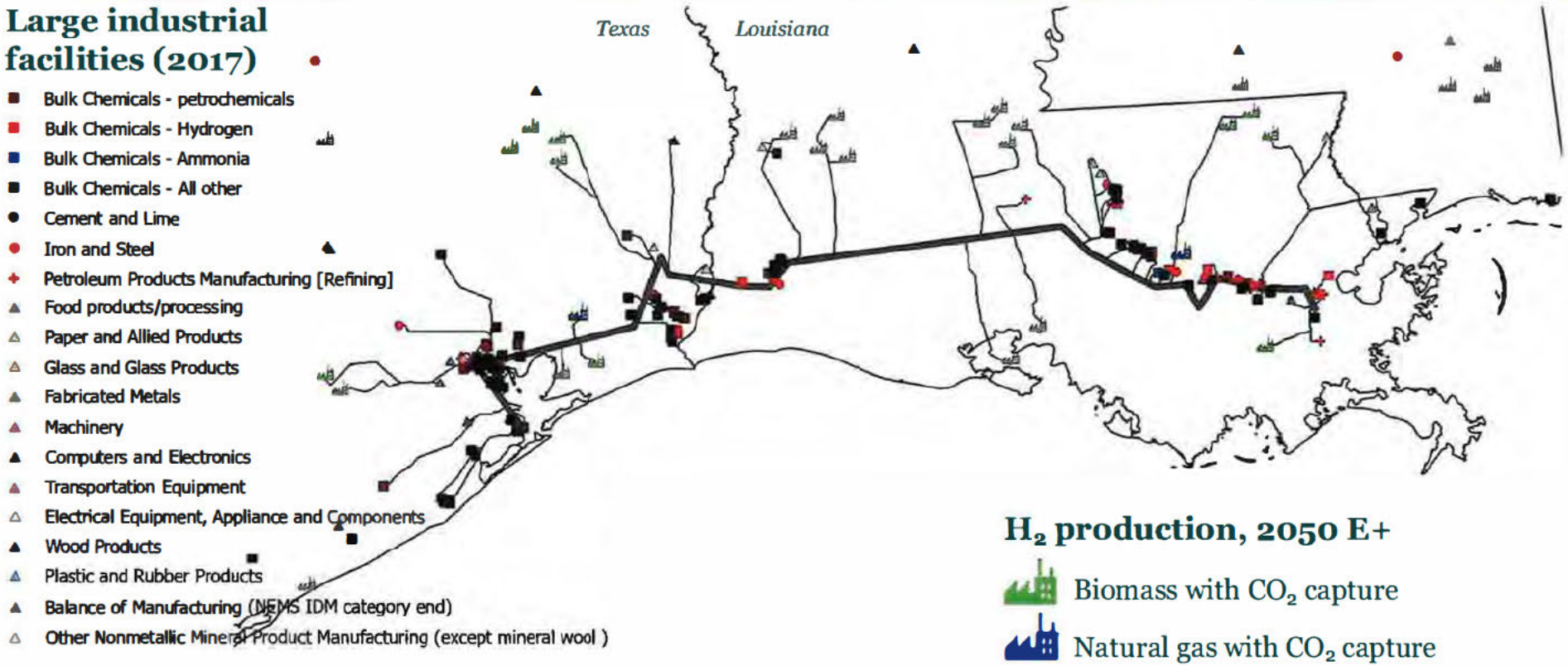
Notional view of H_2 production and use on the Gulf Coast, 2050



Notional view of H_2 production and use on the Gulf Coast, 2050





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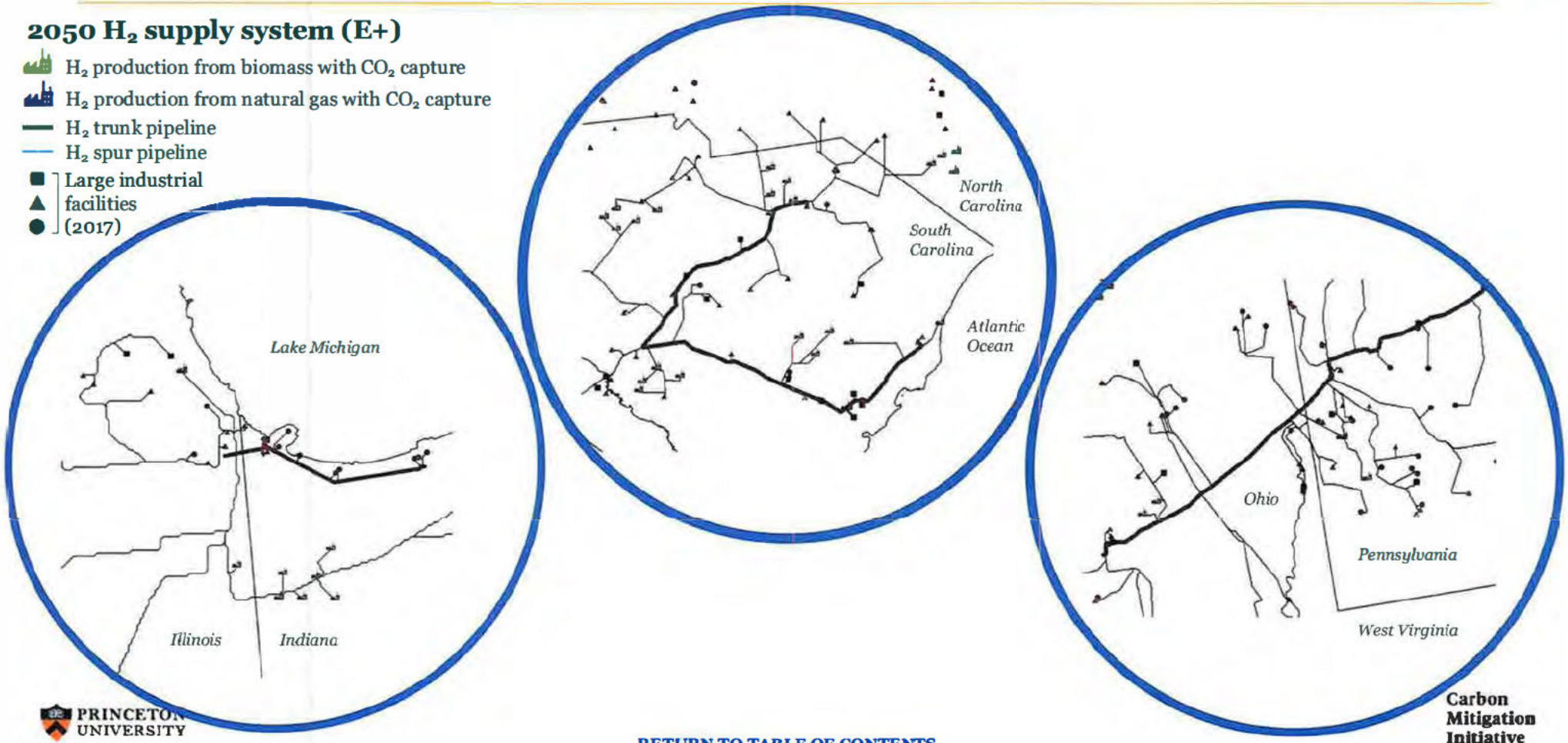
Notional view of other potential H_2 production and use clusters



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Carbon Mitigation Initiative

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Pillar 4: CO_2 capture, transport, usage, and geologic storage



Summary of this section

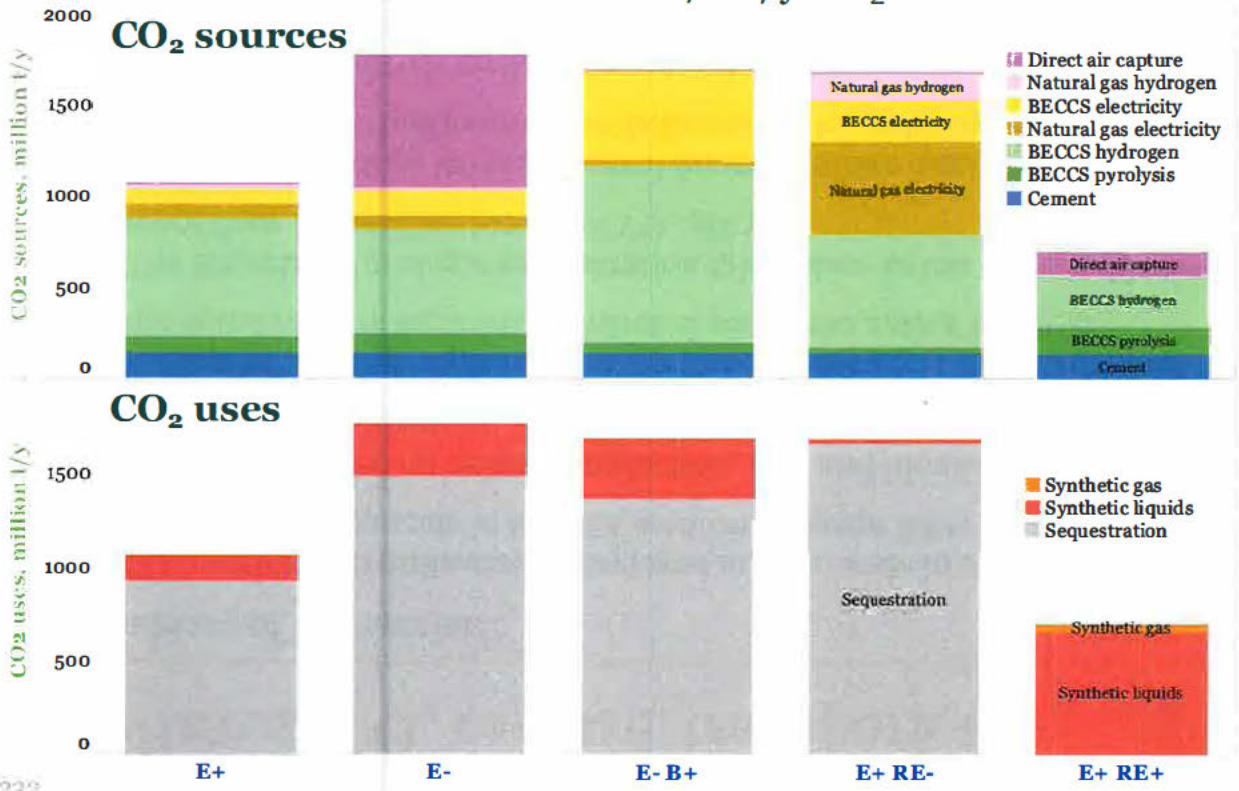
- CO_2 capture and utilization is deployed at large scale in all NZA scenarios. Capture, utilization, and storage (CCUS) is deployed at large scale in all NZA scenarios, except RE+.
- CCUS is deployed on cement production, gas- and biomass-fired power generation, natural gas reforming, biomass derived fuels production, and in some cases from direct atmospheric air capture.
- Geological sequestration rates range from almost 1 to 1.7 billion tonnes of CO_2 per annum, servicing more than a thousand capture facilities distributed across the nation by 2050.
- The majority of geologic sequestration takes place in the Texas gulf coast but other basins host sequestration of 10's to more than 100 million tonnes of CO_2 per year.
- An investment of 13 B$ is estimated for stakeholder engagement and characterization, appraisal and permitting across multiple storage basins and sites before 2035 to enable rapid expansion thereafter.
- The CCUS industry is enabled by around 110,000 km of new CO_2 pipeline infrastructure with an estimated capital cost of $170 to $230 billion.
- Estimated unit costs for CO_2 transport and storage average $17 to $23 per tonne stored depending on the ultimate scale of deployment.
- The scale of CO_2 transport and storage in these scenarios ranges from 1.3 to 2.4 times current US oil production on a volume equivalent basis.

CO_2 capture at multiple facility types and some CO_2 utilization in all pathways; significant CO_2 storage in all but one pathway



By 2050

- 0.7 to 1.8 Gt/y CO_2 captured.
- 0.9 to 1.7 Gt/y CO_2 sequestered.
- 0.1 to 0.7 Gt/y CO_2 converted to fuels.



CO_2 sources

Direct air capture

BECCS electricity (gasifier-Allam cycle)

Natural gas electricity (Allam cycle)

BECCS hydrogen (gasifier/water gas shift)

BECCS pyrolysis (hydrocatalytic)

Cement via 90% capture (post-combustion).

CO_2 uses

Synthetic liquids = synthesis of fuels from H_2 + CO_2.

Synthetic gas = methane synthesis from H_2 + CO_2.

Sequestration = geological storage

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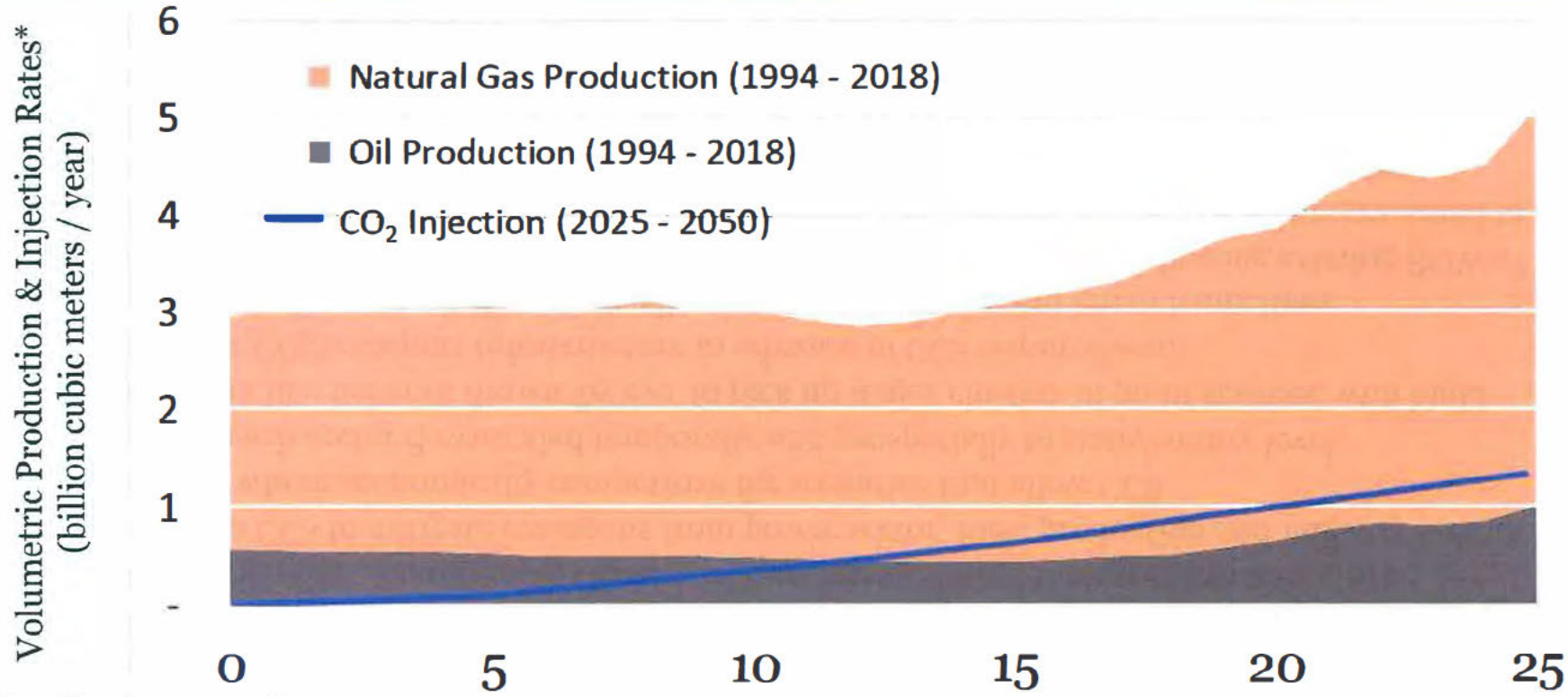
CO_2 injection rates grow from small today to 27% of 2018 oil & gas extraction rates in 2050 (at notional in situ reservoir conditions)



* At notional in situ reservoir conditions (2,000 m depth)

Oil & gas production data from BP Statistical review of Energy

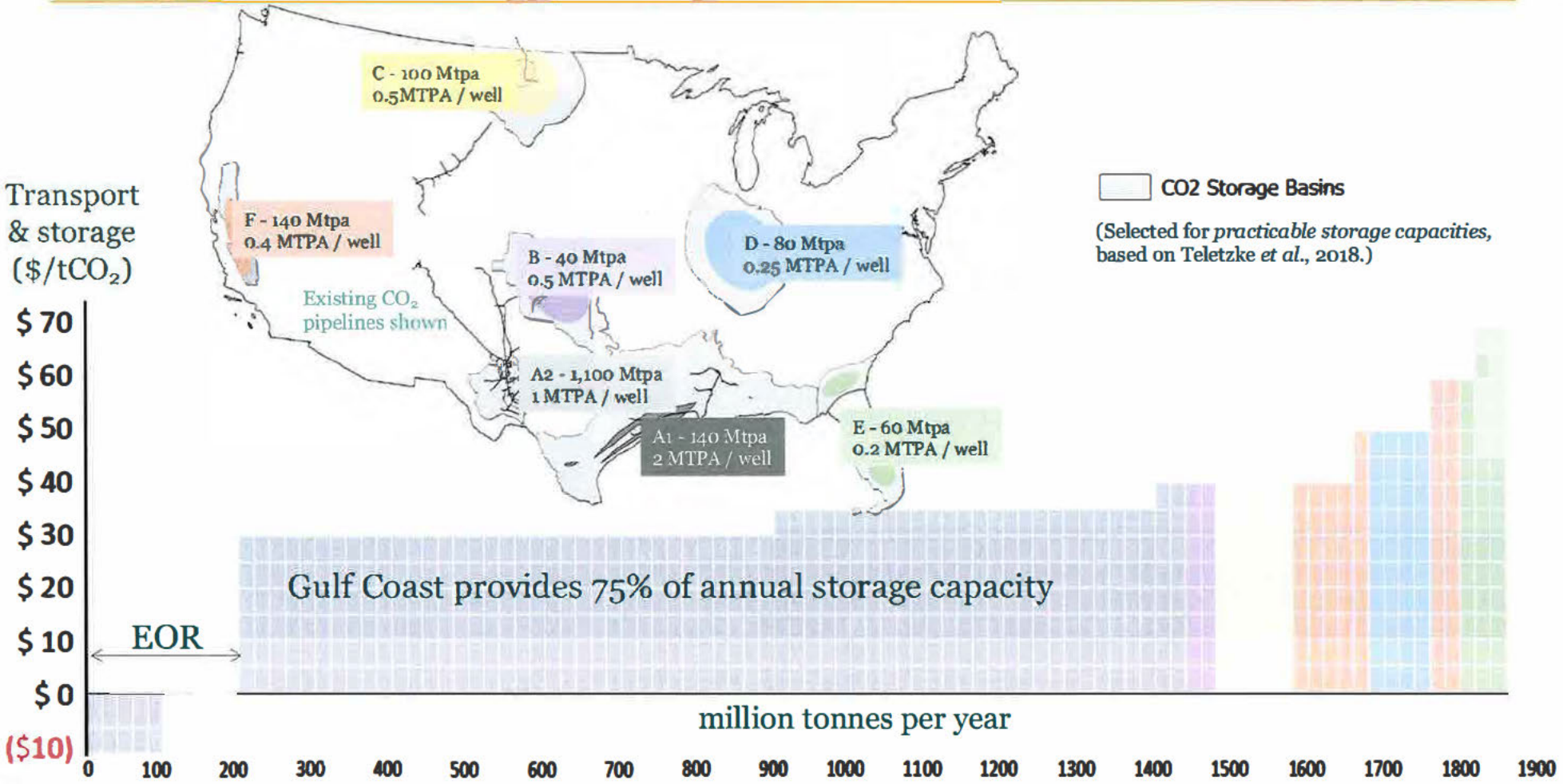
CO_2 transportation network combines state-of-art understanding of storage basins and geospatial downscaling of CO_2 point sources.



1. The most prospective CO_2 storage basins chosen based on practicable storage capacity (accessible, sustainable annual injection rates) estimates after Teletzke *et al.* (2018).
2. Notional supply-cost curve for CO_2 transport and storage established using expert judgement and industry consultation (BP, ExxonMobil, Occidental), assuming shared transport infrastructure.
3. Rio Model chooses CCS to mitigate emissions from power sector, fuels production and industry sectors across 14 regions, where economically competitive for scenarios that allow CCS.
4. Point sources for each sector downscaled temporally and geospatially to state/county level.
5. Notional CO_2 trunk line network drawn 'by eye' to pick up major clusters of point sources, with build program to deliver CO_2 transport infrastructure in advance of CCS requirement.
6. Point source downscaling repeated to locate all point sources within 200 km of trunk lines.
7. Spur lines connect point sources to trunk lines using minimum distance and following existing ROWs.*
8. Trunk lines sized and costed using FE/NETL CO_2 Transport Cost Model, and build-out programmed to meet expansion of CO_2 point sources for all trunk line catchment areas. Spur lines costed using a simple *Cost = f(tpa, km)* equation derived from the FE/NETL CO_2 Transport Cost Model.
9. Levelized cost of CO_2 transport established based on capital cost estimates, build schedules, and CO_2 expansion using discounted cash flow model.
10. Cost-supply curves calculated for different potential capacity charge arrangements.

* Existing ROWs include natural gas, NH_3 and CO_2 pipelines, railways, interstate highways, and > 220kV electricity transmission lines, as mapped in Edwards and Celia, "Infrastructure to enable deployment of carbon capture, utilization, and storage in the United States," *PNAS*, 115(38): E8815-E8824, 2018.

Notional CO_2 storage capacity appraised, permitted and developed in 2050 is 1.8 billion t/y, mostly in Gulf Coast



$13 Billion investment in stakeholder engagement, characterization, appraisal and permitting activities before 2035 to enable rapid expansion

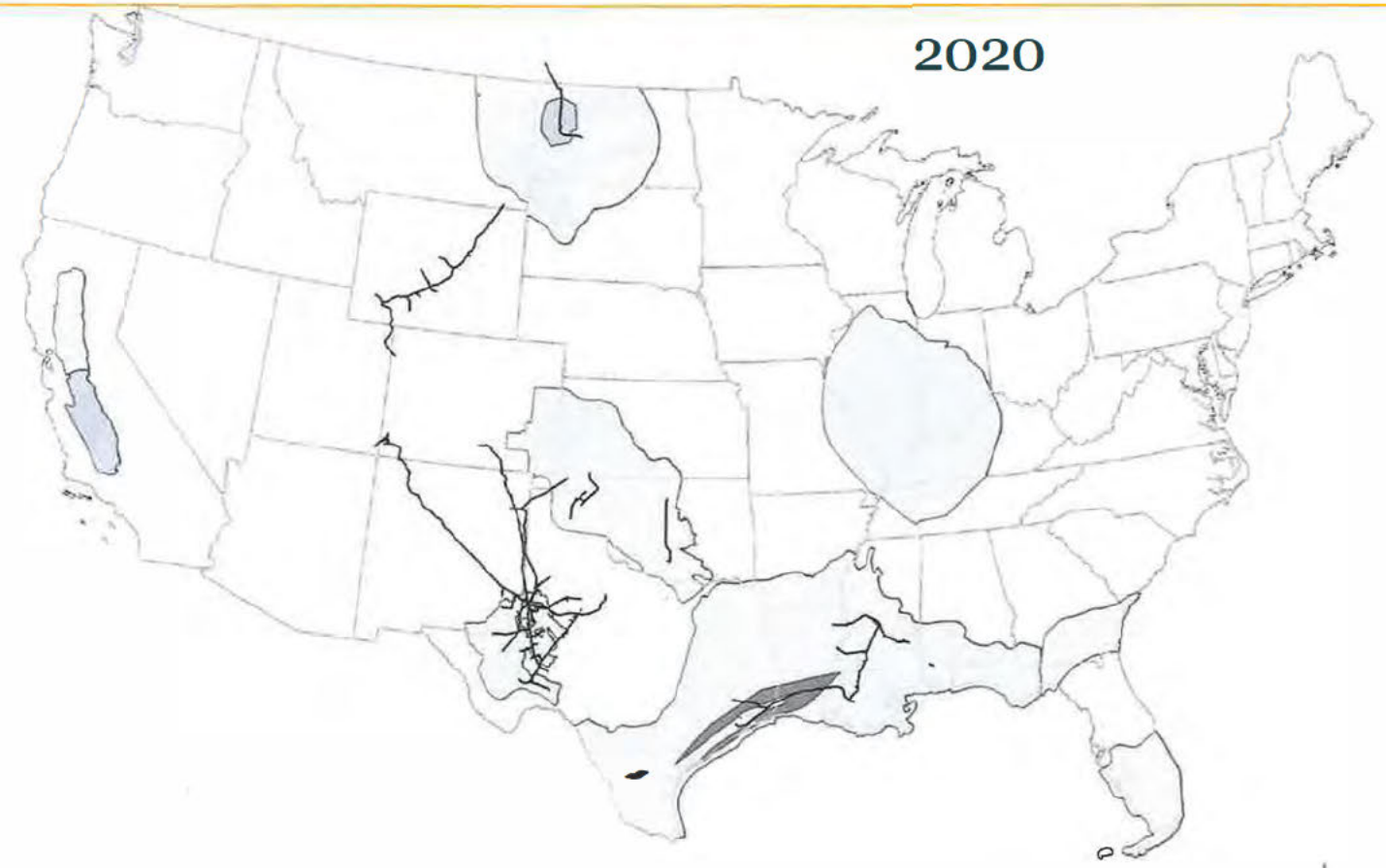


Item	2021-25 Investment (Million $)	2026-30 Investment (Million $)	2031-35 Investment (Million $)	Notional Capacity Appraised (MMtpa)
CO_2 Basin-wide Assessments*	1,500	1,500		
CO_2 Site Appraisal and Permitting**				
Area A1	0	700	400	110
Area A2	0	4,000	2,700	670
Area B	0	100	100	20
Area C	0	200	300	50
Area D	0	200	200	40
Area E	0	100	200	30
Area F	0	300	500	80
Totals	**1,500**	**7,100**	**4,400**	**1,000**

* Estimated to be $500 million per basin (basins A – F identified in prior slide).
** See previous slide for basin labels.

Existing CO_2 pipeline network

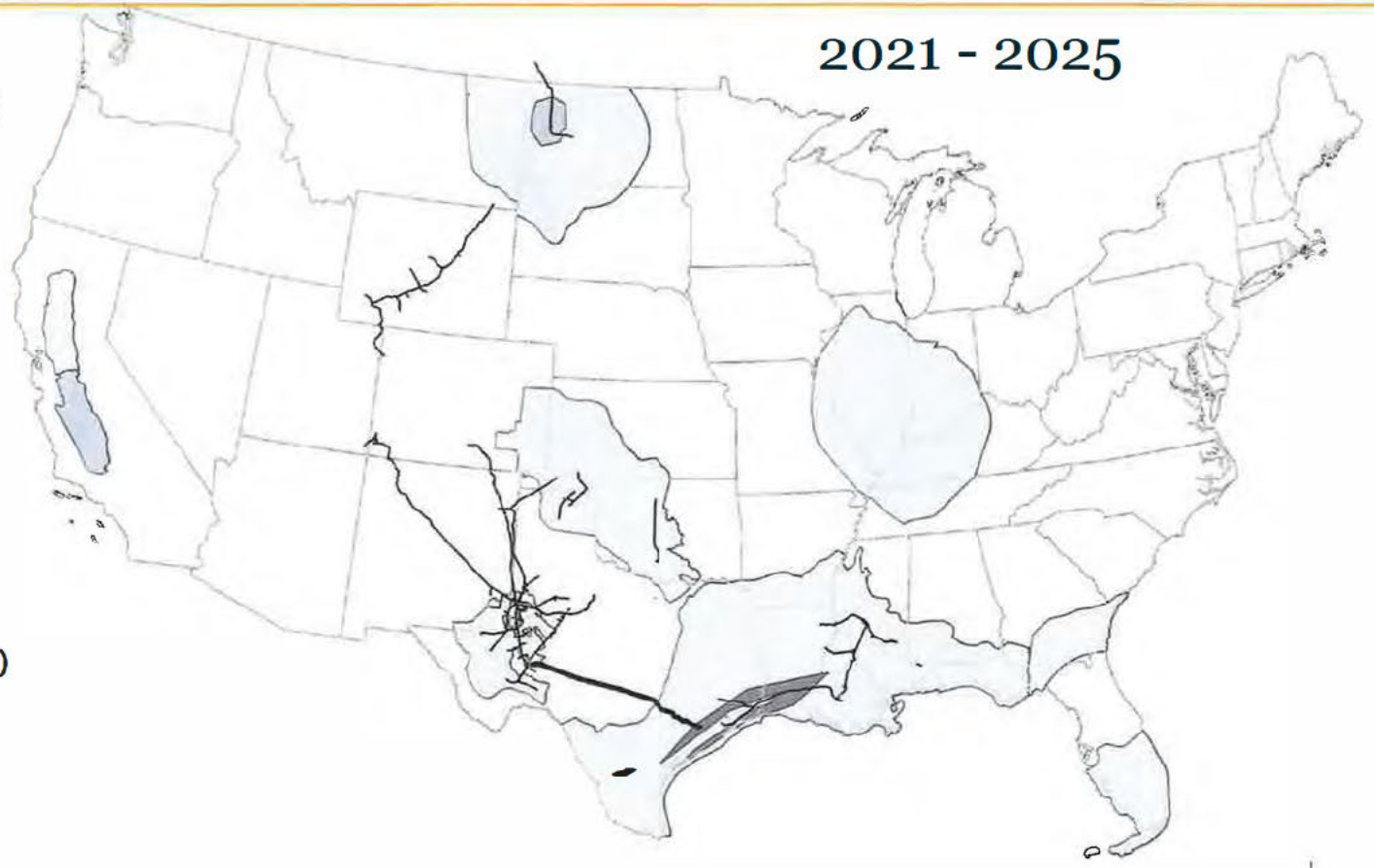
- ~ 80 million tCO_2/yr transported
- ~ 8,500 km of pipelines
- Servicing enhanced oil recovery operations
- Majority in Permian Basin (West Texas and southeast New Mexico)



Trunk line construction begins before 2025 with connection between Permian Basin and Gulf Coast

E+ scenario

no CO_2 flow in this period
700 km pipelines
Capital in-service: $70B



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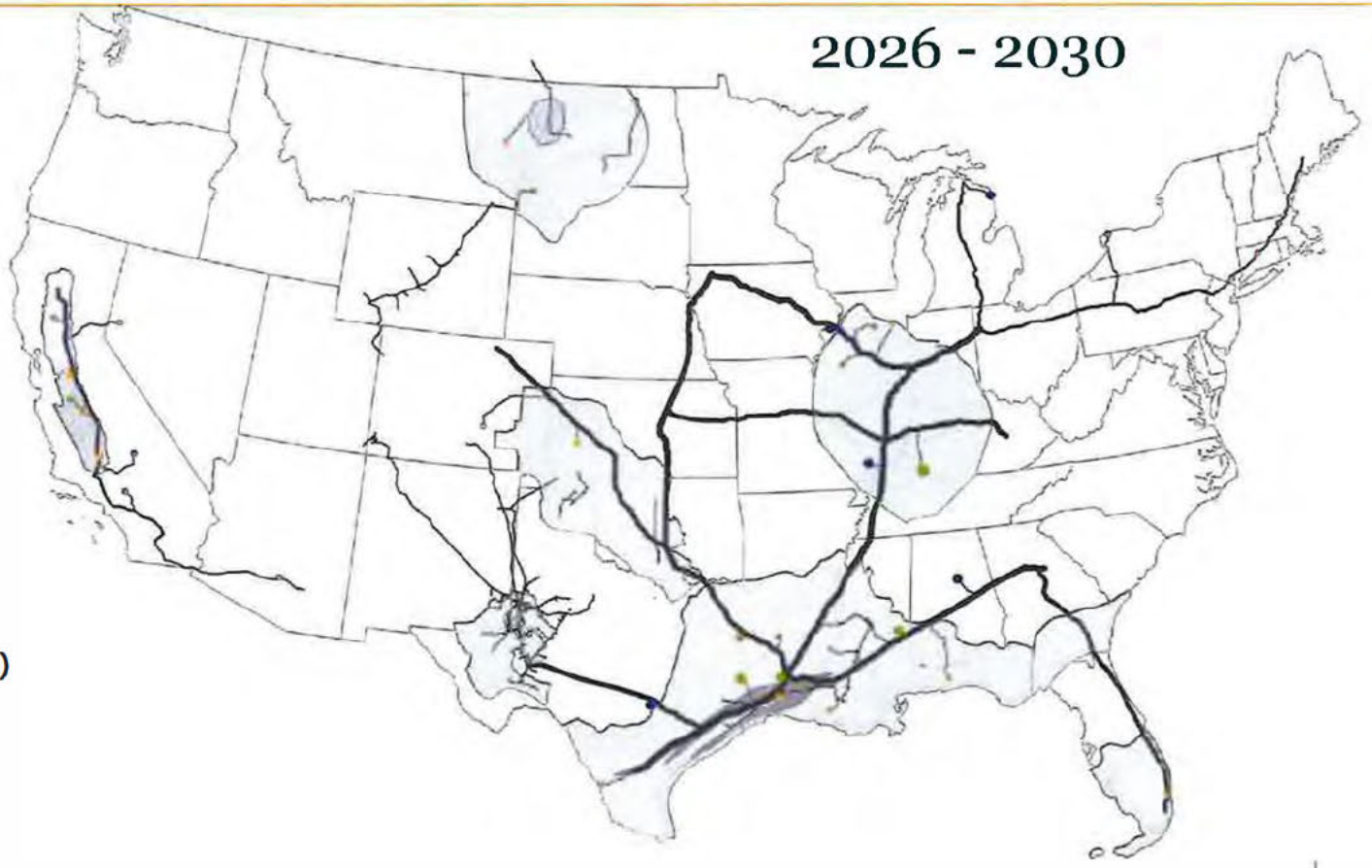
Carbon Mitigation Initiative

Trunk line build out continues and initial CO_2 capture plants come online, with spur lines connecting to trunk network

E+ scenario

65 million tCO_2/y
19,000 km pipelines
Capital in-service: $70B



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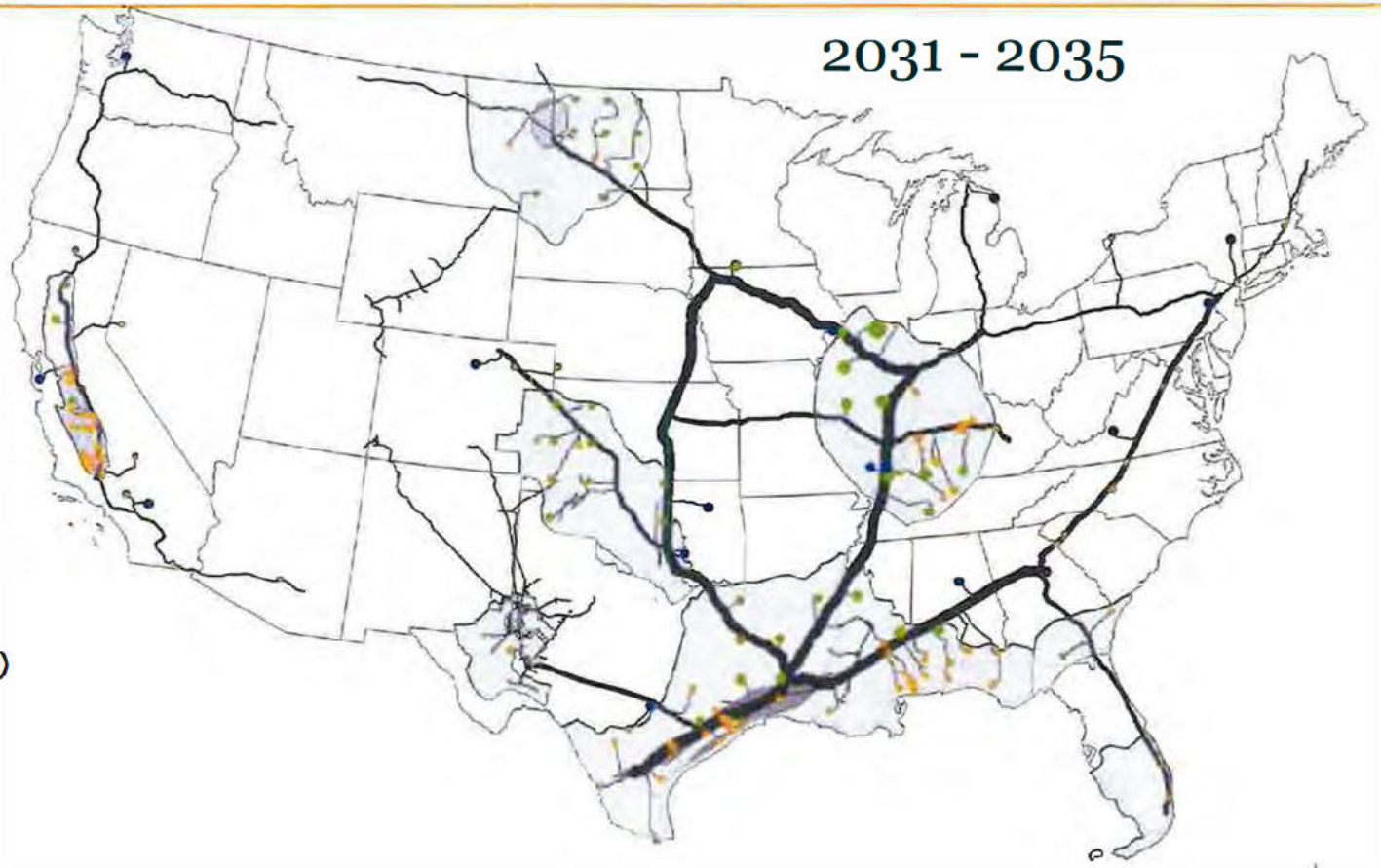
Carbon Mitigation Initiative

Trunk network routes complete; some sections add parallel lines as more capture projects are built and connect

E+ scenario

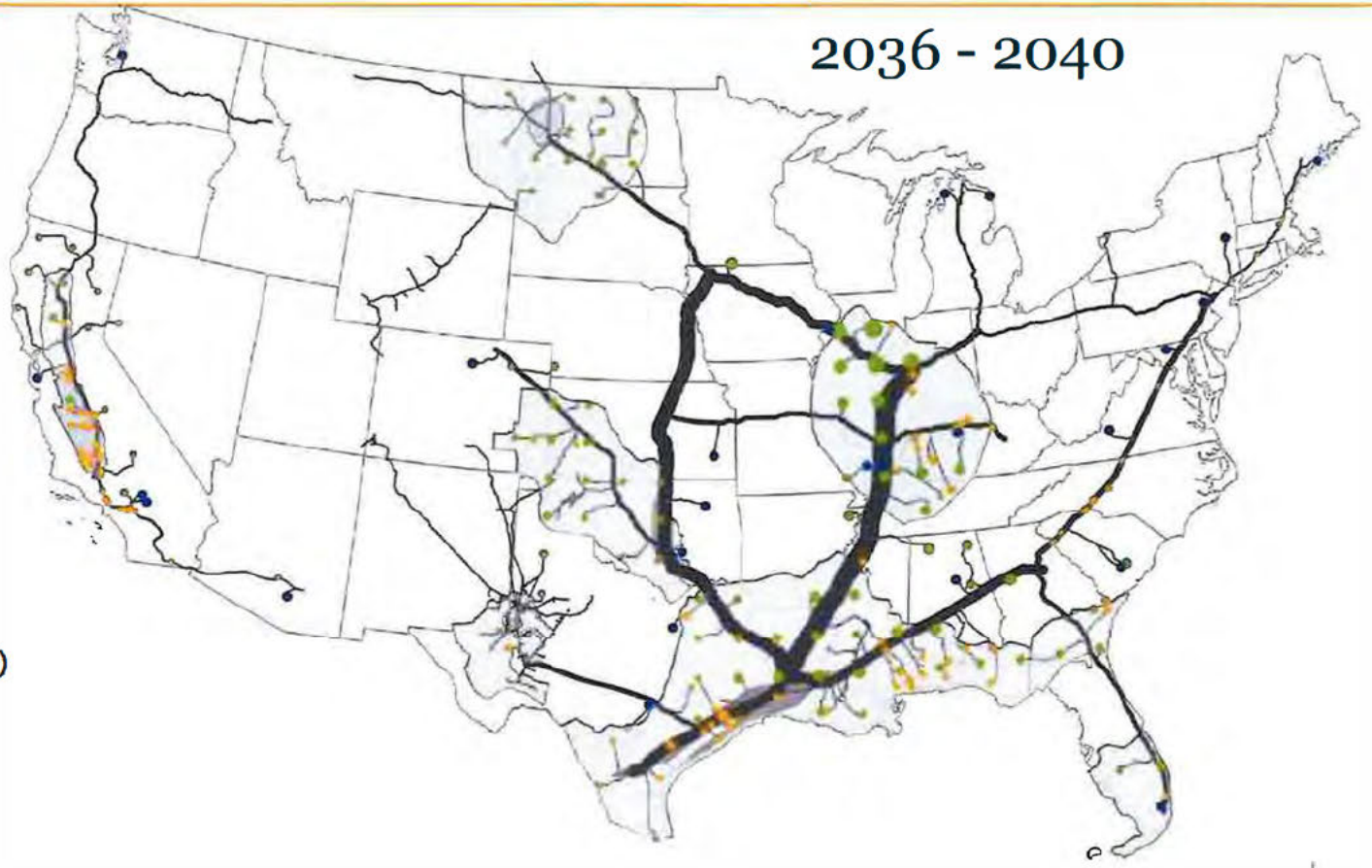
246 million tCO_2/y
41,000 km pipelines
Capital in service: $115B



More individual trunk line duplications as number of capture projects continues to grow

E+ scenario

435 million tCO_2/y
51,000 km pipelines
Capital in service: $125B



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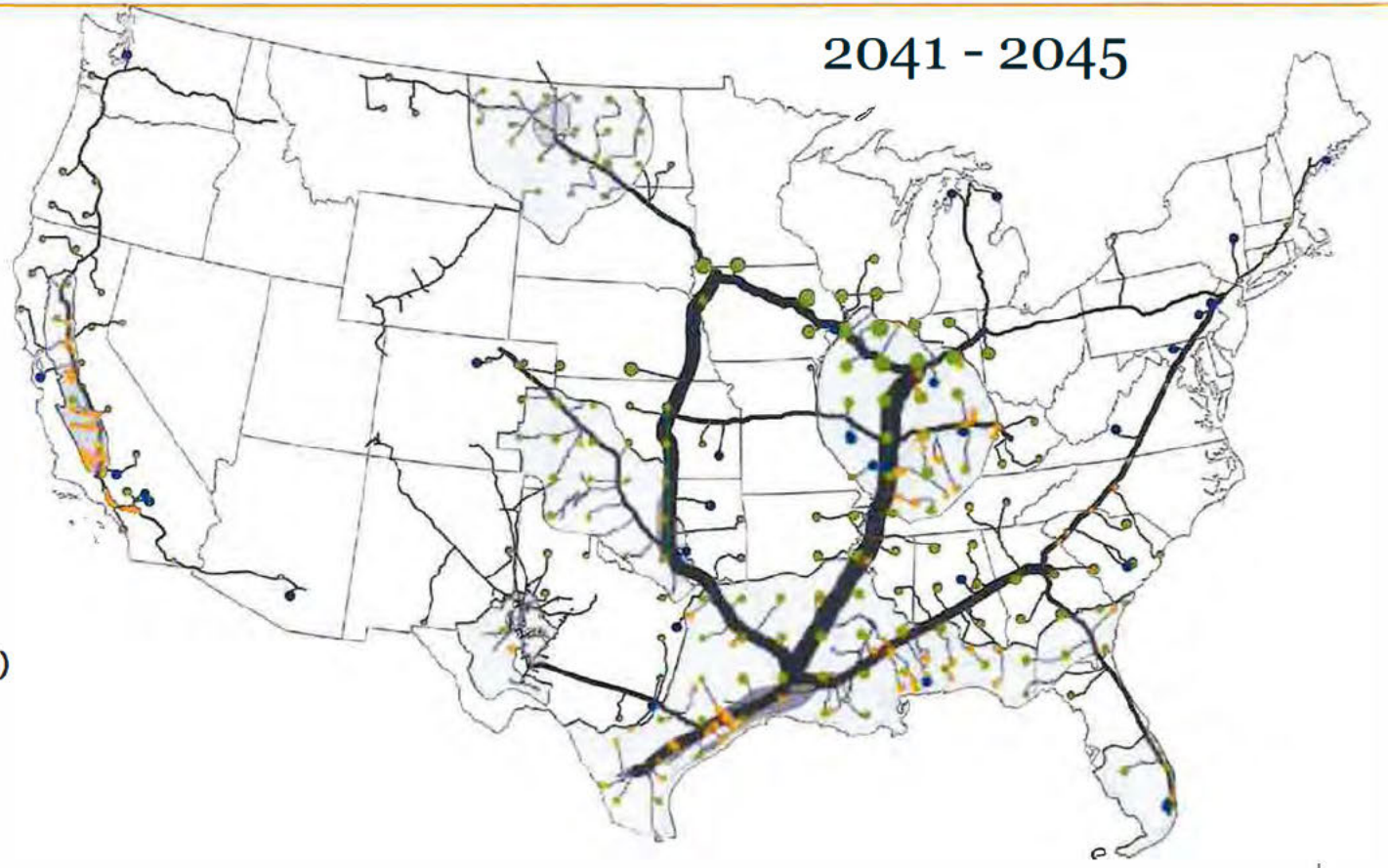
Carbon Mitigation Initiative

CO_2 capture plants connected to trunk lines grow rapidly

E+ scenario

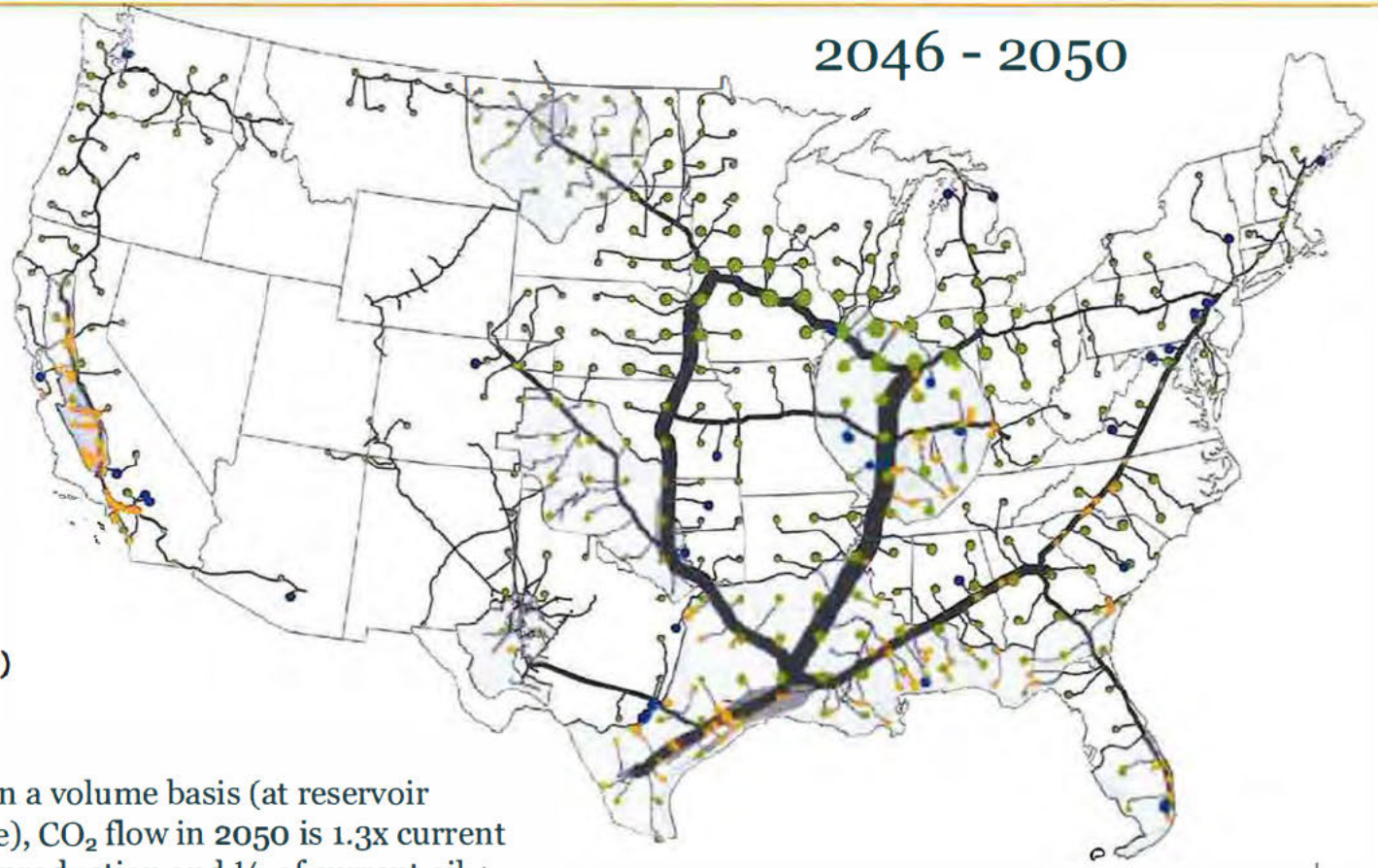
687 million tCO_2/y
70,000 km pipelines
Capital in service: $135B



2050 totals: 21,000 km trunk lines + 85,000 km spur lines (equivalent to ~22% of US natural gas transmission pipeline total)

E+ scenario

929 million tCO_2/y
106,000 km pipelines
Capital in service: $170B



Note: On a volume basis (at reservoir pressure), CO_2 flow in 2050 is 1.3x current U.S. oil production and ¼ of current oil + gas production.

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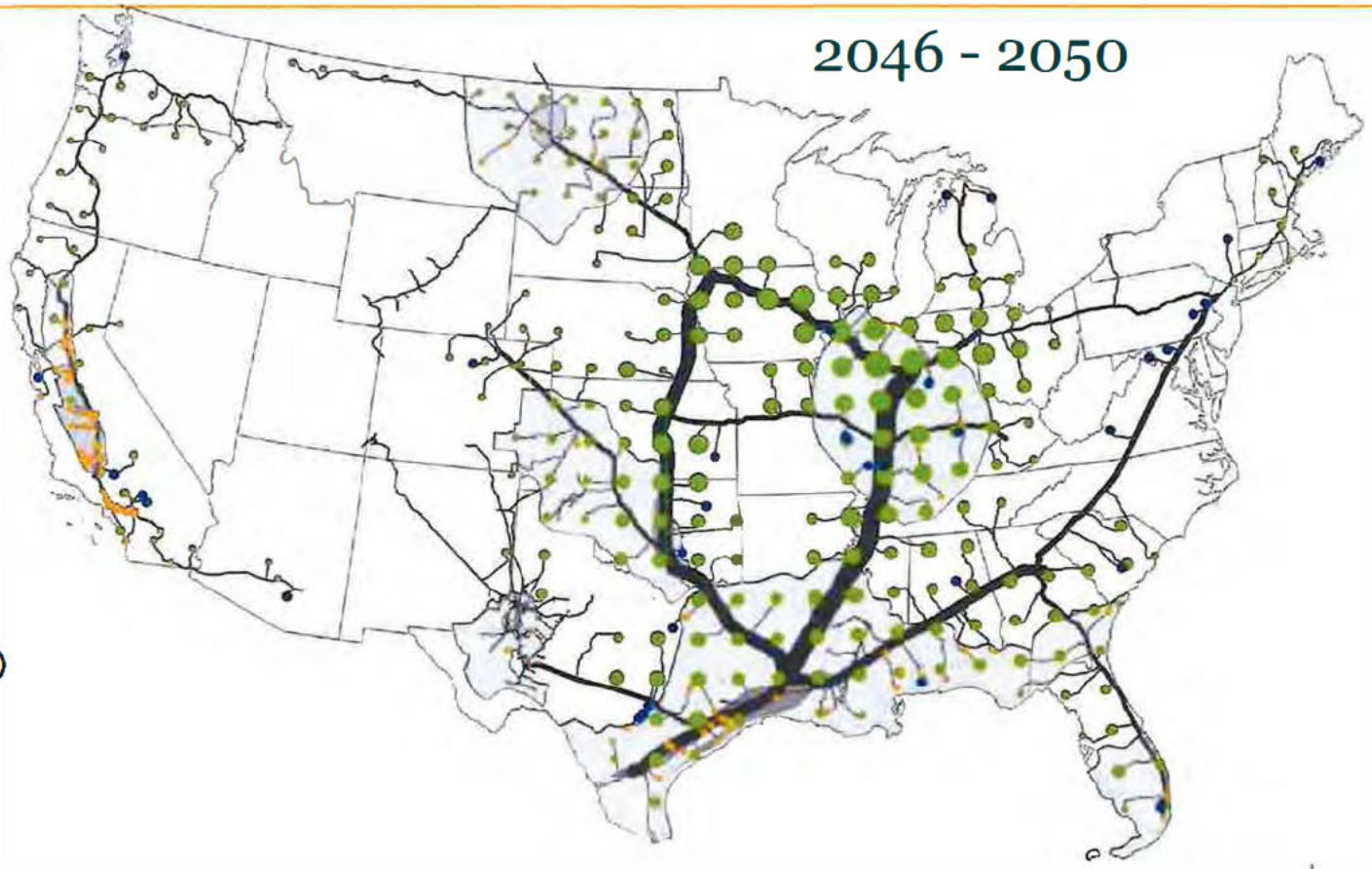
Carbon Mitigation Initiative

E- B+ utilizes the same trunk network, but with some additional parallel pipes in some corridors

E- B+ scenario

1,361 million tCO_2/y
111,000 km pipelines
Capital in service: $220B



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Capital for national CO_2 collection and transport network is $170 to $230 billion, or ~ $11 to $16/t$CO_2$ when amortized across all users



Costs (2020$)*	E+	E- B+
Trunk lines		
Total length, km	21,100	25,400
Total installed capital cost, billion 2020$	101	135
National network-access charge, $/t$CO_2$ delivered	11.3	7.6
Center-East network-access charge, $/t$CO_2$ delivered	11.3	7.4
West network-access charge, $/t$CO_2$ delivered	11.6	10.4
Spur lines		
Total length, km	85,800	85,700
Total installed capital cost, billion 2020$	69	88
National network-access charge, $/t$CO_2$ delivered	4.6	3.0
Total trunk + spur lines		
National network-access charge, $/t$CO_2$ delivered	15.9	10.6

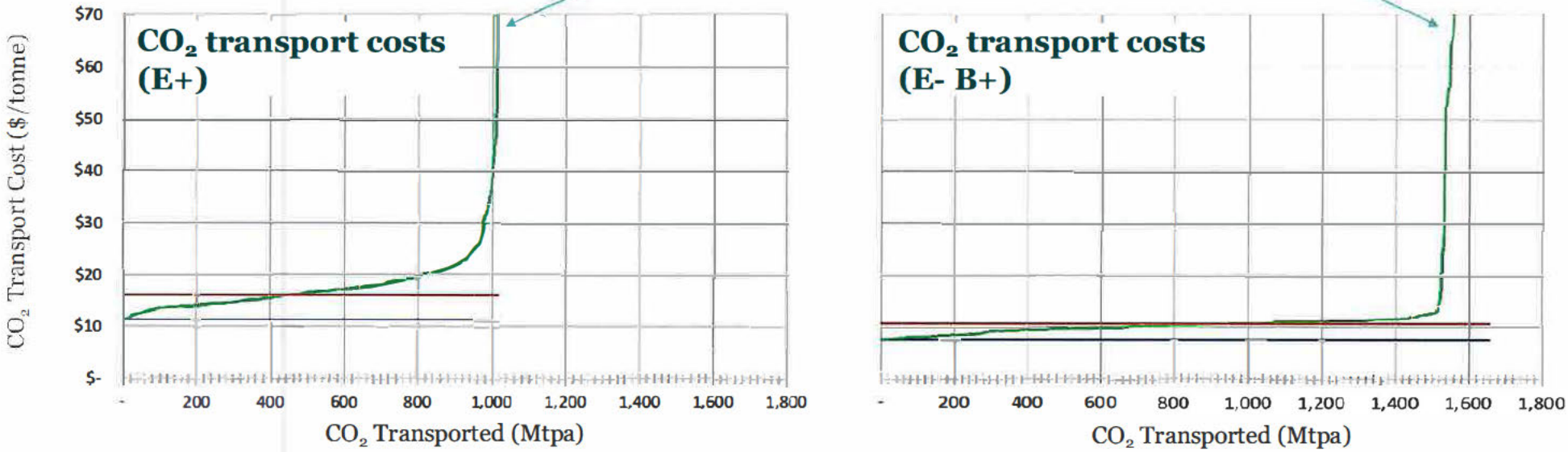
Higher charge for West than for Center-East trunk network

* Costs, including pipelines and compressors, were estimated using the DOE/NETL CO_2 Transport Cost Model (version 2b),.

Amortizing investments across all users avoids prohibitively high costs of small-capacity point sources financing their own spur lines.



Rapidly rising transport costs for smaller point sources with longer spur lines

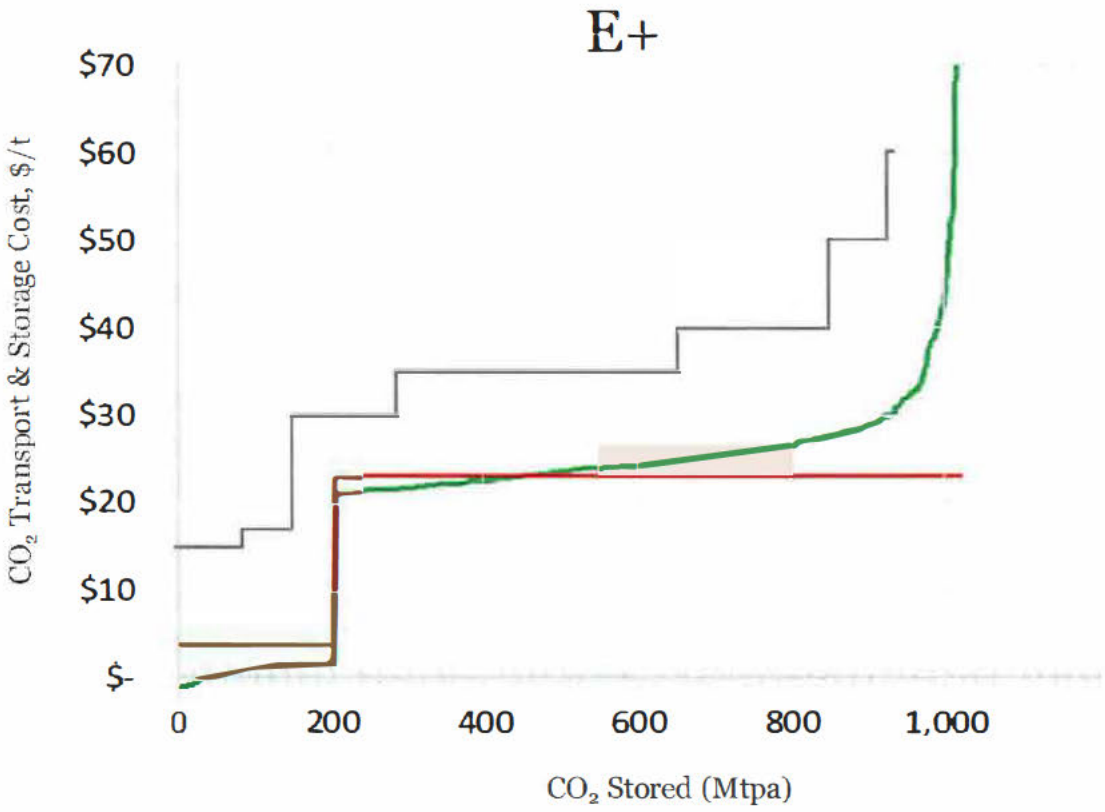


Trunk + spur line network-access charge. (All point sources charged equally, regardless of scale, location, or on-stream date.)

Trunk line network-access charge. (All point sources charged equally, regardless of scale, location, or on-stream date.)

Cost-supply curve assuming trunk line network-access charge + spur line investment by individual point sources.

Storage adds $7/tCO$_2$ (DOE low-end estimate) and EOR provides credit of $19/tCO$_2$ (for $50/bbl oil*).



CO_2 transport and storage costs calculated from the downscaling analysis are somewhat lower than the costs assumed in the original modeling of E+ pathway.

- Transport and storage cost assumed for **2050** in original modelling of E+ pathway
- Calculated trunk + spur line network-access charge. (All point sources charged equally, regardless of scale, location, or on-stream date.)
- Calculated assuming trunk line national network-access charge + spur line investment by individual point sources.

* Rubin, et al. (2015) wrote that "conventional wisdom suggests that the price that EOR projects can afford to pay for CO_2 (in $/1000 standard ft^3) is 2% of the oil price in $/bbl."

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Carbon Mitigation Initiative

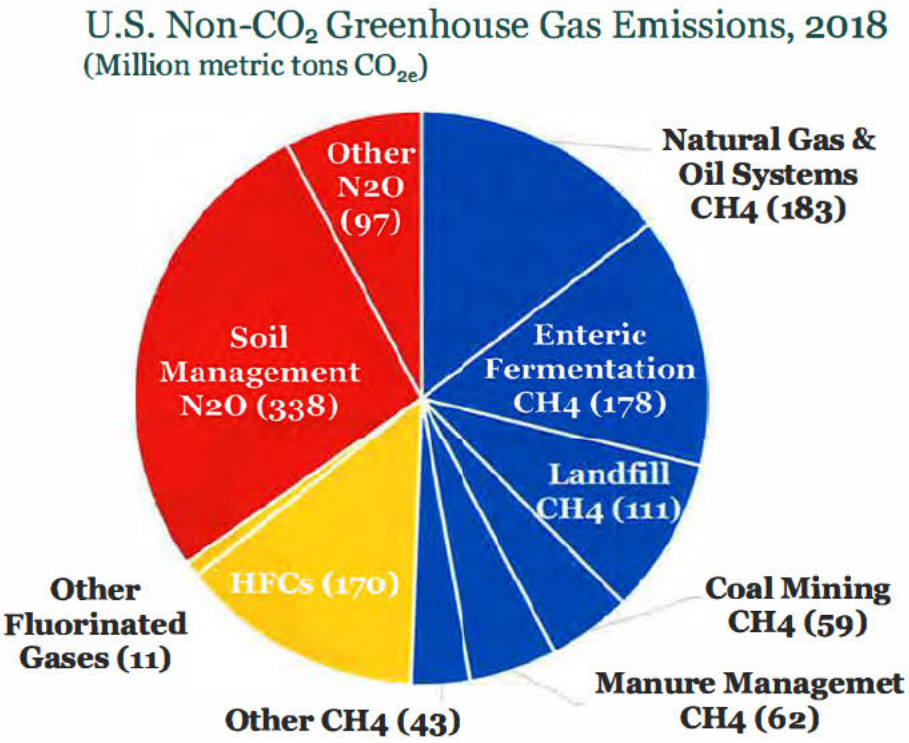
Pillar 5: Reduced non-CO_2 emissions



Summary of this section

- In a net-zero future, non-CO_2 greenhouse gas emissions each year must be compensated by removal of an equivalent amount of CO_2 from the atmosphere. In the modeling here, negative emissions can be achieved by permanent storage underground (or in long-lived plastics or similar products) of CO_2 derived from biomass or directly captured from the air, or (as discussed later below) by uptake in soils and trees.
- Sources of methane and nitrous oxides, which are the majority of non-CO_2 emissions today, are widely dispersed, making mitigation more challenging, and non-CO_2 emissions are projected to grow in the future under business-as-usual.
- The Net-Zero America study team did not conduct original analysis assessing mitigation options, but assumed as an input to the modeling a level of mitigation from 2020 to 2050 consistent with recent analysis from the U.S. Environmental Protection Agency (EPA).
- We also note that EPA's mitigation estimates assume future levels of oil and gas use that are closer to those of a "business-as-usual" future than a net-zero emissions future. In the latter, fossil fuel use is at least 70% to 80% lower today by 2050. The EPA projections assume some mitigation of non-CO_2 emissions associated with producing and transporting fossil fuels. Under a net-zero scenario, these emissions would be significantly lower due to the reduced fossil fuel use.

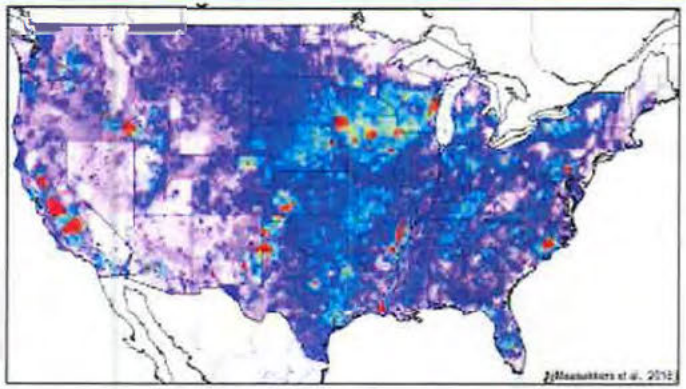
Non-CO_2 emissions today are 1.25 $GtCO_{2e}$/year



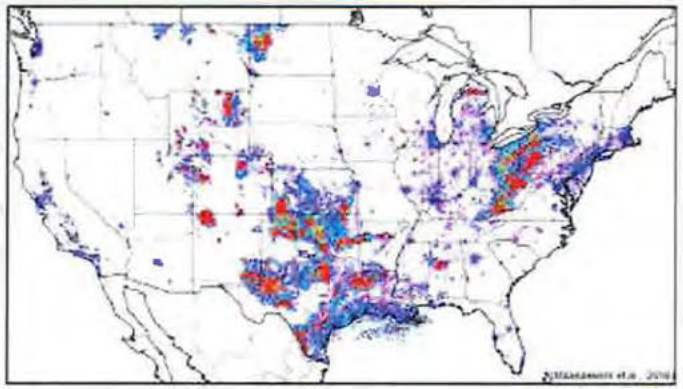
Source: EPA, *2020 GHG Inventory*

Methane emissions follow energy and agricultural production patterns and population densities

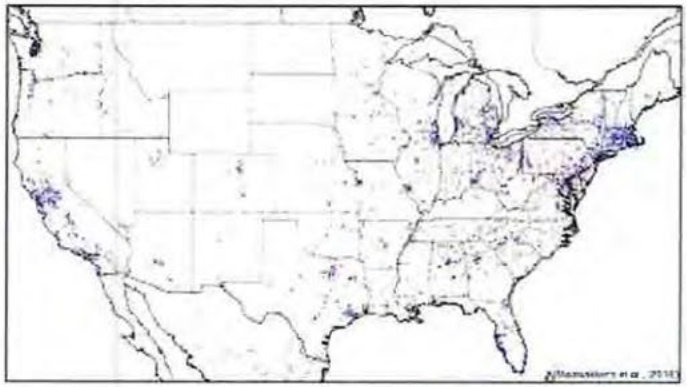
Agricultural emissions are dominated by livestock and dairy production



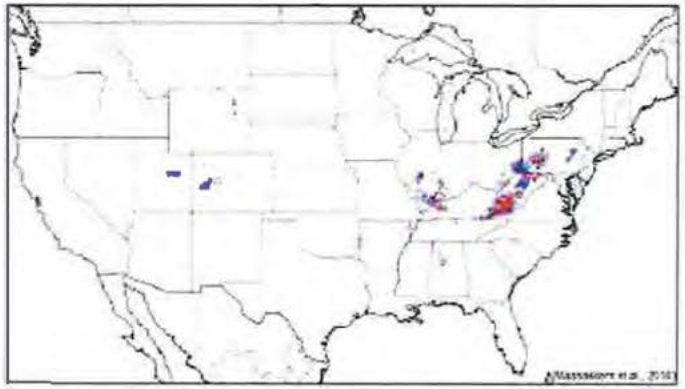
Oil and gas upstream emissions align with production & processing; downstream with pop.



Waste emissions are aligned with population density



Coal upstream emissions are dominated by Appalachian subsurface mining.



Source: EPA



2012 emissions (tCH_4/km^2)
(All emissions in the National GHG Inventory)

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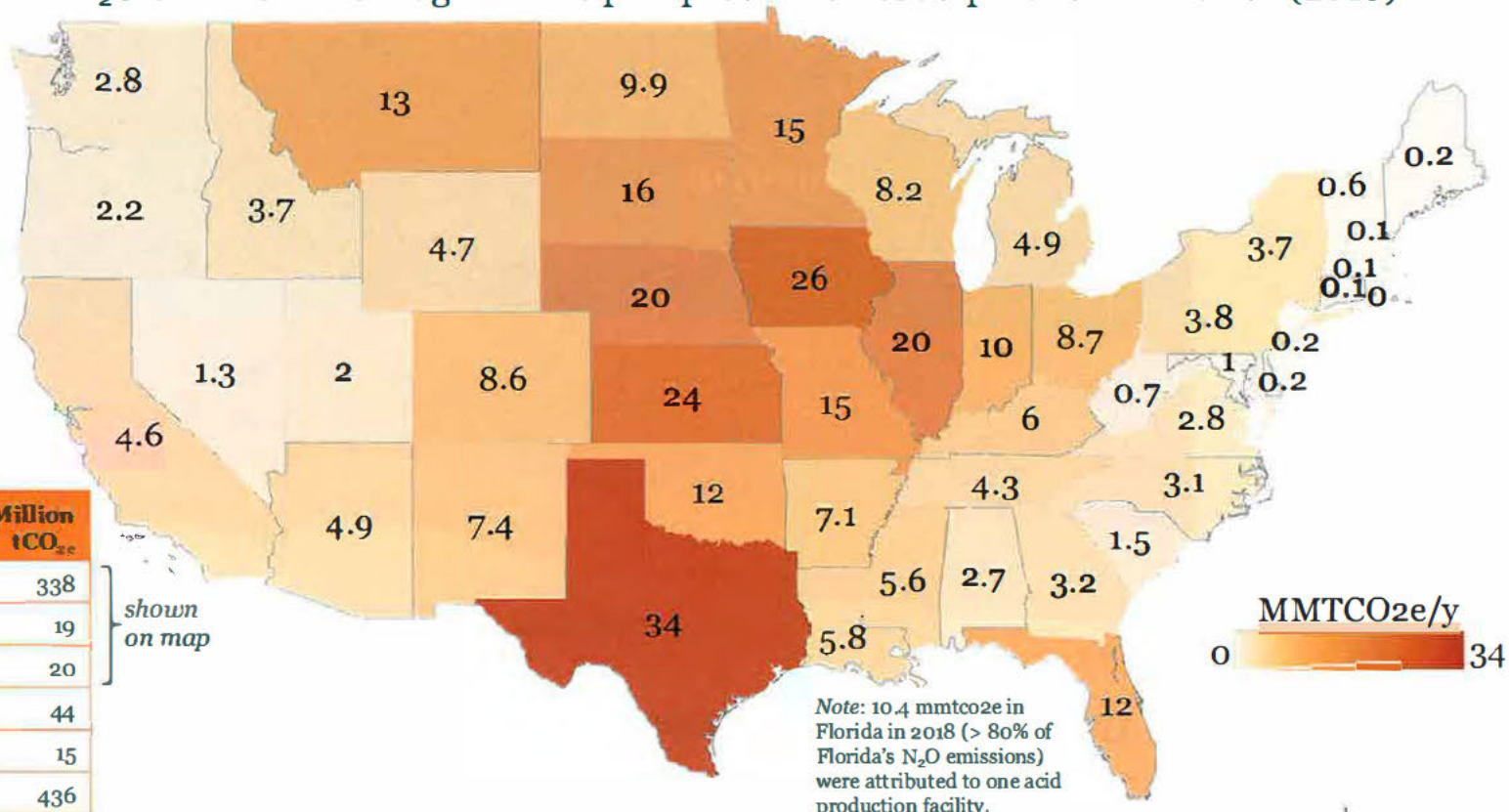
N_2O emissions occur mostly outside of the energy sector and in states with significant agricultural production.



N_2O emissions from agriculture plus production of adipic and nitric acids (2018)



Note: 10.4 mmtco2e in Florida in 2018 (> 80% of Florida's N_2O emissions) were attributed to one acid production facility.

N_2O emissions (2018)	Million tCO_{2e}
Agricultural soil management	338
Manure management	19
Adipic & nitric acid production	20
Stationary & mobile combustion	44
Other	15
Total	436

shown on map

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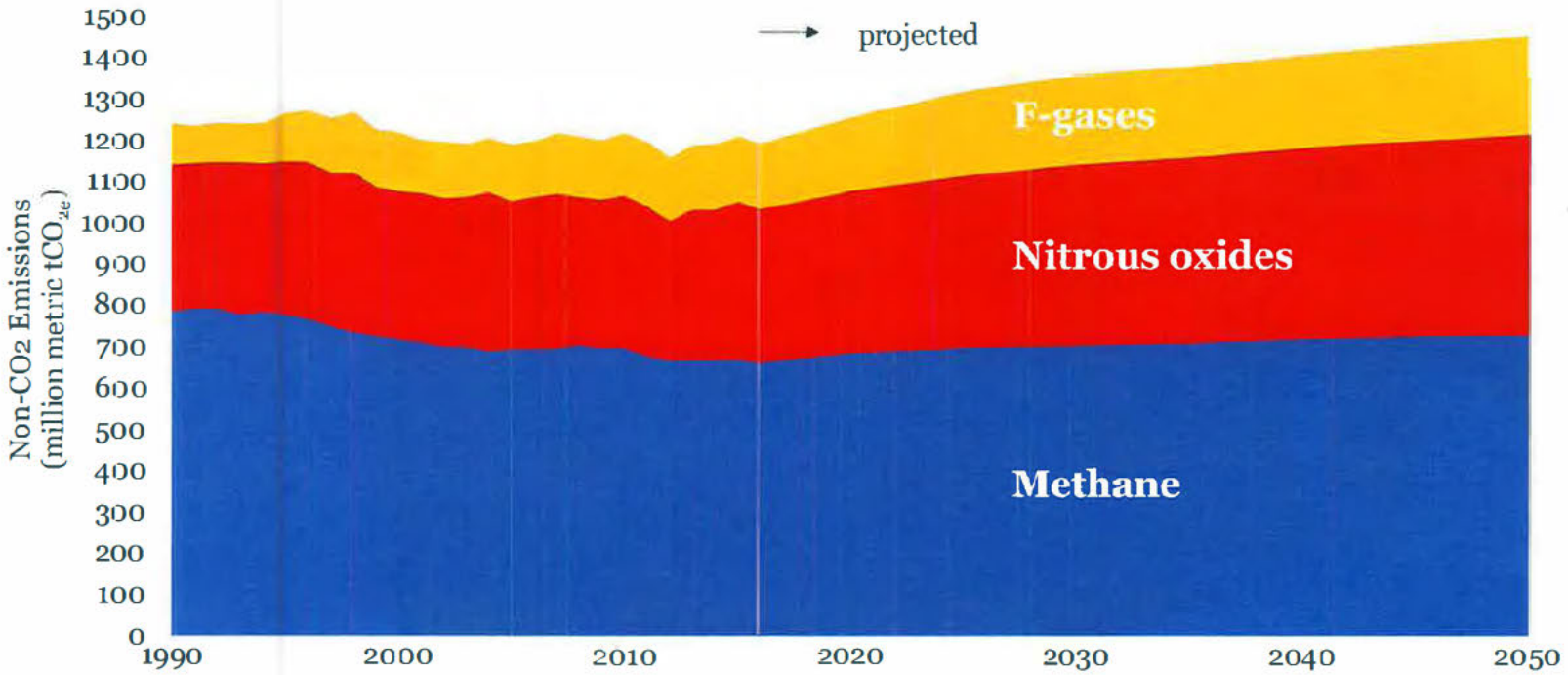
Carbon Mitigation Initiative

Without mitigation efforts, non-CO_2 emissions grow gradually to 1.45 $GtCO_{2e}$ by 2050, with CH_4 and N_2O contributing most

Historical and projected non-CO_2 emissions by gas type under business as usual (BAU)

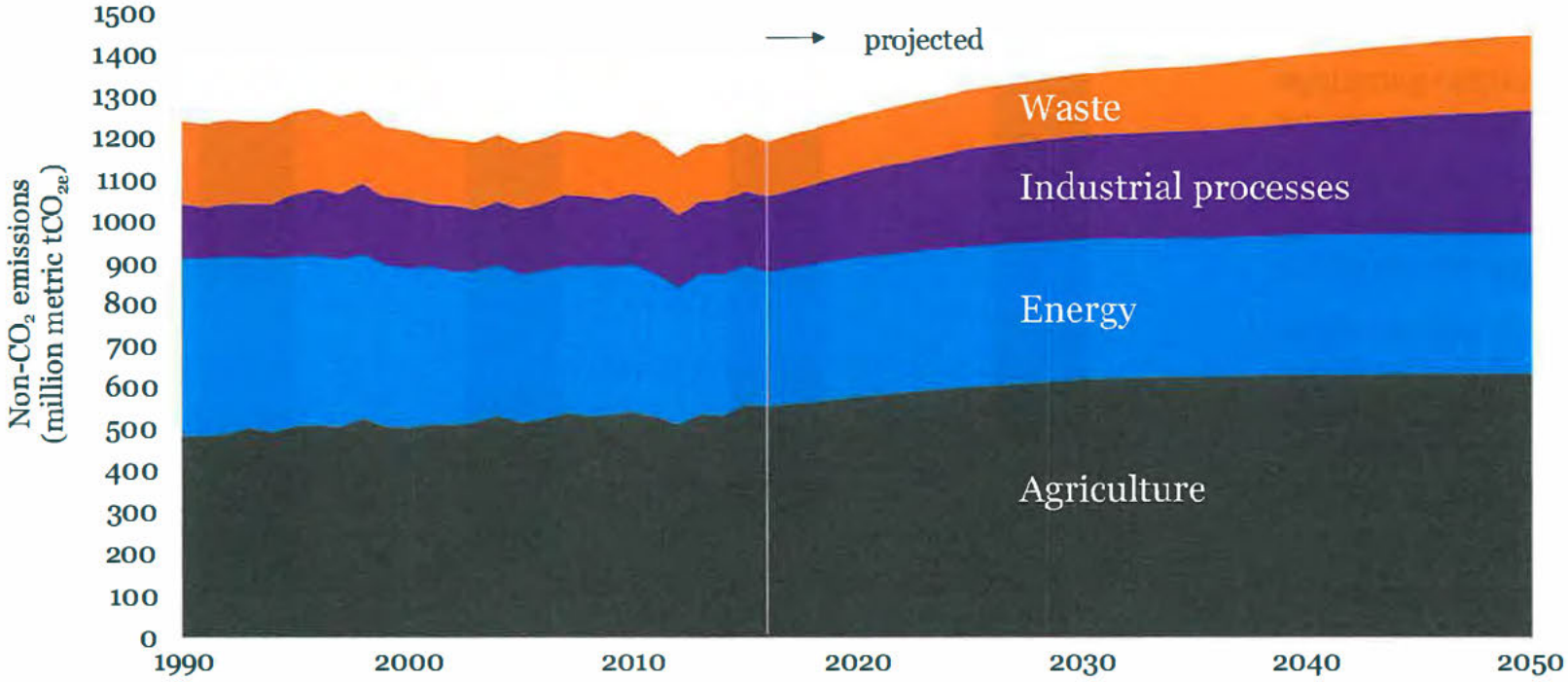


Source: EPA, *Global Non-CO_2 Greenhouse Gas Emission Projections & Mitigation*, Oct. 2019.

Without mitigation, non-CO_2 emissions grow gradually to 1.45 $GtCO_{2e}$ by 2050, with agriculture and energy remaining dominant



Historical and projected non-CO_2 emissions by sector under business as usual (BAU)

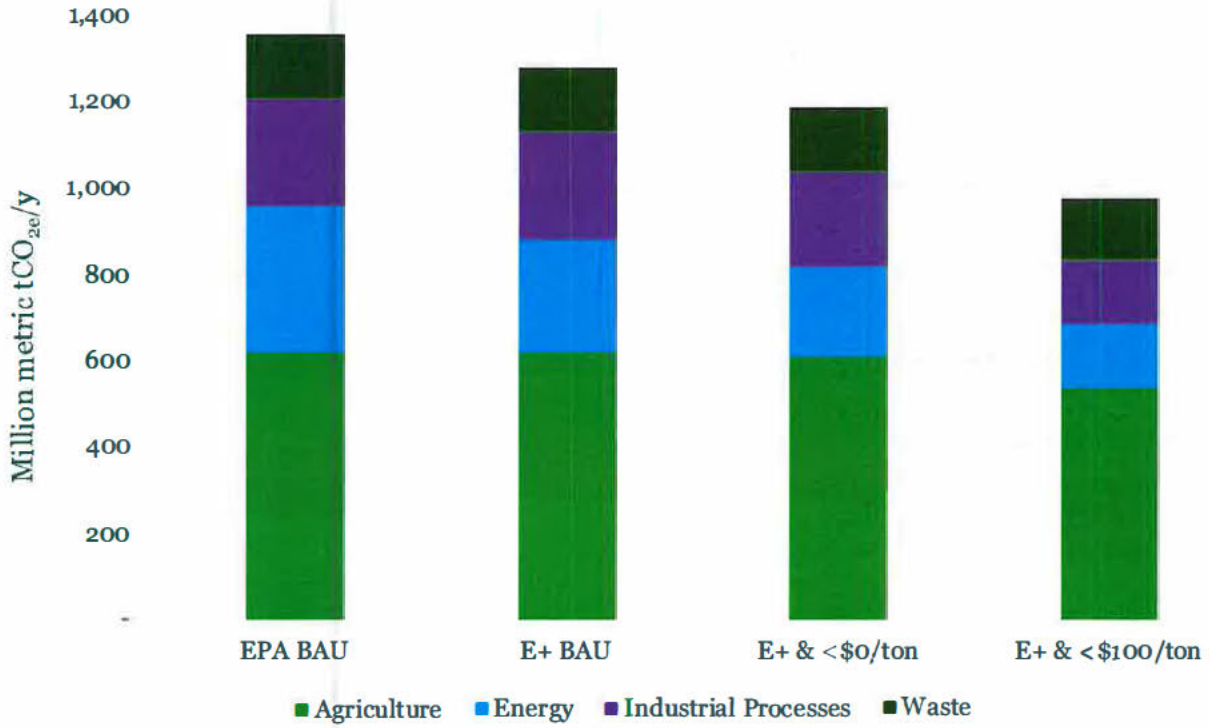


Source: EPA, *Global Non-CO_2 Greenhouse Gas Emission Projections & Mitigation*, Oct. 2019.

Mitigation can reduce non-CO_2 emissions substantially by 2030



2030 Non-CO_2 Emissions ($MtCO_{2e}$)



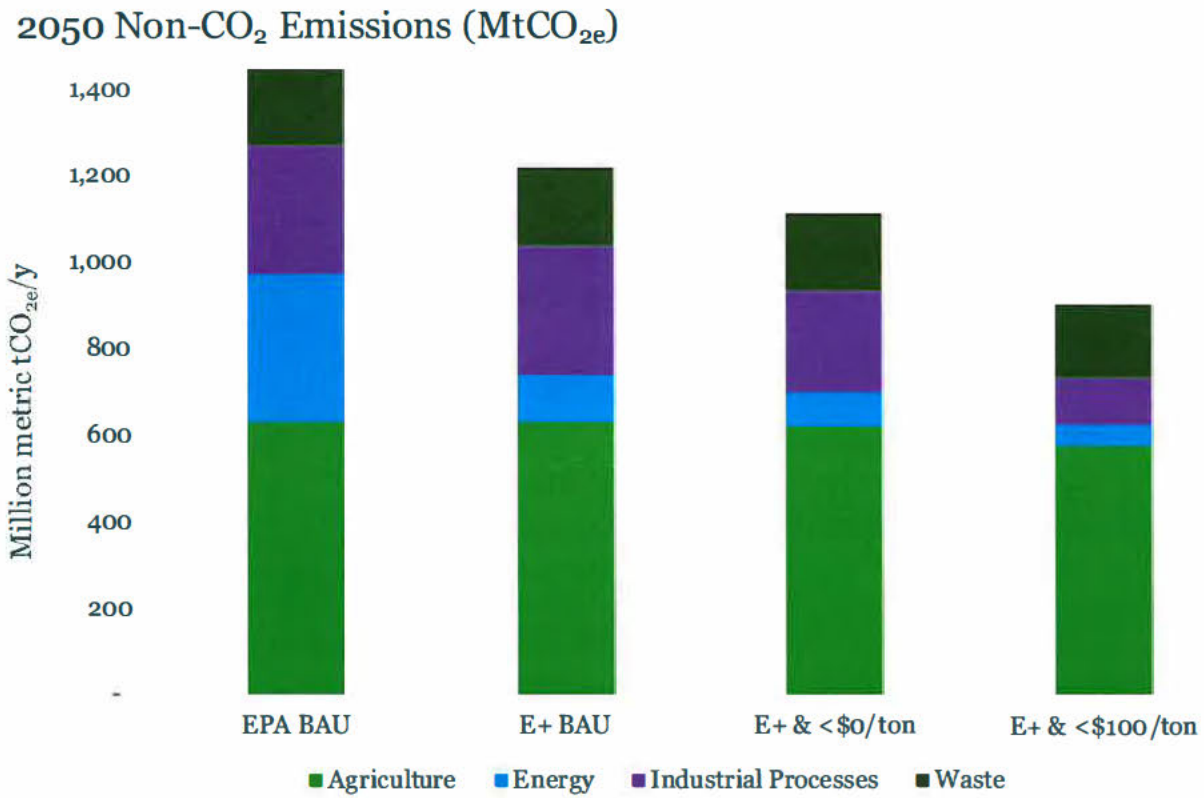
By 2030, EPA projects:

- Under EPA BAU (no mitigation), non-CO_2 emissions reach 1.35 $GtCO_{2e}$/y
- Under E+ BAU (energy mitigation but no non-CO2 mitigation), non-CO_2 emissions fall to 1.28 $GtCO_{2e}$/y as nearly all coal production ceases and oil/gas output drops ~10%
- Very low-cost mitigation yields 1.18 $GtCO_{2e}$/y while measures costing <$100/$tCO_{2e}$ yield 0.97 $GtCO_{2e}$/y
- Further research needed to identify additional reductions

Source: EPA, *Global Non-CO_2 Greenhouse Gas Emission Projections & Mitigation*, Oct. 2019, with adjustments for E+ scenario.

Mitigation can reduce emissions to ~1 Gt per year by 2050, but beyond that the path to deeper reductions remains uncharted





By 2050, EPA projects:

- Under EPA BAU (no mitigation), non-CO_2 emissions reach 1.45 $GtCO_{2e}$/y
- Under E+ BAU (energy mitigation but no non-CO2 mitigation), non-CO_2 emissions fall to 1.22 $GtCO_{2e}$/y as nearly all coal production ceases and oil/gas output drops ~75%
- Very low-cost mitigation yields 1.11 $GtCO_{2e}$/y while measures costing <$100/$tCO_{2e}$ yield 0.90 $GtCO_{2e}$/y
- E+ scenario assumes non-CO2 abatement efforts yield ~1 $GtCO_{2e}$/y by 2050

Source: EPA, *Global Non-CO_2 Greenhouse Gas Emission Projections & Mitigation*, Oct. 2019, with adjustments for E+ scenario.

Non-CO_2 emissions are reduced to 1 $GtCO_{2e}$ by 2050, or ~20% below 2020 and ~30% below BAU 2050 forecast from EPA.



Estimated abatement potential by 2050 @ ≤ \$100/tCO_{2e} avoided

	Source	2050 Abatement (10^6 tCO2e/y)
Agriculture	Croplands/Rice	11
	Livestock	49
Energy	Coal	5
	Oil and gas	48
Industrial	Nitric & Adipic Acid Production (N_2O)	36
	Refrigerants/AC (F-gases)	146
	Other	9.0
Waste	Landfill	13
	Total	**316**

Non-CO_2 Abatement Potential:

- Mitigation measures costing <\$100/tCO_{2e} can drive non-CO_2 emissions from 1.45 to 0.90 $GtCO_{2e}$/y by 2050
- F-gases account for nearly half of this mitigation potential

Source: EPA, *Global Non-CO_2 Greenhouse Gas Emission Projections & Mitigation*, Oct. 2019, but with coal and oil and gas adjustments to reflect E+ scenario: coal abatement is limited to mitigation of abandoned mines and oil/gas abatement is reduced by ~75% to account for lower oil production under E+.

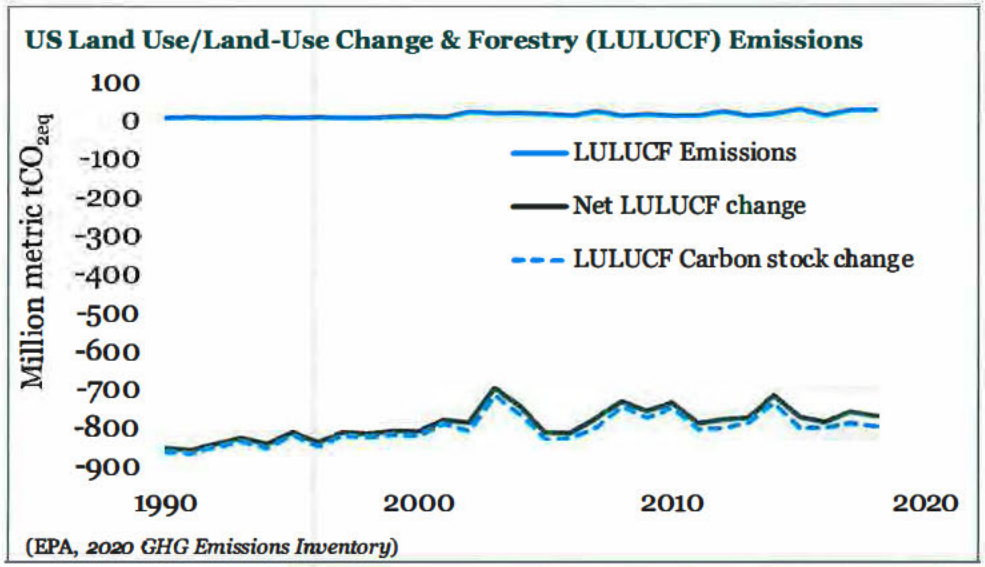
Pillar 6: Enhanced land sinks



Summary of this section

- Land carbon sinks, i.e., annual removal of carbon from the air and permanent storage in soil or trees, are critical for net-zero emission scenarios, because they offset positive greenhouse gas emissions from elsewhere in the economy.
- In the cost-minimized net-zero scenarios developed in this study, the last unit of CO_2 emission avoided from the energy/industrial system is the most expensive one to avoid. Thus, land sinks avoid using the most costly measures for CO_2 emissions reductions in the energy/industrial system.
- There is uncertainty about what the magnitude of the U.S. land since is today, but 0.7 $GtCO_{2eq}/y$ is thought to be a reasonable estimate, and there is an expectation that the natural land sink will weaken in the future to as low as 0.3 Gt/y by 2050 due to maturing of forest regrowth in the U.S.
- Geographically-resolved analysis by Net-Zero America researchers estimates a technical potential for enhanced land sinks by 2050 of up to 0.2 $GtCO_{2eq}/y$ in agriculture and from 0.5 to 1.5 $GtCO_{2eq}/y$ in forestry.
- The net-zero modeling in this study assumes the land sink grows to 0.85 $GtCO_{2eq}/y$ by 2050, which implies a concerted effort to deploy agricultural and/or forestry land sink enhancement measures.

Extent of carbon uptake in soils and trees impacts the decarbonization challenge for the energy/industrial system



- The current natural land sink is uncertain, but estimates are in the range of -0.7 $GtCO_{2e}/y$.
- Without efforts to enhance the natural land sink, it is projected to decline to -0.3 $GtCO_{2e}/y$ by 2050.
- Significant modification of agricultural and forestry practices, if widely adopted, can help maintain/enhance the land sink.

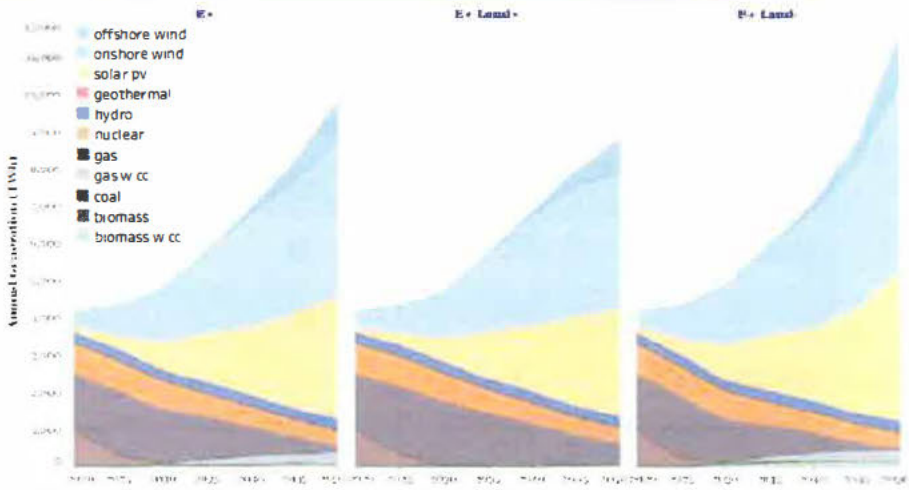
2050	E+ (and other scenarios)
Land sink, $GtCO_{2e}/y$ (assumed)	- 0.85
Non-CO2 emissions, GtCO2e/y (assumed)	1.02
Energy/industry emissions, $GtCO_2/y$	- 0.17

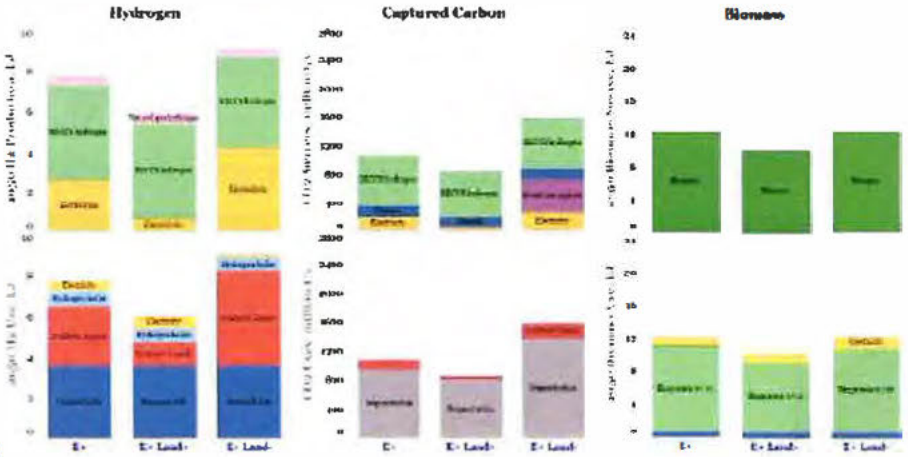
Non-CO_2 emissions and land carbon sinks impact the costs and emissions reduction efforts needed in the energy/industrial system

To reach net-zero emissions economy wide in 2050, emissions "allowed" by the energy/industrial system in 2050 depend on the net emissions occurring outside of energy/industry, i.e., land sinks and non-CO_2 emissions. The degree of net land sinks + non-CO_2 emissions that will be achieved is uncertain. Compared with E+:

- If the net outside emissions are higher (E+ Land-), electricity generation is much higher by 2050, with most of the increase being solar and wind. Electrolytic H_2 production is also higher, deployment of direct air capture is significant, and about 60% more CO_2 sequestration is required. NPV of the total energy-supply system (2020 – 2050) increases by 3%.
- If the net outside emissions by 2050 are lower E+ Land+), less total electricity is needed in 2050, and a greater fraction comes from NGCC without CC. There is also less H_2 demand because more petroleum-derived fuels can be used. NPV of the total energy-supply system (2020 – 2050) decreases by 2%.

Input assumptions that vary between cases			
Billion metric tCO_{2e} in 2050	**E+**	**E+ Land+**	**E+ Land-**
Land sink	- 0.85	- 1.30	- 0.30
Non-CO2 emissions	1.02	1.02	1.02
Net emissions outside of energy/industry system	0.17	- 0.27	0.73
Allowed energy/industrial CO_2 emissions in 2050	- 0.17	0.27	- 0.73





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Agricultural measures can yield > 200 million tCO_{2e}/y of additional carbon storage in soils by 2050*



With 100% adoption of conservation measures	E+		E- B+	
	10^6 ha	10^6 tCO_{2e}/y	10^6 ha	10^6 tCO_{2e}/y
Ethanol-corn land → perennial energy grasses	11	23	11	23
CRP area converted to perennial energy grasses	12	0	12	0
Other croplands converted to				
perennial energy grasses	0	0	10	16
woody energy crops	0	0	1	no estimate
permanent herbaceous cover	13	7	12	7
Pasture converted to perennial energy crops	0	0	15	no estimate
Other croplands remaining as cropland	136	204	127	189
Pasture remaining as pasture	155	no estimate	140	no estimate
Totals	**327**	**234**	**327**	**233**

* See Swan, et al. (Annex Q).

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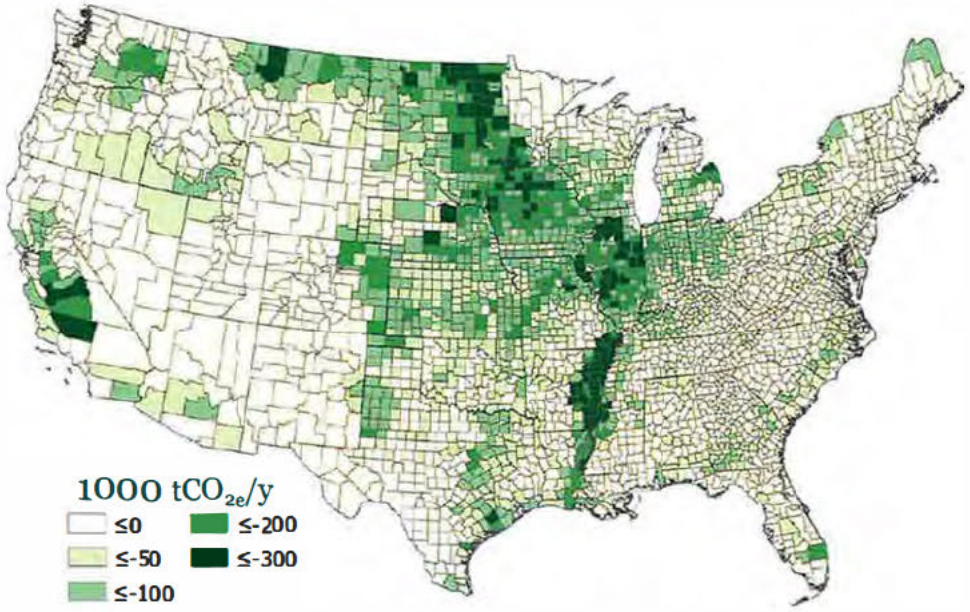
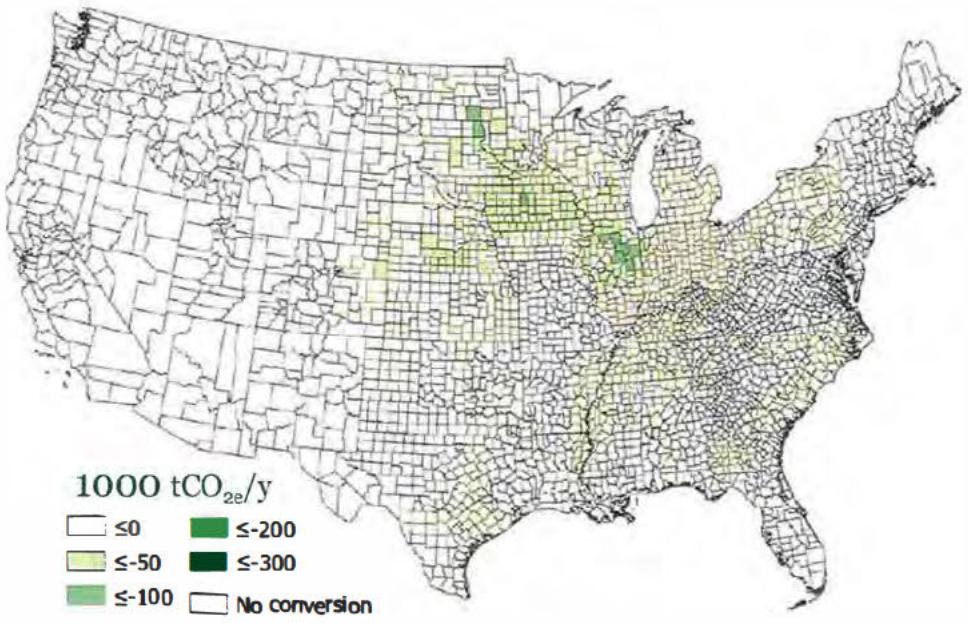
Maximum annual carbon uptake potential on agricultural lands by county; Midwestern states account for >80% of the potential.

Carbon storage across all agricultural lands (160 million ha)



Total U.S. potential: 230 million tCO_{2e}

Carbon storage on ethanol-corn land converted to energy grasses (11 Mha)



Total U.S. potential: 23 million tCO_{2e}

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See Swan, et al. (Annex Q).

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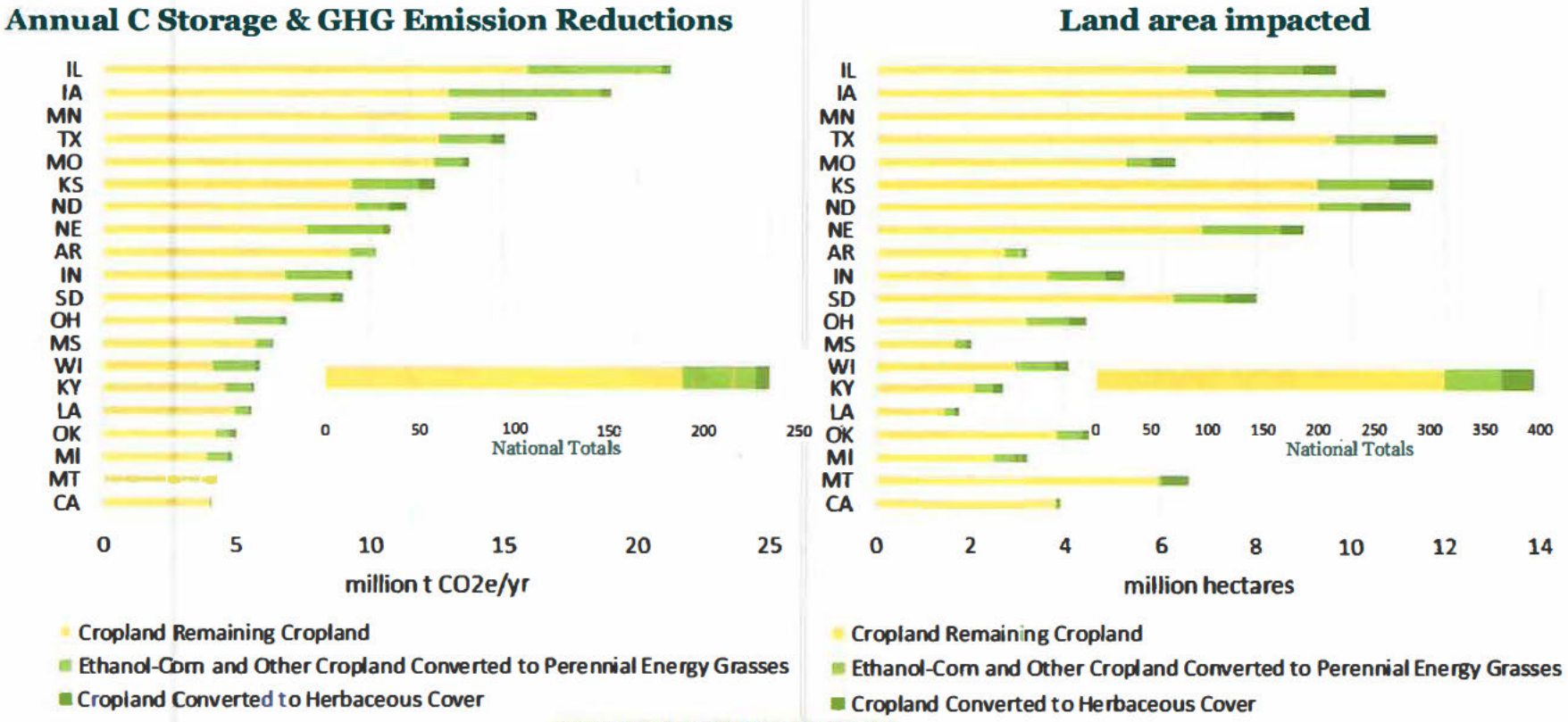
Top 20 states account for > 85% of the carbon storage potential on agricultural lands in 2050 (E+ scenario)

Most of the potential is in measures applied to cropland, with carbon storage per acre averaging 1.5 tCO_{2e}/ha); ethanol-corn land conversion to energy grasses is highest (2.1 tCO_{2e}/ha).



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Technical potential for carbon uptake by forest measures is estimated to be 0.5 to 1.5 $GtCO_{2e}/y$.*

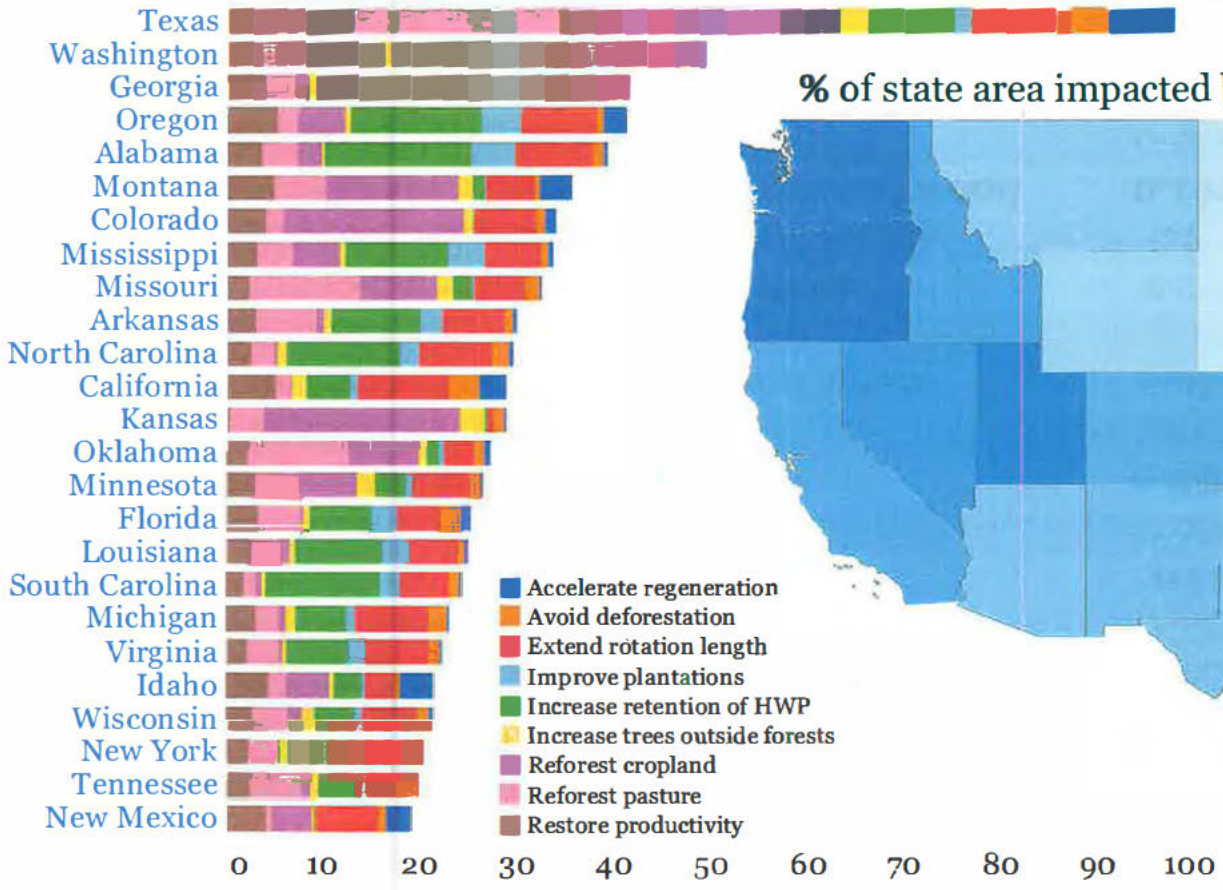


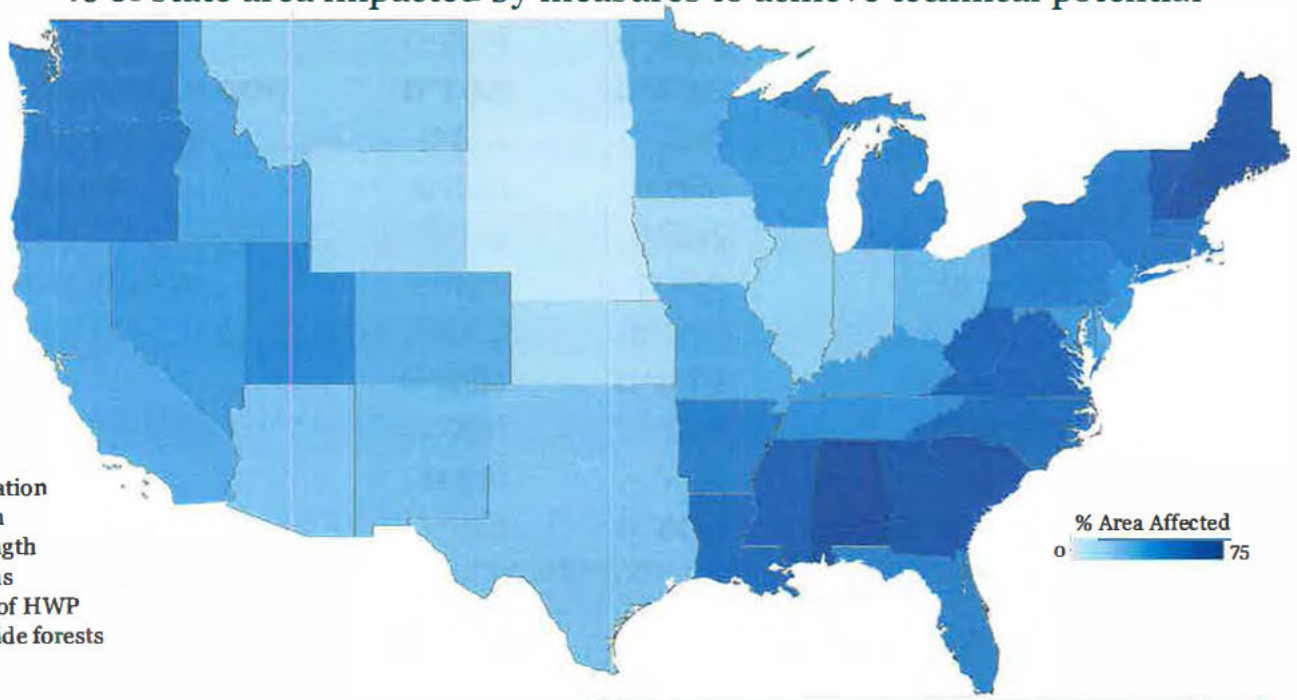
Activity	Low Estimate ($GtCO_{2e}/y$)	High Estimate ($GtCO_{2e}/y$)	Land area affected (million ha)
Reforestation of agricultural lands (a)	**0.141**	**0.506**	**9 – 34**
Croplands	0.121	.242	8 – 16
Pasture	0.020	.264	1.3 – 17.5
Improved forest management	**0.250**	**0.644**	**112 – 297**
Accelerate regeneration	0.025	0.049	4 – 8
Restore productivity of degraded forests	0.060	0.178	36 – 154
Extend rotation lengths	0.116	0.302	59 – 154
Improve productivity of plantations	0.029	0.057	11 – 21
Increase stocking of trees outside forests	0.021	0.060	3 – 6
Increased C retention in harvested wood	**0.100**	**0.300**	**n/a**
Reduced deforestation	**0.014**	**0.084**	**11**
Total potential	**0.500**	**1.53**	**132 – 342**

(a) Agricultural lands that are assumed to otherwise be enrolled as Conservation Reserve Program acreage.

* See Birdsey, 2020 (Annex P).

1 GtCO2e/y technical potential for enhanced carbon storage on forest lands (mid-range of estimates)





25 states shown in the bar graph have 80% of total US technical potential

* ≥ 130 Mha, or more than ½ of all forest area, are impacted.

Six-pillars' summary: Rapid expansion for 3 decades, such that by 2050…



1. Efficiency & Electrification

Consumer energy investment and use behaviors change

- 300 million personal EVs
- 130 million residences with heat pump heating

Industrial efficiency gains

- Rapid productivity gain
- EAF/DRI steel making

2. Clean Electricity

Wind and solar

- Rapidly site 10s-100s of GW per year, sustain for decades
- 3x to 5x today's transmission

Nuclear

- In RE- scenario site up to 250 new 1-GW reactors (or 3,800 SMRs).
- Spent fuel disposal.

NGCC-CCS

- In RE-, 300+ plants (@750 MW)

Flexible resources

- Combustion turbines w/high H_2
- Large flexible loads: electrolysis, electric boilers, direct air capture
- 50 - 180 GW of 6-hour batteries

3. Zero-Carbon Fuels

Major bioenergy industry

- 100s of new conversion facilities
- 620 million t/y biomass feedstock production (1.2 Bt/y in E- B+)

H_2 and synfuels industries

- 8-19 EJ H_2 from biomass with CCS (BECCS), electrolysis, and/or methane reforming
- Largest H_2 use is for fuels synthesis in most scenarios

4. CO_2 capture & storage

Geologic storage of 0.9 – 1.7 $GtCO_2/y$

- Capture at ~1,000+ facilities
- 21,000 to 25,000 km interstate CO_2 trunk pipeline network
- 85,000 km of spur pipelines delivering CO_2 to trunk lines
- Thousands of injection wells

5. Non-CO_2 Emissions

Methane, N_2O, Fluorocarbons

- 20% below 2020 emissions (CO_{2e}) by 2050 (30% below 2050 REF).

6. Enhanced land sinks

Forest management

- Potential sink of 0.5 to 1 $GtCO_{2e}/y$, impacting ½ or more of all US forest area (≥ 130 Mha).

Agricultural practices

- Potential sink ~0.20 $GtCO_{2e}/y$ if conservation measures adopted across 1 – 2 million farms.

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Implications of net-zero transitions



Summary of this section

- Significant implications of transitions to net-zero emissions are illustrated quantitatively here for land use, capital mobilization, fossil fuel industries, employment, and air pollution-related health impacts.

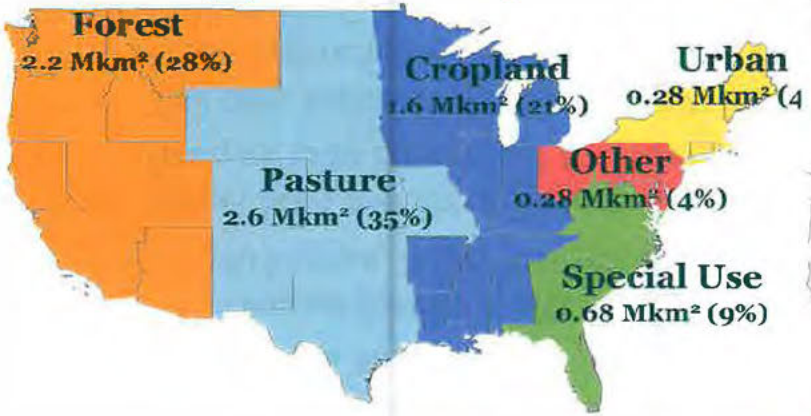
Land use



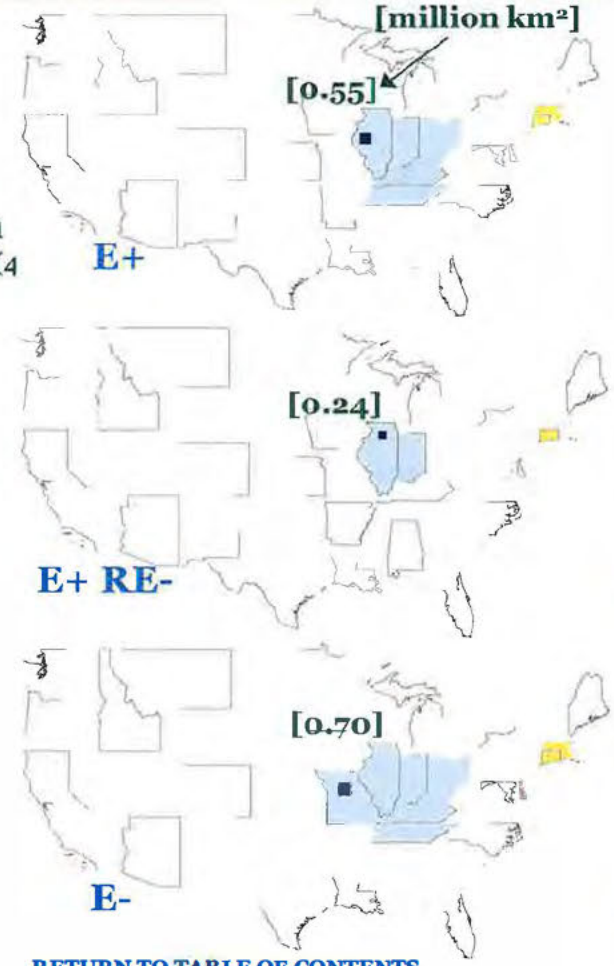
Summary of this section

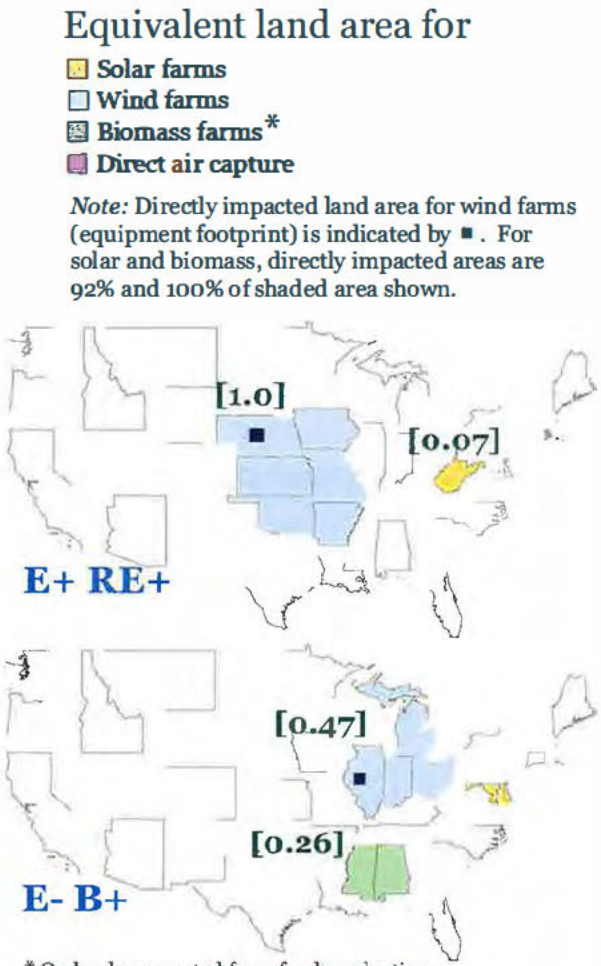
- The direct land use for wind turbine construction in net-zero scenarios is small, but the (visual) footprint of wind farms is significant. In 2050, total wind farm area is
  - Smallest for the E+ RE- scenario: ~¼ million km², or the equivalent of the combined land areas of Illinois and Indiana.
  - Largest for the E+RE+ scenario: 1 million km², or the equivalent of the combined land areas of Arkansas, Iowa, Kansas, Missouri, Nebraska, and Oklahoma.
- Direct land use for solar farms in 2050 is much smaller than the visual footprint of wind farms, ranging from an area equivalent to the area of Connecticut for E+ RE- to that of Virginia for E+ RE+.
- The only scenario for which there is significant land-use change associated with biomass use is in the E- B+ scenario, where land area equivalent to the combined areas of Alabama and Mississippi (> ¼ million km²) is converted from food agricultural uses to dedicated cultivation of perennial energy crops.

Total land area/visual footprint in 2050 for solar, wind, and biomass across scenarios is 0.25 to 1.1 million km².



Note: In these maps, the sum of land areas of colored states is roughly the same as the area nationally of the indicated uses.





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* On lands converted from food production.

Capital mobilization



Summary of this section

- **All net-zero scenarios are more capital intensive than REF scenario**, and so critically depend on timely mobilization of large sums of capital. Capital investments are long-lived, so timing of investments and divestments are critical.
- E+ requires mobilization of about **2.6 T$ of energy supply-side risk-capital before 2030**, and **10 T$ trillion by 2050** [and additional demand-side capital investments].
- 'Risk-capital' refers to capital committed prior to Commercial Operation Date (COD) which is exposed to various development, market, construction and technology performance risks which could impact project cashflows and hence project valuation. These risks may limit the availability, and increase the cost, of investment capital.
- NZA models assume a rational and efficient market that sees investors respond instantly to incentives to mobilize capital overnight; but in reality, capital is mobilized through a sequence of decisions and activities which require considerable lead times and resources.
- E+ requires on the order of **190 B$ of pre-FID development costs before 2030** and **600 B$ by 2050**, typically spent 1-5 years in advance of committing above multi-trillion dollar investments. These costs are **fully at-risk**, since as there is no guarantee that a given project will proceed past a final investment decision (FID) to generate value, and therefore **subject to availability of developer equity**.
- Net-zero scenarios are characterized by a high degree of foresight and seamless integration between sectors; but investors face deep uncertainty around future technology costs and performance, policy priorities of future governments, investment preferences among peers, customers and competitors, and public acceptance of certain technologies.
- Gaps between our modeling and the real world of investment decisions obscure a number of potential challenges to mobilizing risk-capital for project development and construction that must be mitigated through policy mechanisms to meet the 2050 net-zero target.
- Such mechanisms include investment during the 2020's to create *real options* for technologies needed post 2030, including: multiple full-scale 'first-N-of-a-kind' projects to de-risk and reduce the cost of less mature technologies; and investment in critical enabling infrastructure (e.g. electricity transmission and CO_2 pipelines) to serve various future supply-side investments.

To avoid lock-in and reduce cost of transition, net-zero pathways capitalize on timing of stock turnover for long-lived assets

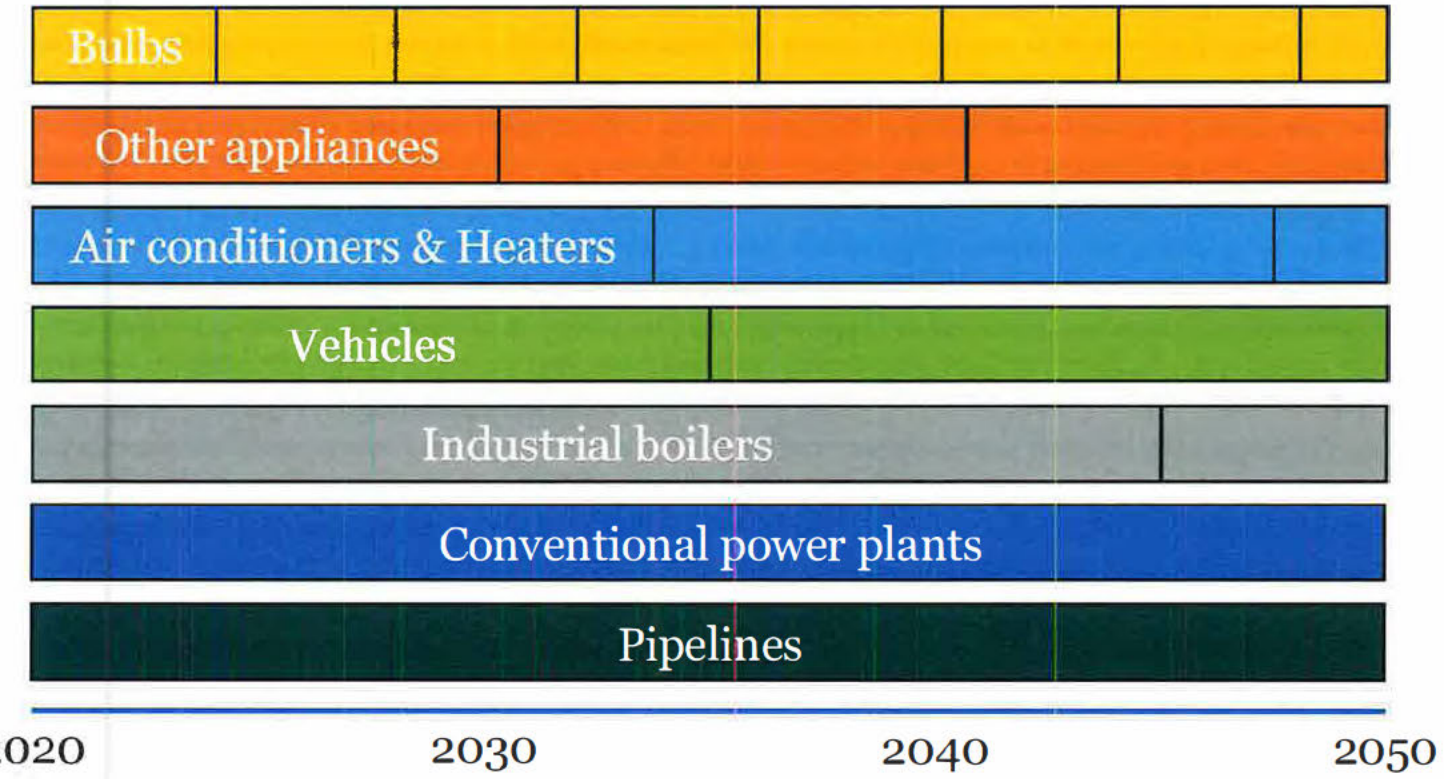
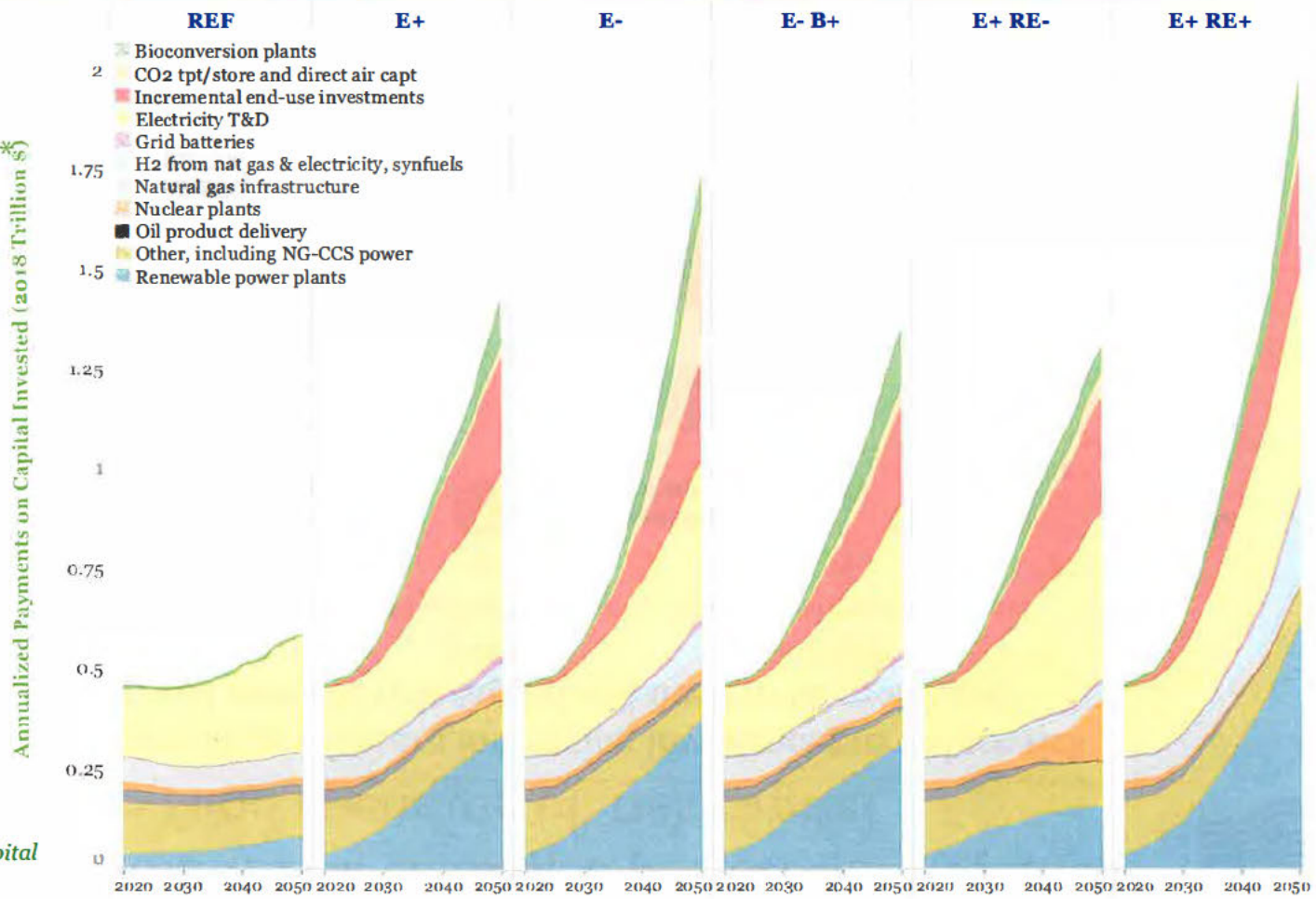


Image credit: Ryan Jones, Evolved Energy Research

Capital dominates energy system costs in net-zero pathways: annualized payments on capital by 2050 are 2 to 4 times REF.

- Capital-investment decision processes typically involve greater pre-investment capital-at-risk and corporate scrutiny than operating-cost decisions.
- The sheer number of capital decisions implied in these pathways represents a challenge for the transition schedule.
- Policy environment will be a key determinant of pace/scale of capital investment.



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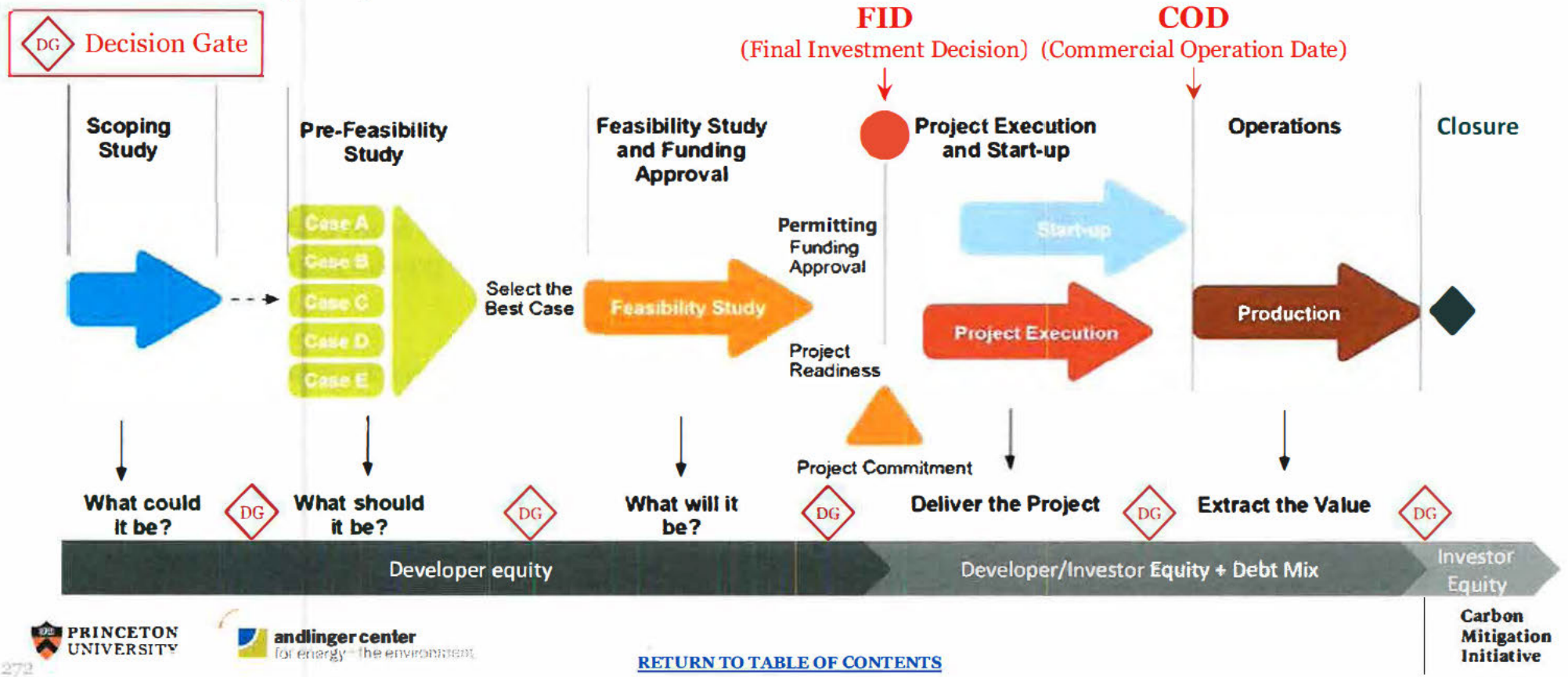
* *Includes payments on capital plus fixed O&M charges*

Capital investments will follow risk-managed project development, requiring time (for studies) and spending of 'risk capital'

Project decision-gated sequence, where stages feature increasing investment to reduce risk and uncertainty, implies that substantial sums of risk capital will need to be mobilized:



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An extensive set of activities must happen before final investment decision (FID)



- Stage-gate decisions are informed by activities, the scopes of which include, but aren't limited to:
  - Engineering, logistics and cost estimating;
  - Resource characterization;
  - Site evaluation and selection;
  - Environmental and social impact assessments;
  - Stakeholder engagement;
  - Land access agreements
  - Market analysis and offtake agreements;
  - Technology license agreement;
  - EPC contract negotiations;
  - Permitting & licensing.
- Pre-FID activities are generally equity funded and entirely 'at-risk'; not all proposed projects will achieve FID, so estimation of study costs must allow for a percentage of 'failure cases'.
- Post-FID, the majority of projects will be project financed using a mix of debt and equity; debt finance will be subject to finance fees that must be paid before first drawdown (i.e., at FID).
- Historical experience is that depending on the risk profile, debt funds and some classes of equity investment funds may be attracted to invest only after commercial operations have commenced (COD).
- Pre-FID investment costs, lead-times and success rates (move from FID to COD), along with construction times for each technology were estimated on the basis of the NZA team's industrial experience, and expert judgement.

Estimated project development times and pre-FID costs (Power Sector)



POWER SECTOR

Generation

Technology	Pre-FID Study Time (years)	PreFID Cost[1] (% of TIC)	Financing Cost[2] (% of TIC)	Total Pre-FID Cost (% of TIC)	Financial Close (years)	Construction Time (years) FID to COD	Overall Dev Time (years) Concept to COD
biomass w cc	2.5	9.0%	1.5%	10.5%	0.5	4	7
CCGT	1	4.5%	1.0%	5.5%	0.5	2	3.5
CCGT w CC	2.5	9.0%	1.5%	10.5%	0.5	4	7
CT	1	4.5%	1.0%	5.5%	0.5	1	2.5
geothermal	2	9.0%	1.0%	10.0%	0.5	2	4.5
nuclear	5	24.1%	3.0%	27.1%	1	5	11
offshore wind	2.5	10.0%	1.5%	11.5%	0.5	3	6
onshore wind	1.5	5.5%	1.0%	6.5%	0.5	2	4
solar pv	1	5.5%	1.0%	6.5%	0.5	1	2.5
storage li-ion	1	4.5%	1.0%	5.5%	0.5	1	2.5

Transmission

Technology	Pre-FID Study Time (years)	Pre-FID Study Cost[1] (% of TIC)	Financing Cost[2] (% of TIC)	Total Pre-FID Cost (% of TIC)	Financial Close (years)	Construction Time (years) FID to COD	Overall Dev Time (years) Concept to COD
Transmission Assets (average)	2.5	5.7%	1.0%	6.7%	0.5	4	7

Distribution Networks

Technology	Pre-FID Study Time (years)	PreFID Study Cost[1] (% of TIC)	Financing Cost[2] (% of TIC)	Total Pre-FID Cost (% of TIC)	Financial Close (years)	Construction Time (years) FID to COD	Overall Dev Time (years) Concept to COD
Distribution Assets	1	2.5%	0.5%	3.0%	0.5	1	2.5

Estimated project development times and Pre-FID costs (Fuels, CO2 Infrastructure, and Industry)



Technology	Pre-FID Time (years)	Pre-FID Cost[1] (% of TIC)	Financing Cost[2] (%of TIC)	Total Pre-FID Cost (% of TIC)	Financial Close (years)	Construction Time (y) FID to COD	Overall Dev Time (y) Concept to COD
FUELS CONVERSION							
ATR Hydrogen	2	4.5%	1.0%	5.5%	1	2	5
ATR Hydrogen with CCU	2	9.0%	1.5%	10.5%	2	3	7
BECCS Hydrogen	2	9.0%	1.0%	10.0%	2	4	8
Biomass to Syngas	2	9.0%	1.5%	10.5%	2	3	7
Biomass to Syngas with CCU	2	9.0%	1.0%	10.0%	2	4	8
Biomass FT to Diesel	2	9.0%	1.0%	10.0%	2	3	7
Biomass FT to Diesel with CCU	2	9.0%	3.0%	12.0%	2	4	8
Biomass Pyrolysis	2	4.5%	1.5%	6.0%	2	3	7
Biomass Pyrolysis with CCU	2	9.0%	1.0%	10.0%	2	4	8
Electrolysis	2	4.5%	1.0%	5.5%	1	2	5
DAC for Synfuels	2	9.0%	1.0%	10.0%	1	2	5
Electric Boiler	2	9.0%	1.0%	10.0%	2	1	5
Hydrogen Blend	1	4.5%	1.0%	5.5%	1	1	3
Industrial Hydrogen Boiler	2	4.5%	1.0%	5.5%	1	2	5
Industrial Pipeline Gas Boiler	2	4.5%	1.0%	5.5%	1	1	4
Power to Liquids	2	9.0%	1.0%	10.0%	1.5	3	6.5
Power to Gas	2	9.0%	1.0%	10.0%	1.5	3	6.5
CO2 TRANSPORT & STORAGE							
Inter-Regional Trunk Lines	5	13.0%	1.5%	14.5%	1	5	11
Spur Lines	2.5	4.2%	1.0%	5.2%	0.5	3	6
E&A, Wells & Facilities	1	5.0%	0.0%	5.0%	0	1	2
INDUSTRY							
Cement	2.5	4.2%	1.0%	5.2%	0.5	4	7
Steel	2.5	4.2%	1.0%	5.2%	0.5	3	6

The 2020s is the decade to invest in maturing and improving a range of technologies that improve options for the longer term.



- Several technologies will require multiple full-scale 'first-N-of-a-kind' (FOAK) projects to reduce costs and technology risks.
- Assumed investment premium is estimated at 150% over and above reference costs across pre-FID, design, construction and commissioning.

	FOAK Project unit Capacity	No. of Projects	Mature cost* (used in RIO model)	FOAK cost multiplier on mature cost**	Total FOAK Investment (B$)
Power		**27**			**63.3**
Advanced Nuclear	300 MW	4	6,465 $/kW	2.5	19.4
CCGT with CC	300 MW	5	2,176 $/kW	2.5	8.2
CCGT with CC (Oxy)	300 MW	5	1,924 $/kW	2.5	7.2
Bio-gasifier GT with CC	300 MW	5	6,338 $/ kW	2.5	23.8
High-H_2 GT	100 MW	5	520 $/kW	2.5	0.7
Advanced Geothermal	100 MW	3	5,472 $/kW	2.5	4.1
Fuels		**30**			**24.8**
ATR Hydrogen with CC	300 MW	5	782 $/kW	2.5	2.9
Bio-gasifier H_2 with CC	300 MW	5	2,599 $/kW	2.5	9.7
Biomass Pyrolysis	100 MW	5	3,991 $/kW	2.5	5.0
Electrolysis	100 MW	10	1,790 $/kW	2.5	4.5
Direct Air Capture	100 ktpa	5	18,954 $/ktph CO_2	2.5	2.7
Industry		**10**			**48.8**
Cement with CC	2.8 Mtpa	5	3.5 B$/plant	2.5	43.8
H_2-Direct Reduced Iron	2.25 Mtpa	5	400 M$/plant	2.5	5.0
Total		**67**			**136.9**

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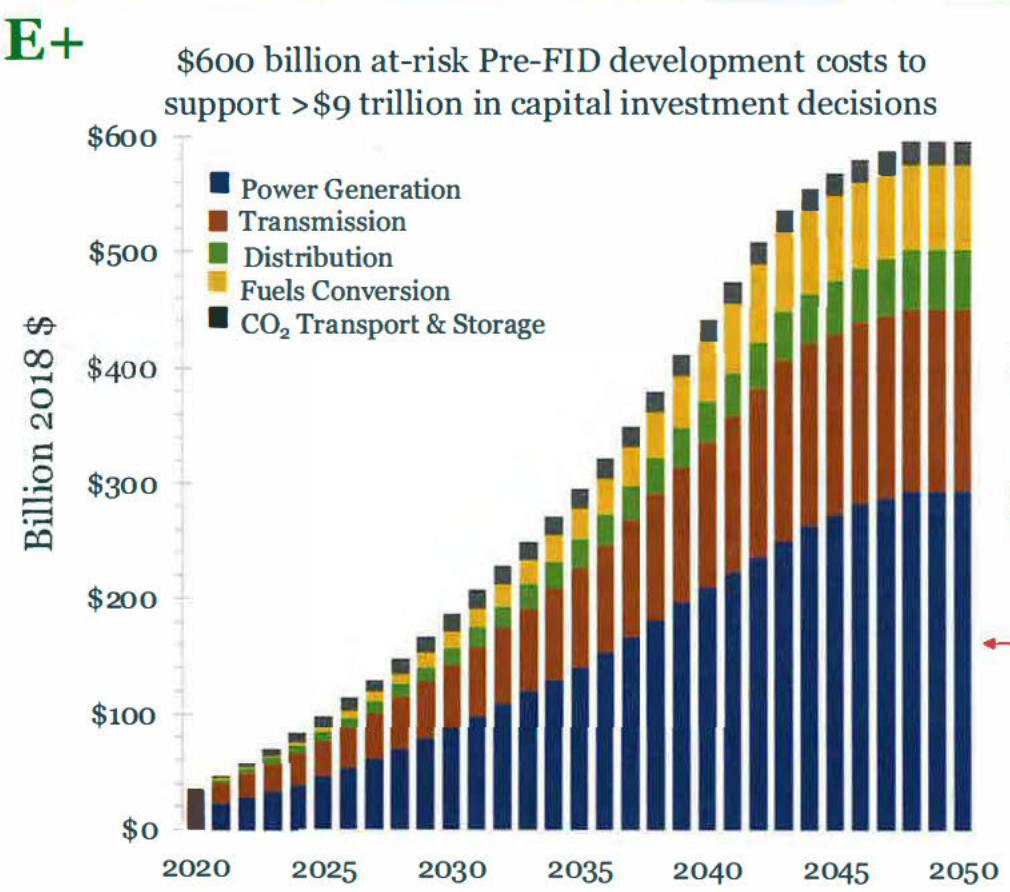
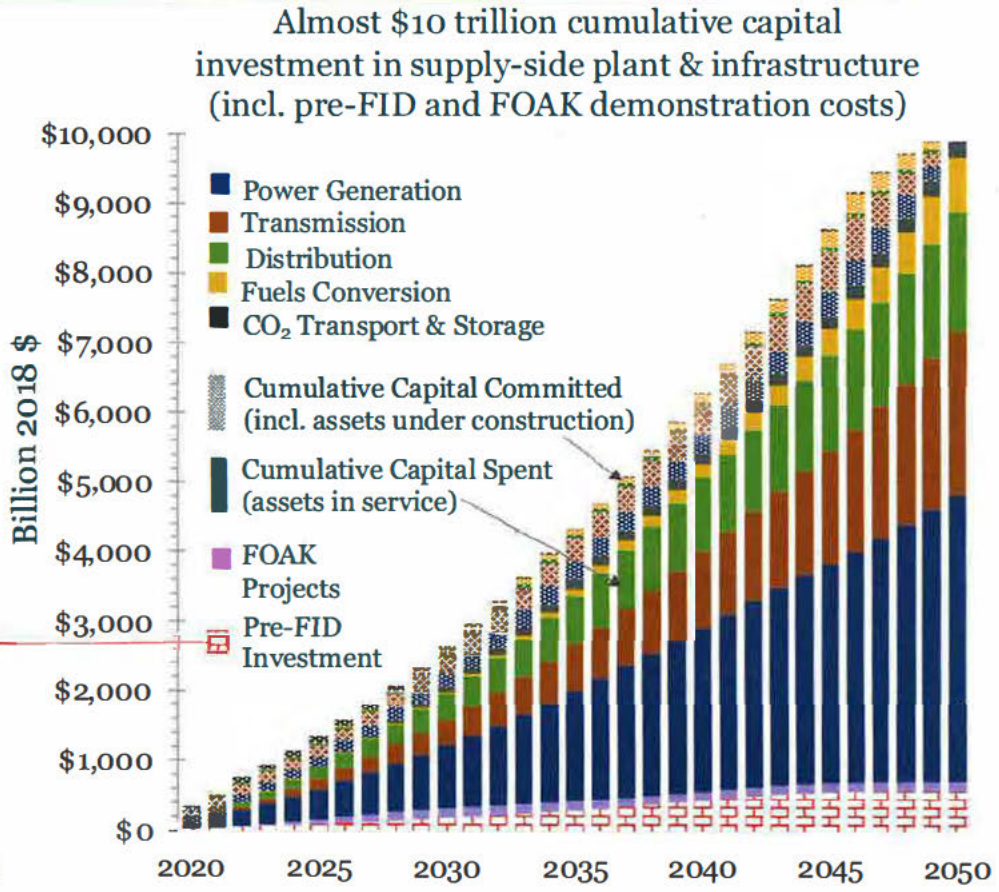
* Overnight installed capital cost per unit output. For fuels, output is expressed on a higher heating value basis.
** Including pre-FID, based on Guidelines for First-of-a-kind Cost estimation [1.5 applies to FOAK plants already committed in 2020's]

All net-zero scenarios are capital intensive. Mobilizing risk capital for development and construction will be a significant challenge

E+





Note: Excludes investments in demand-side transport, buildings and industry; biomass crop establishment; and land sink enhancements.

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Fossil fuel industries



Summary of this section

All fossil fuel industries see rapidly declining consumption and production throughout the transition.

Thermal coal consumption and production ceases by 2030.

- Over 700 coal mines close and some 500 coal-fired power plants are retired.
- The majority of coal plants retire at >30 years age, with just 8% retiring at <20 years and 50% retiring at >50 years.

Oil production declines 25% to 85% across the suite of NZA scenarios, relative to the reference scenario

- Consumption declines 60% to 100% by 2050 in net-zero scenarios.
- Exports remain in line with AEO projections to 2050.
- Oil production to 2050 in net-zero scenarios exceeds current proven reserves, but is less than projected reserves based on recent growth rates.

Natural gas production declines between 20% and 90% across the suite of NZA scenarios, relative to the reference scenario

- Consumption declines 50% to 100% by 2050 in net-zero scenarios.
- Exports remain in line with AEO projections to 2050.
- Significant declines in revenues for producers and bringing forward some $25 billion in remediation costs.
- Gas production in to 2050 in net-zero scenarios exceeds current proven reserves, but is less than projected reserves based on historical growth rates.
- Significant stranded asset risks for transmission and distribution networks.

Coal

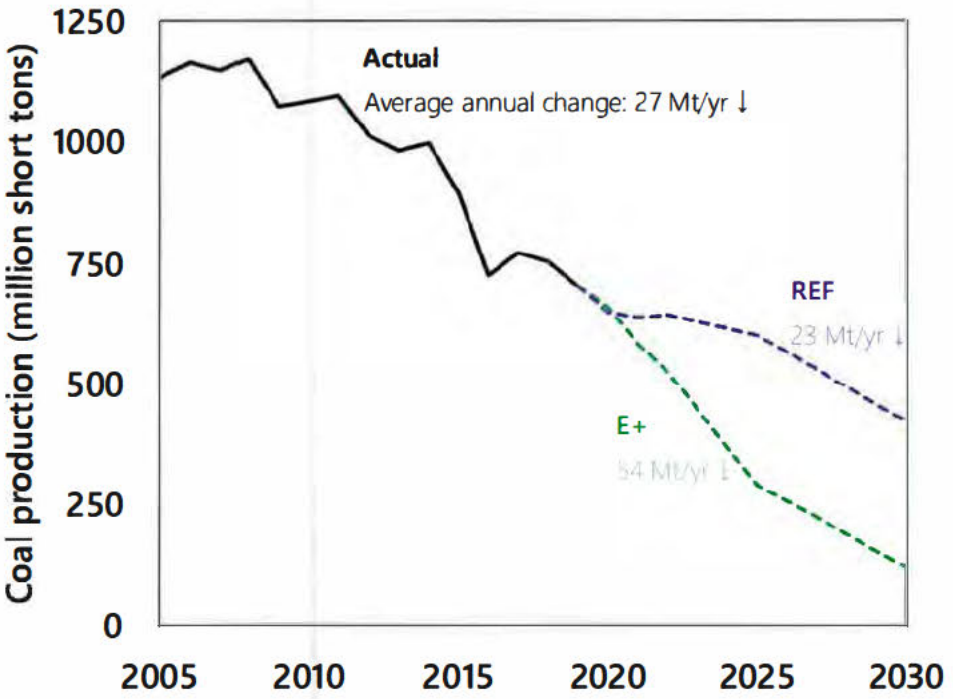


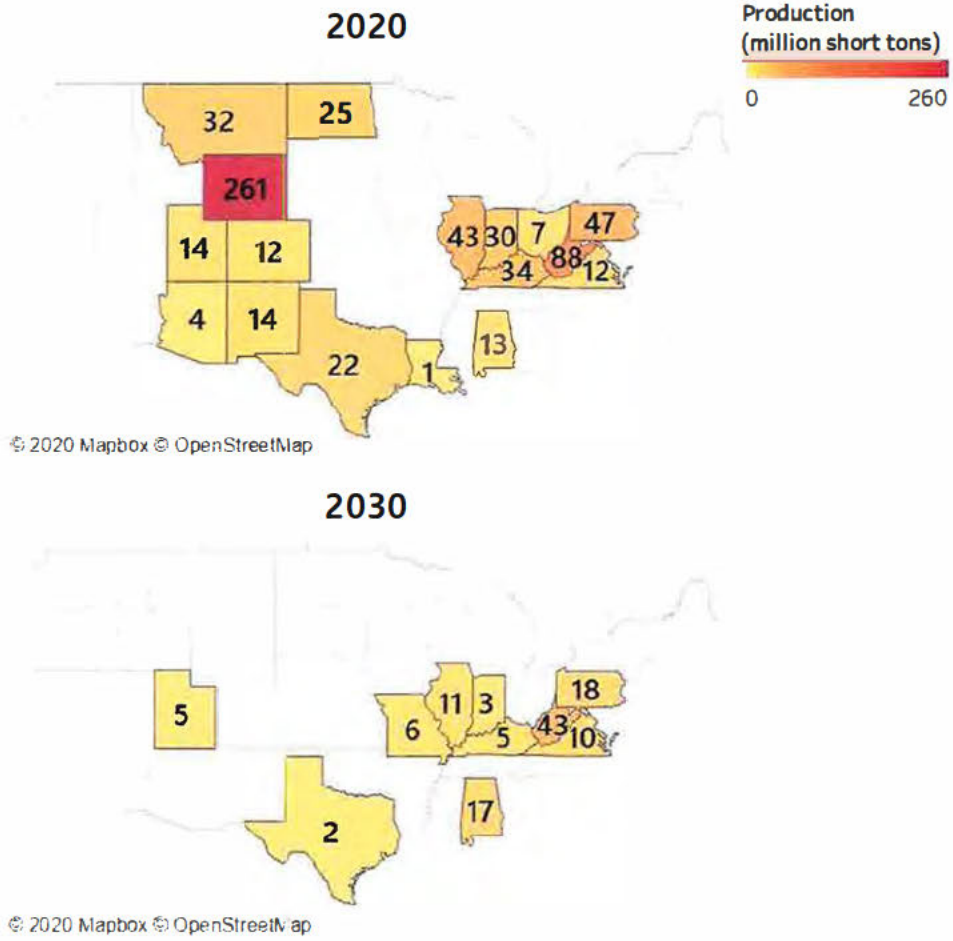
Summary of this section

Thermal coal consumption and production ceases by 2030.

- Over 700 coal mines close and some 500 coal-fired power plants are retired.
- The majority of coal plants retire at >30 years age, with just 8% retiring at <20 years and 50% retiring at >50 years.

In all net-zero pathways most of the nearly 700 mines close by 2030, impacting all coal-producing regions.





Note: We assume that the US continues to produce coal post-2030 to meet domestic industrial and coking demand as well as projected exports consistent with the EIA 2020 AEO Reference case projections. We assume that coal imports are trivial. In 2030 for the E+ scenario, we assume that continued coal production to meet export demand occurs in states that have historically produced coal for export; we use the 2019 historical state origin of exports to spatially allocate future production.

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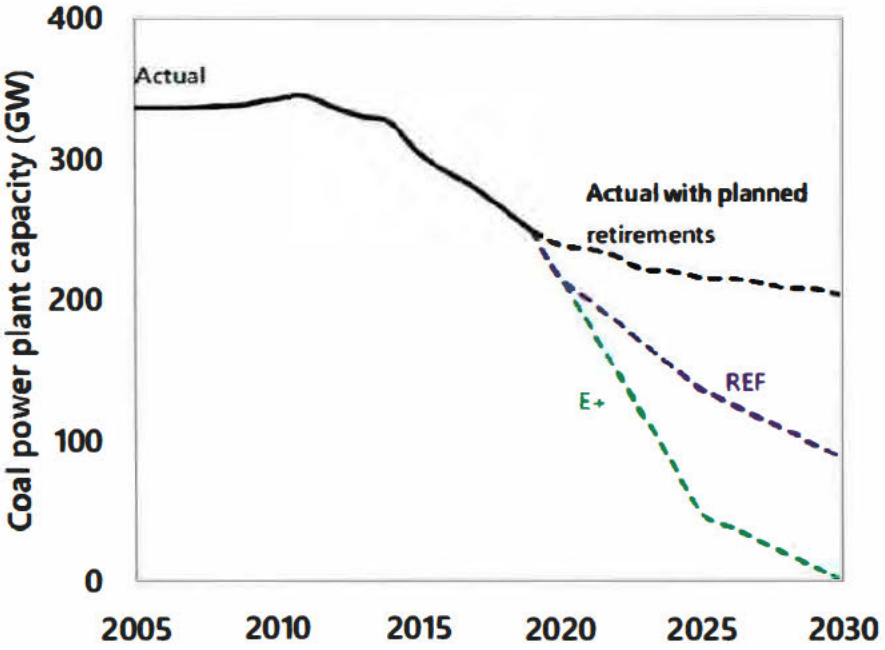
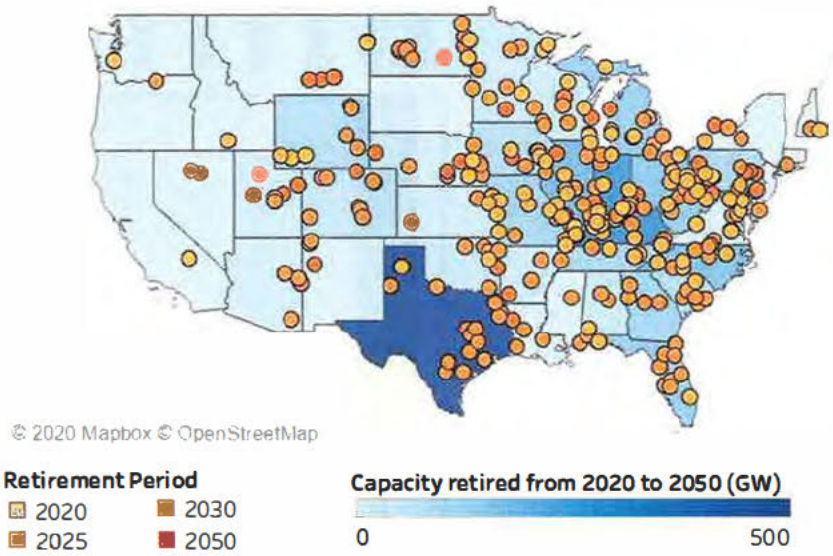
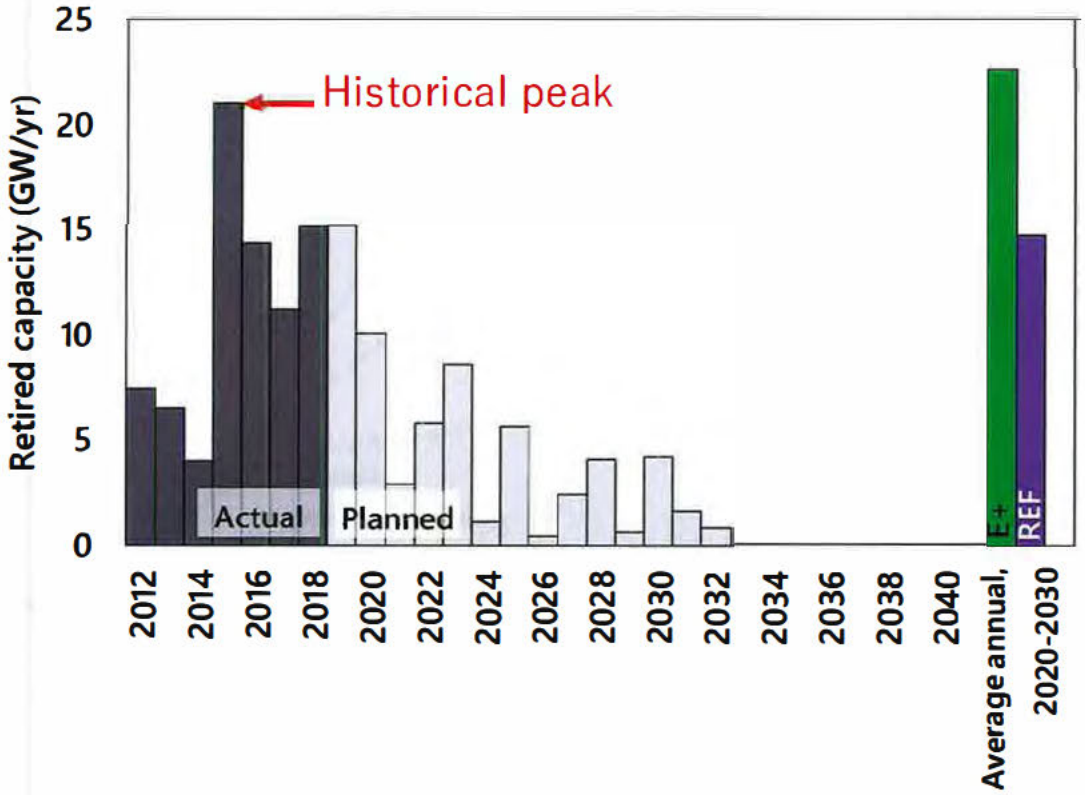
All coal power plants (500+) close by 2030.



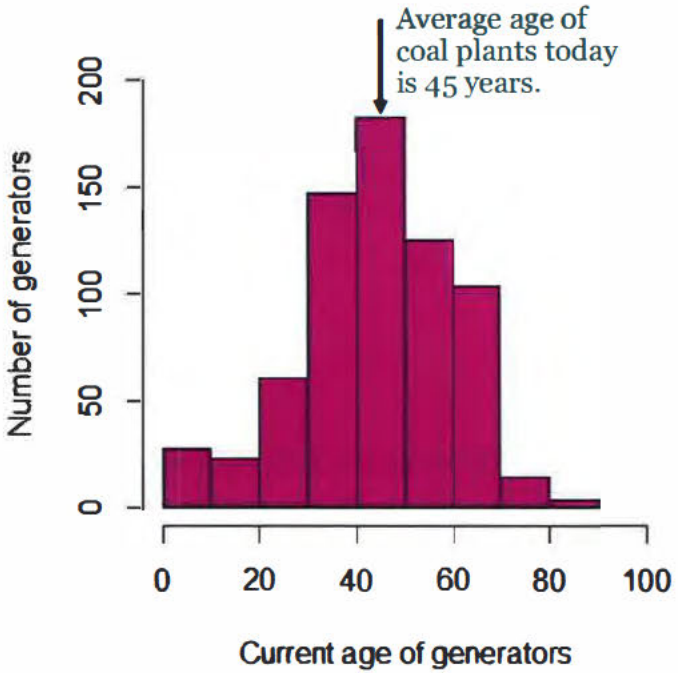
Retirement period of coal generators in E+ scenario



Average annual coal retirements in all net-zero scenarios is close to the historical peak rate observed in 2015.

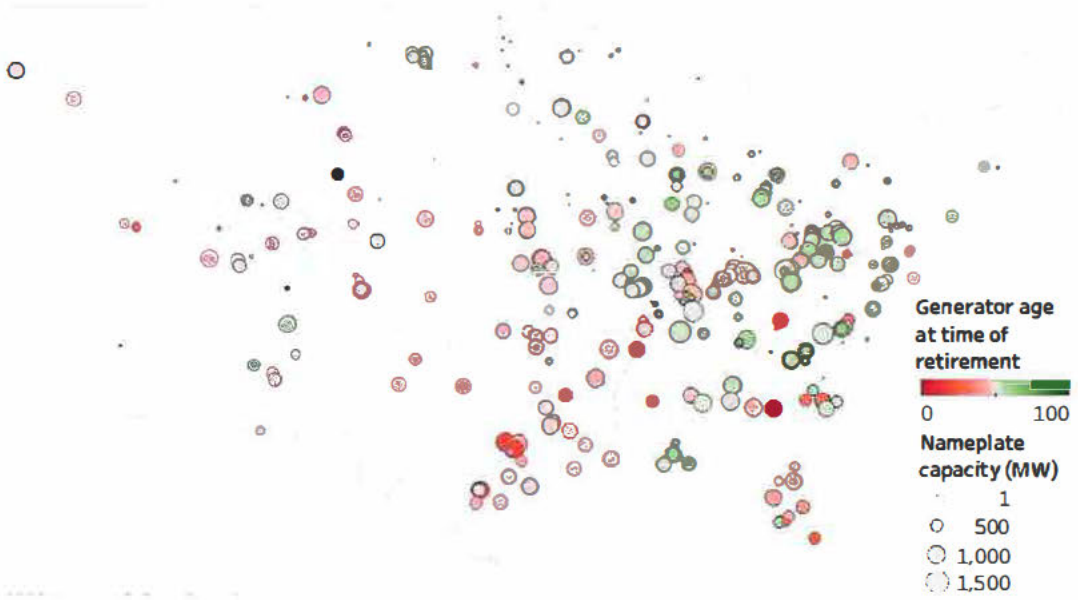


The U.S. coal fleet is old. Half of plants retire 50+ years old in the 2020's. Less than 8% (23 GW) retire before reaching 20 years.



Retirement of coal generators for E+ scenario

Generators indicated in red retire prior to the typical 50-year lifespan of coal generators, consistent with Grubert (2020).



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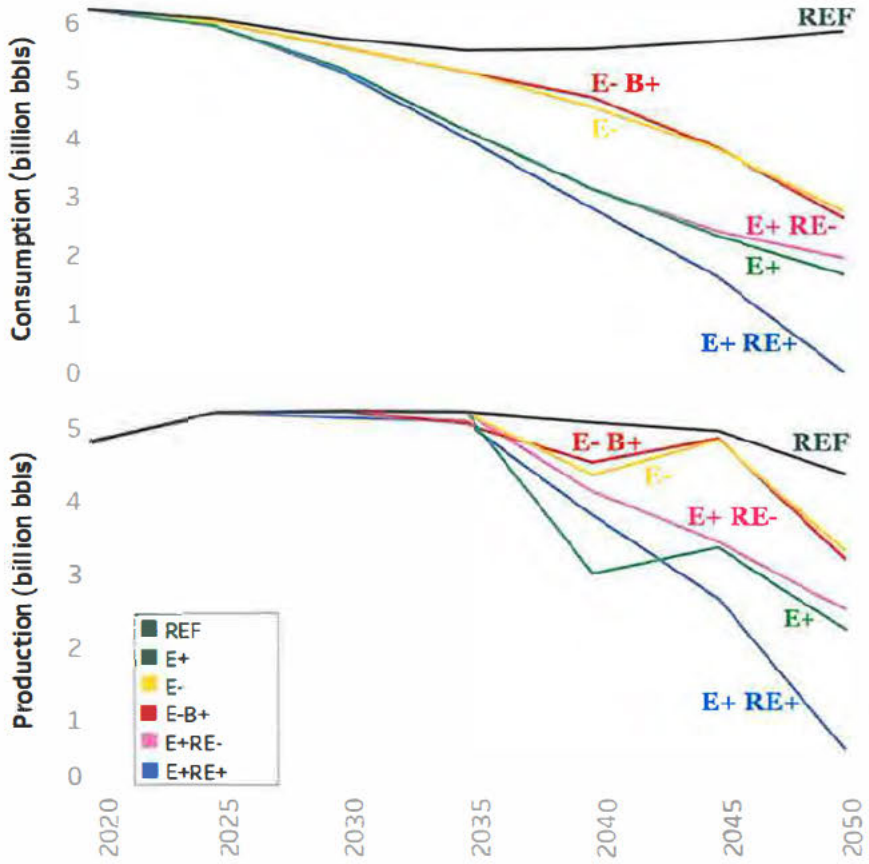
Oil



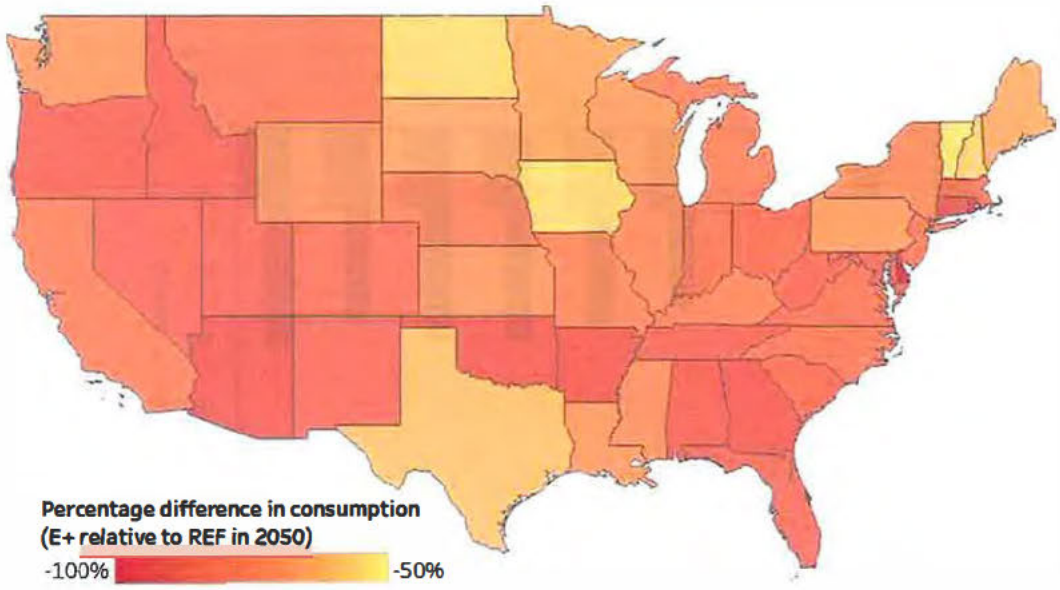
Summary of this section

- Oil production declines 25% to 85% across the suite of NZA scenarios, relative to the reference scenario
- Consumption declines 55% to 100% by 2050 in net-zero scenarios.
- Exports remain in line with AEO projections to 2050.
- Oil production to 2050 in net-zero scenarios exceeds current proven reserves, but is less than projected reserves based on recent growth rates.

Oil consumption declines 55% to 100% by 2050 for net-zero scenarios relative to REF; production declines 25% to 85%.



Change in oil consumption in E+ case relative to REF



Note: Production projections assume US produces at a rate consistent with or lower than the 2019 EIA AEO Reference case and continues to export oil at rate consistent with the AEO projection. As domestic consumption declines, an increasing share of demand is met through domestic production and a decreasing share of oil is imported. Starting around 2035, domestic demand has fallen to the point that oil imports are no longer needed, and with further demand declines thereafter, US production also declines.

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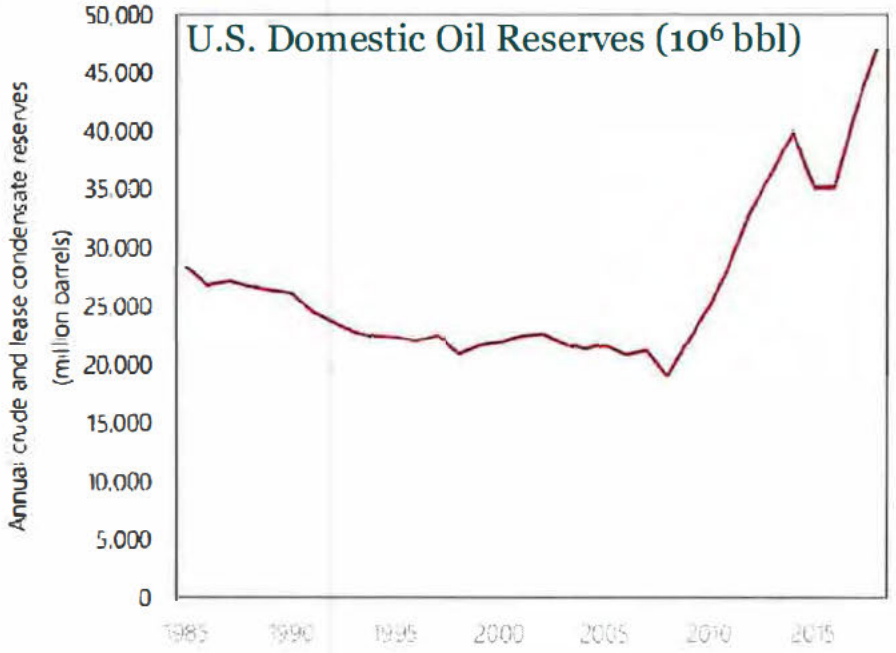
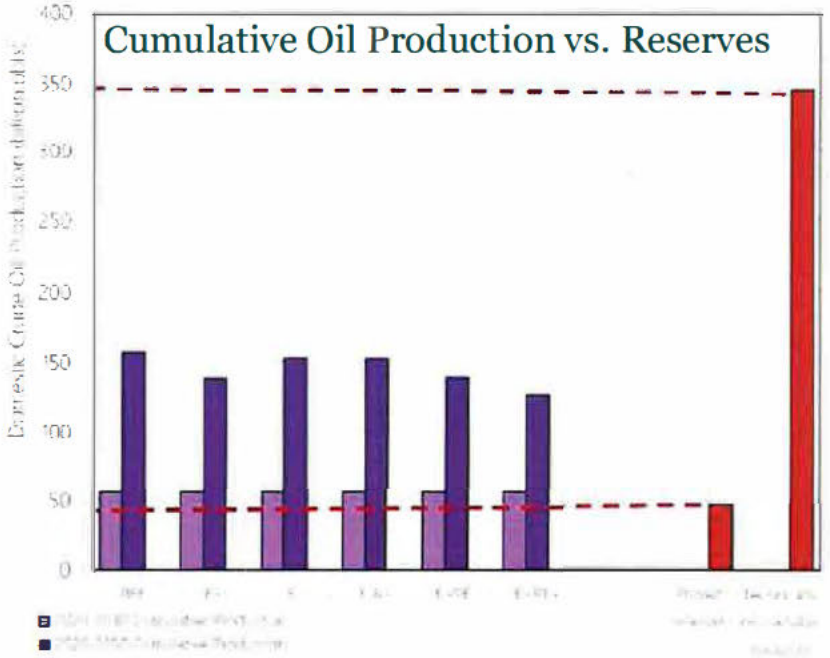
Cumulative oil production through 2030 exceeds current proved reserves, but continued additions could risk stranding assets.





- Cumulative oil production to 2050 in REF and net-zero scenarios exceeds current proven reserves, indicating that all current reserves can be produced in these scenarios.
- If recent annual rates of reserve addition persist, however, proved reserves could surpass projected cumulative oil production and result in some stranded assets.

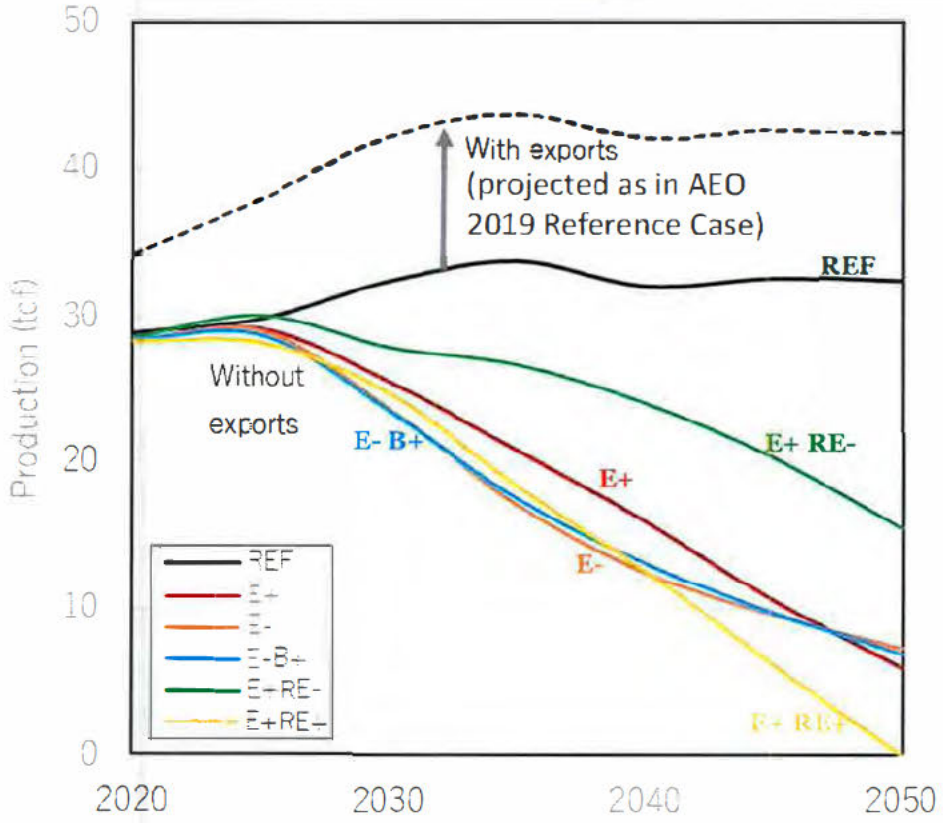
Natural Gas



Summary of this section

- Natural gas production declines between 25% and 85% across the suite of NZA scenarios, relative to the reference scenario
- Consumption declines 50% to 100% by 2050 in net-zero scenarios.
- Exports remain in line with AEO projections to 2050.
- Significant declines in revenues for producers and bringing forward some $25 billion in remediation costs.
- Gas production in to 2050 in net-zero scenarios exceeds current proven reserves, but is less than projected reserves based on historical growth rates.
- Significant stranded asset risks for transmission and distribution networks.

Natural gas consumption declines 50% to 100% by 2050 in net-zero scenarios relative to REF.



- Over ½ million gas wells close in 2020's; plug and abandonment costs are estimated to be ~$25 billion.

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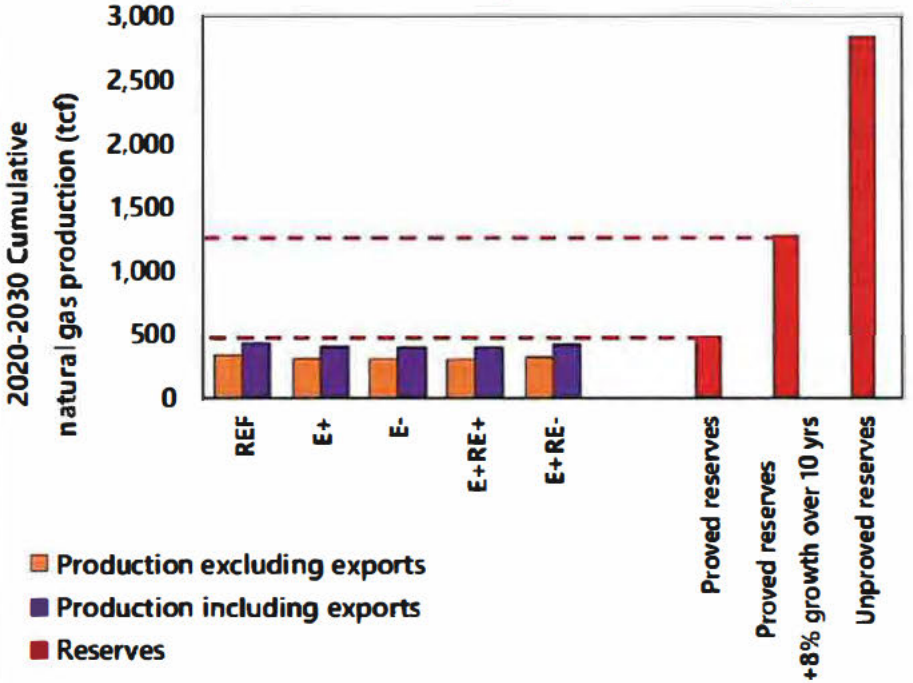
EIA reserves estimates.

Natural gas production through 2030 is less than current proved reserves, but continued reserve additions could risk stranding assets.

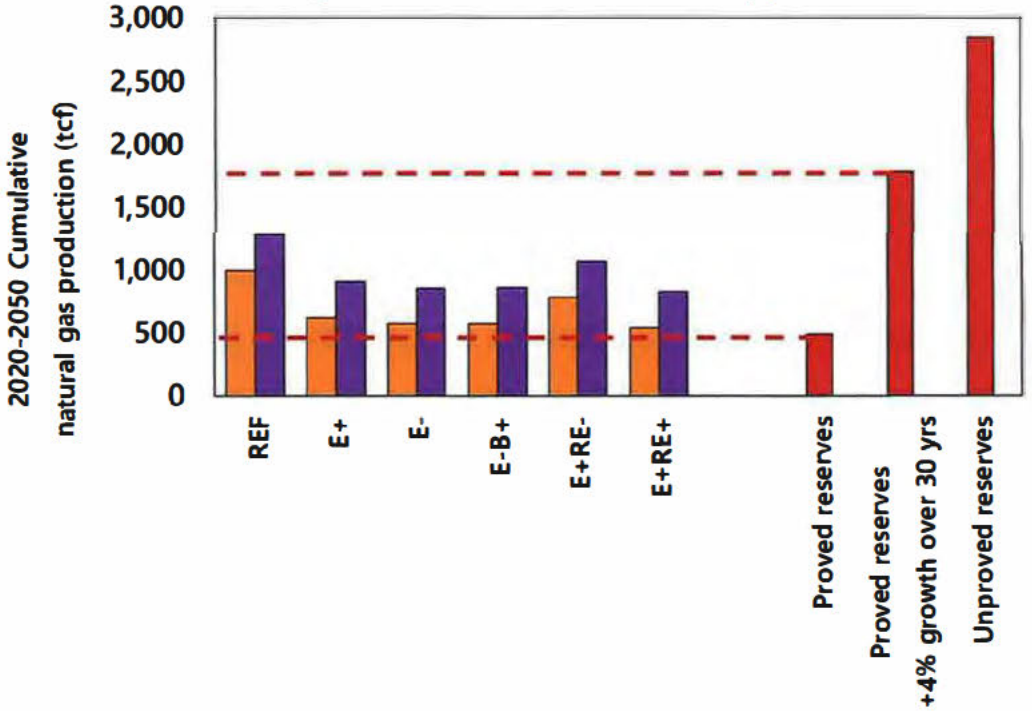
2020-2030 Near-term production and reserves

Cumulative gas production to 2030 in E+ is less than today's proved reserves, even without reserve additions at short-term historical growth rates (8%/year).



2020-2050 Long-term production and reserves

Cumulative gas production to 2050 in E+ exceeds today's reserves, but is less than reserves if reserves grow at long-term historical rate (4%/year).



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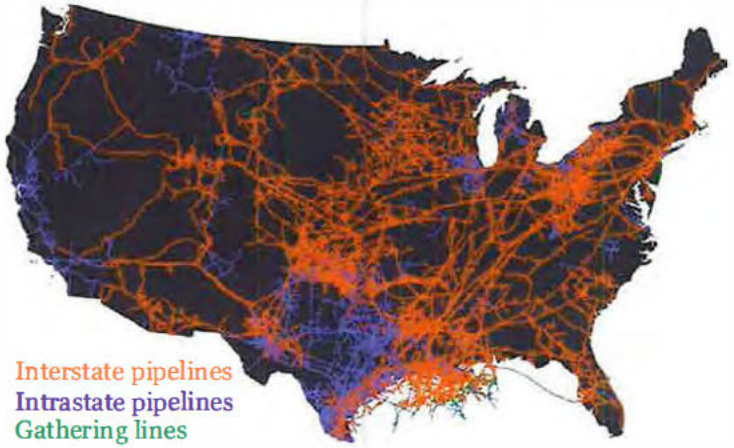
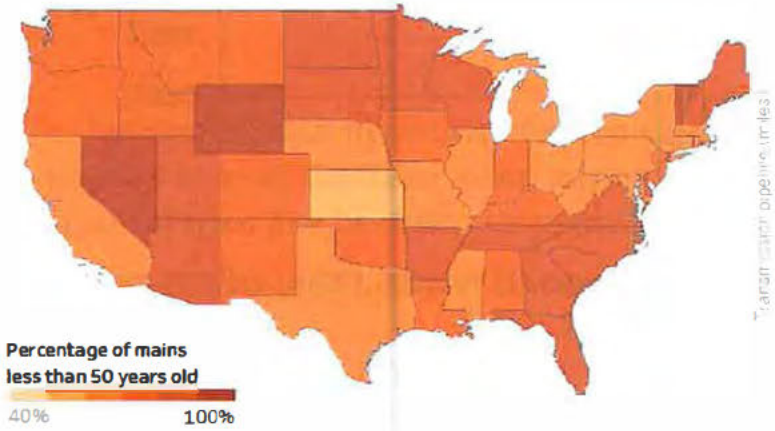
Declines in natural gas consumption will impact gas transmission and distribution infrastructure.



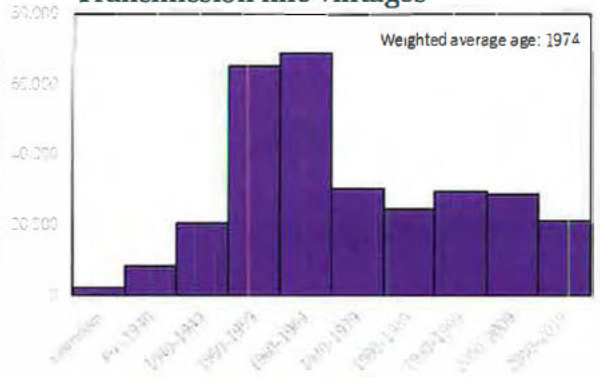
The existing gas pipeline network is vast:

- 20,000 miles of gathering lines (50% >30 years old)
- 300,000 miles of transmission lines (70% >30 years old)
- 1,300,000 miles of distribution mains (50% > 30 years old)
- 70,000,000 service lines

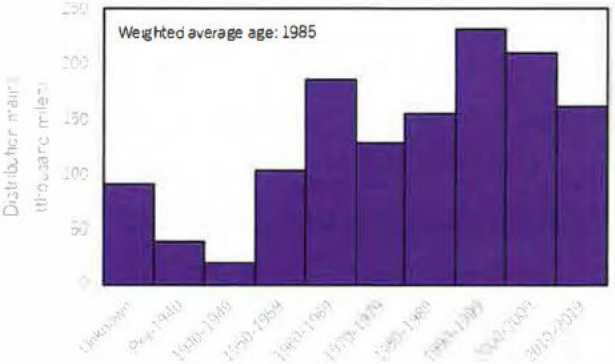


The transmission network is aging, but some distribution system replacements have accompanied the shale gas boom:

Transmission line vintages



Distribution main vintages



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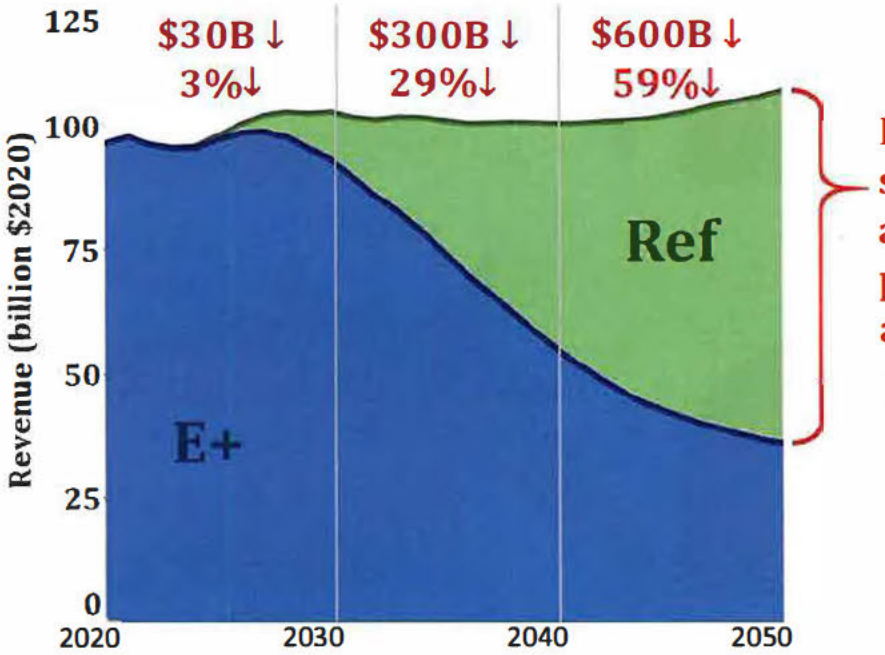
As gas use falls, volumetric revenues will decline, prompting need to review rate design and network asset valuations

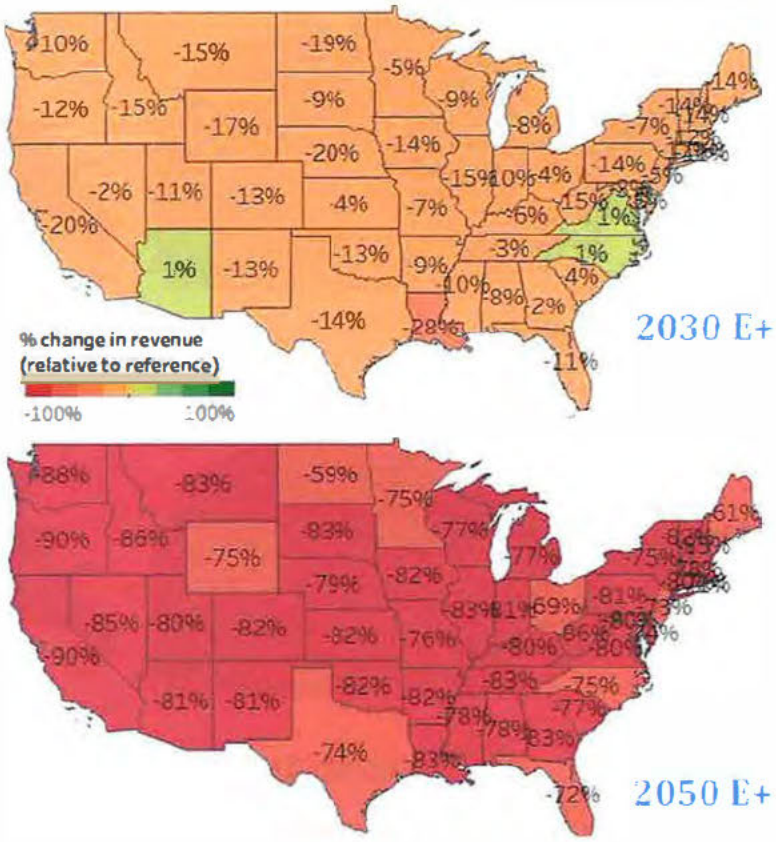


Decline in natural gas market revenue (E+ v. REF) assuming volumetric rates



Reduced spending, assuming gas prices constant across scenarios

*Revenue includes dollars through commodity cost



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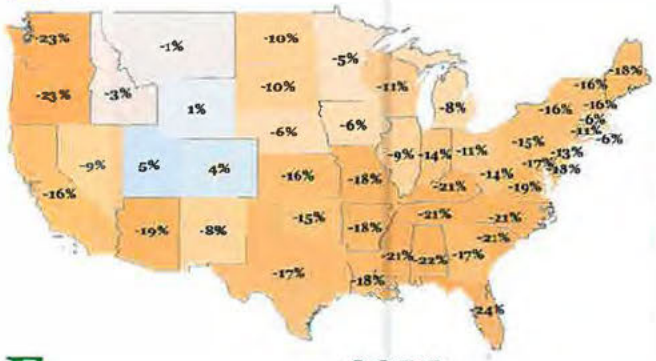
Declining customer base over time will challenge cost recovery and raise equity concerns.

Percent reduction in number of gas-fired residential heaters from 2020

E+



2030

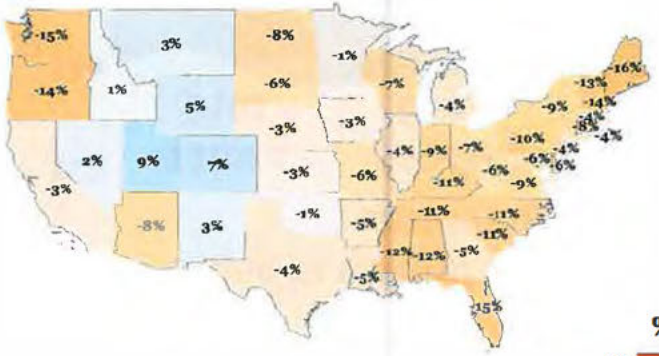


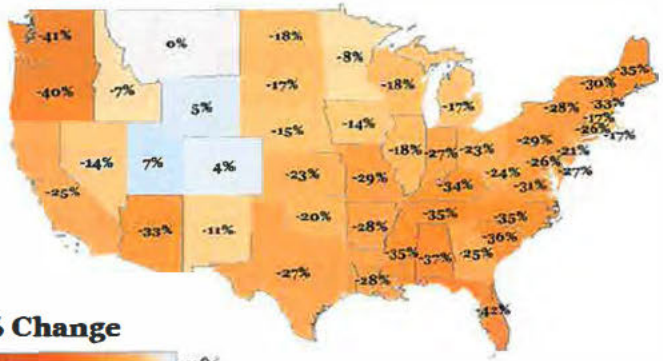
2040



2050

E-







% Change

-100% 5%

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Employment impacts



Summary of this section

- A model was built to assess supply-side employment, wages, and workforce development requirements in energy-system transitions. (Energy efficiency, vehicle and appliance related employment is not modeled in this report.)
- To support modeled net-zero transitions, the supply-side energy workforce expands by upwards of 30% in the 2020s and nearly triples by 2050. Today ~1.5% of the labor force is directly employed in supply-side energy-related jobs. By 2050, this grows to 2-4.5% across different net-zero scenarios.
- In the 2020s, net-zero pathways support an annual average of ~3 million supply-side energy jobs, a net increase of ~0.5-1 million jobs relative to a business-as-usual scenario (REF).
- Net job losses in fossil fuel sectors across the transition are more than offset (in aggregate) by increases in low carbon sectors, especially solar, wind, and electric-grid sectors. Construction comprises an increasing portion and mining (i.e., oil, gas, coal upstream activities) comprises a declining portion of jobs over time.
- Changes in labor productivity have a large influence on employment outcomes and more broadly on the energy transition as whole. This modeling explicitly considers impacts of productivity changes on future employment.
- An annual average of ~$180-190 billion in wages are generated in the 2020s, for a net increase of $30-40 billion over REF. Supply-side energy sector employment generates ~2% of total U.S. wages, rising to ~2-5% by mid-century.
- A number of modifiable sociotechnical factors influence the spatial distribution of labor. With assumptions used here, all states see energy-related employment grow as a share of the total state labor force except for a few with very high shares of the current labor force employed in upstream fossil fuel industries (e.g., WY, ND). In some states with high resource quality (e.g., NE, MT, IA), energy industries grow to become dominant employers.
- There will be an increasing demand for workers with a diversity of education, experience, and training backgrounds.

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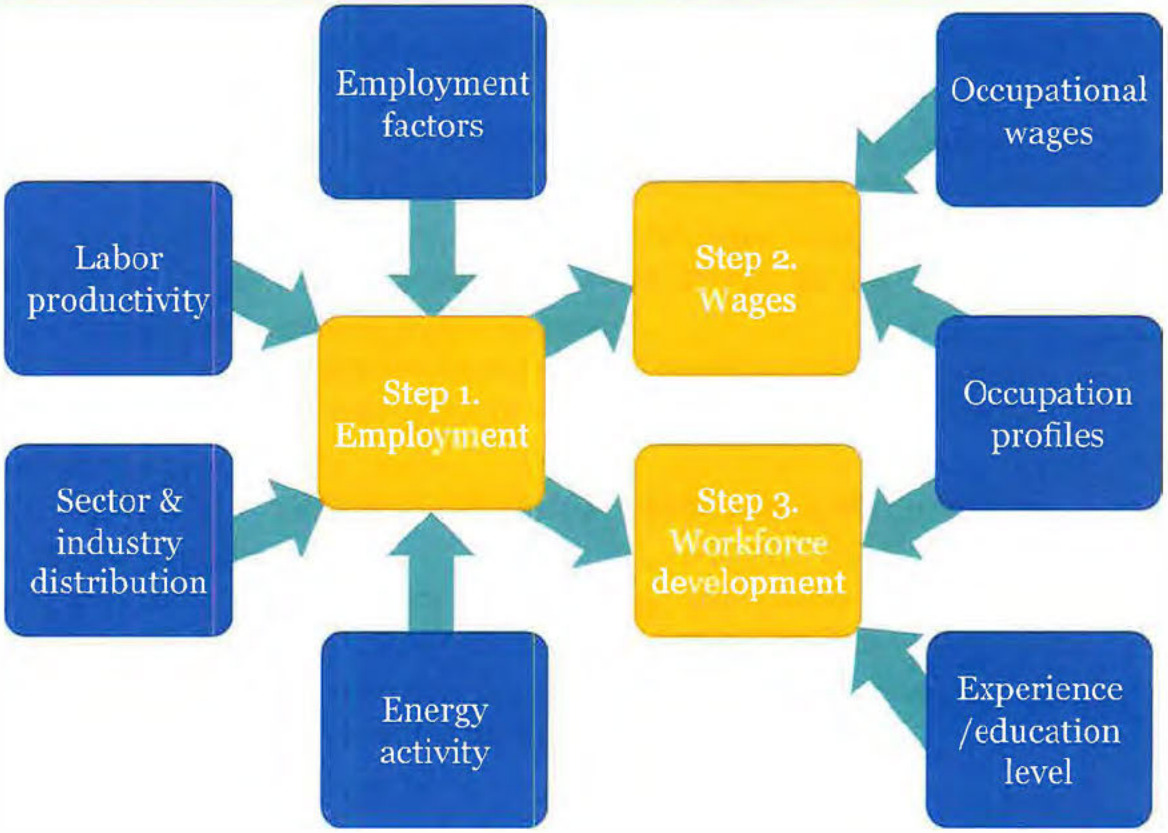
Decarbonization Employment & EneRgy Systems model (DEERS)

Labor model assesses supply-side employment, wages, and workforce development requirements associated with energy system transitions.

- Pairs with output of economy-wide or spatially downscaled macro-energy system modeling.
- Architecture largely derived based on current data of economic accounts and energy activity.
- Models the distribution of labor impacts across 50 states, 9 economic sectors, 9 resource supply chains, 50 industries, and 1000+ occupations.
- Includes time-variant factors, such as labor productivity and wage inflation, relevant for long-term planning.
- Used to evaluate policy and planning decisions, such as just transition funds, workforce development needs, domestic manufacturing, oil and gas exports, and facility siting.



Note: In this analysis, we focus on supply-side resource supply chains (i.e., biomass, CO_2, coal, electric power grid, natural gas, nuclear, oil, solar, wind). We do not model employment related to energy efficiency, electric vehicles, or consumer electronics/appliances.

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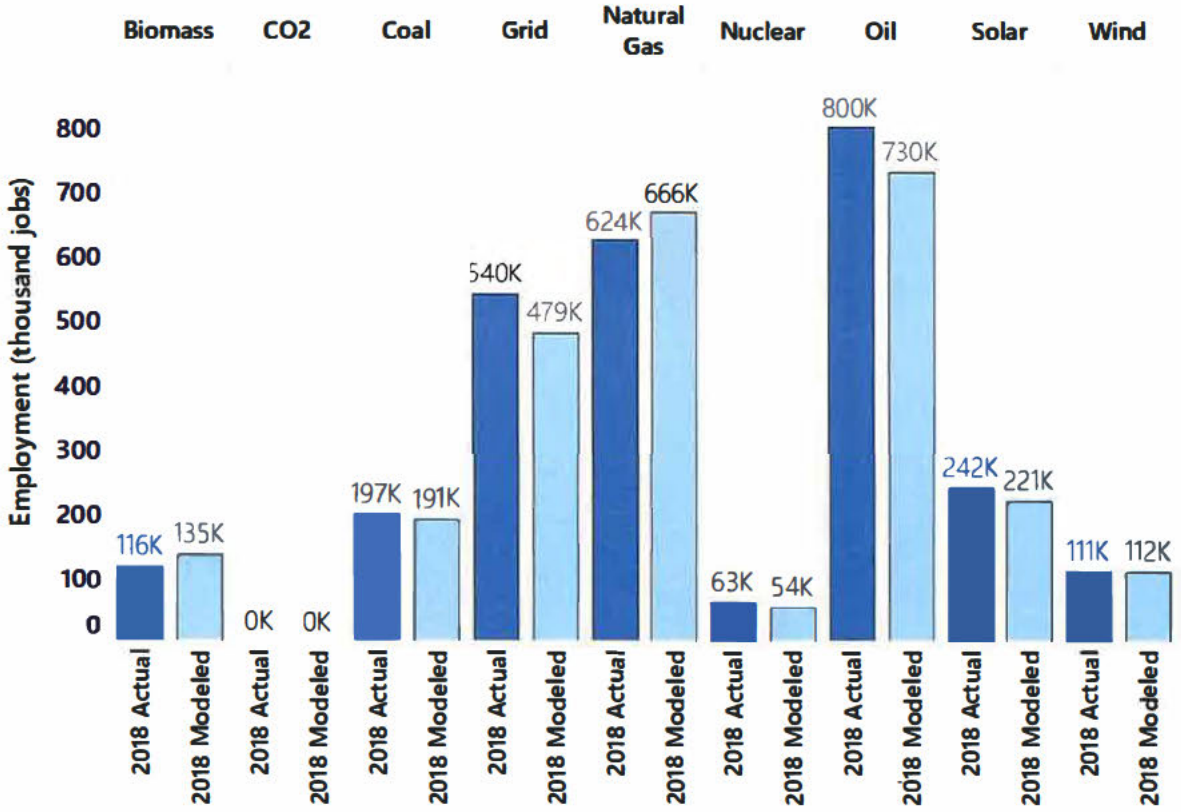
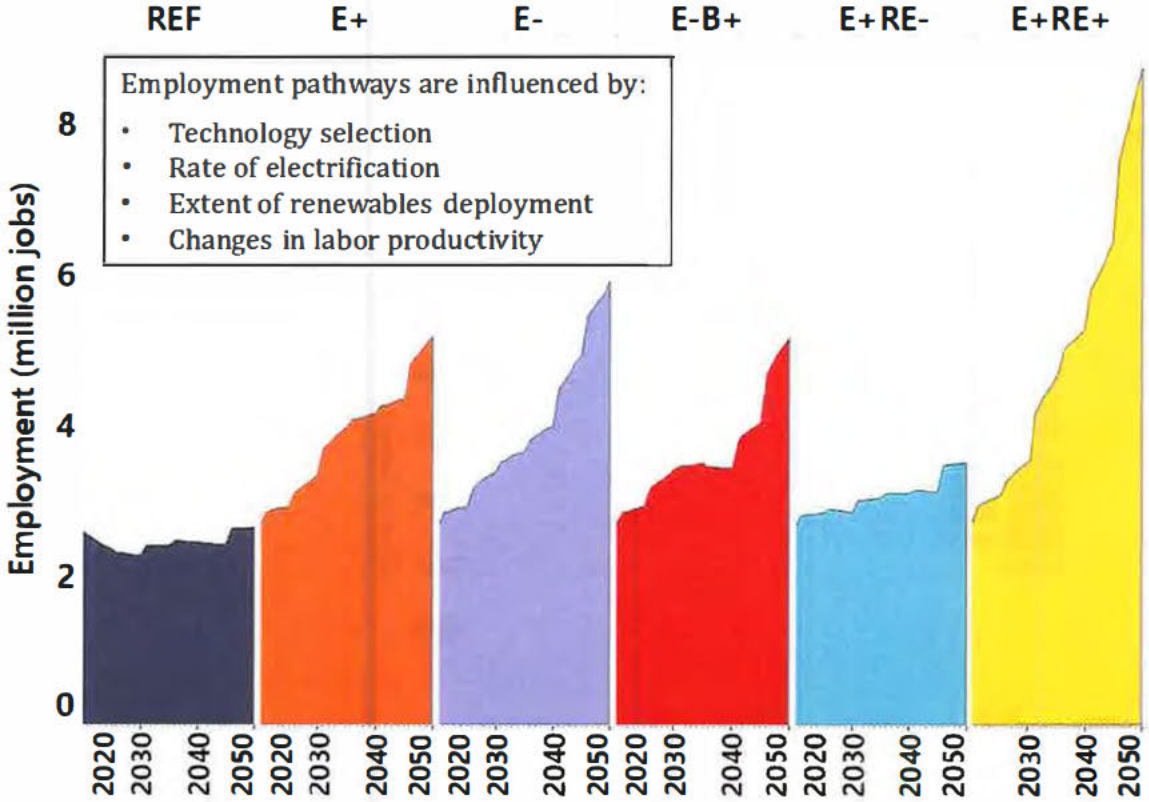
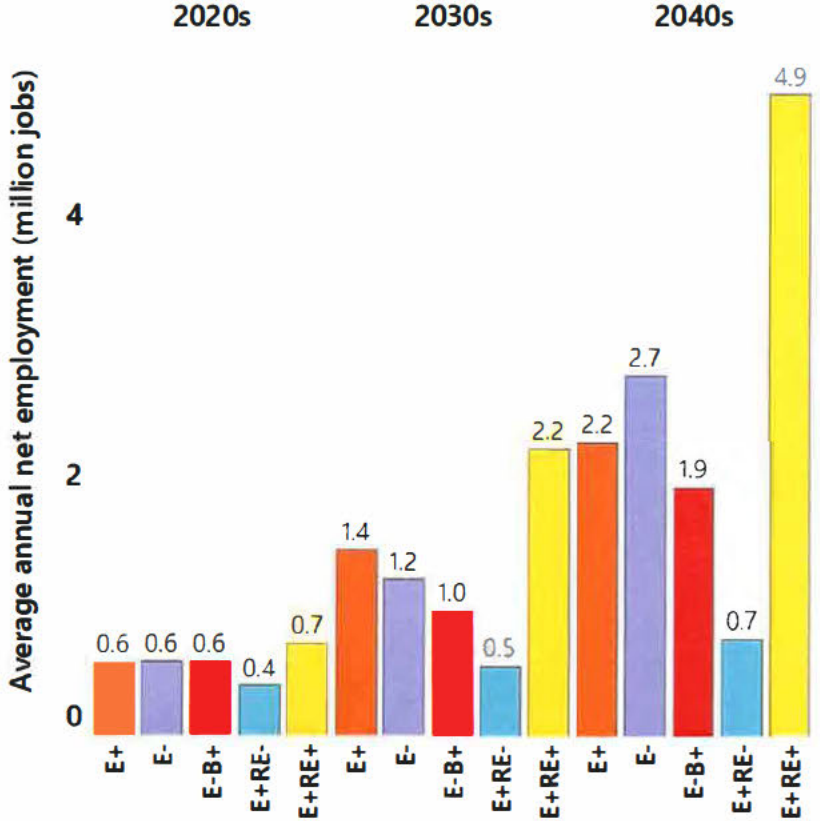
Calibration: DEERS model results using 2018 inputs match up well with actual 2018 employment across resource sectors.



~3 million energy-supply jobs annually in the 2020s in net-zero scenarios, a net increase of ~0.5 – 1 million jobs over REF.





Note: Equilibrium impact on net economy-wide employment is not modeled.

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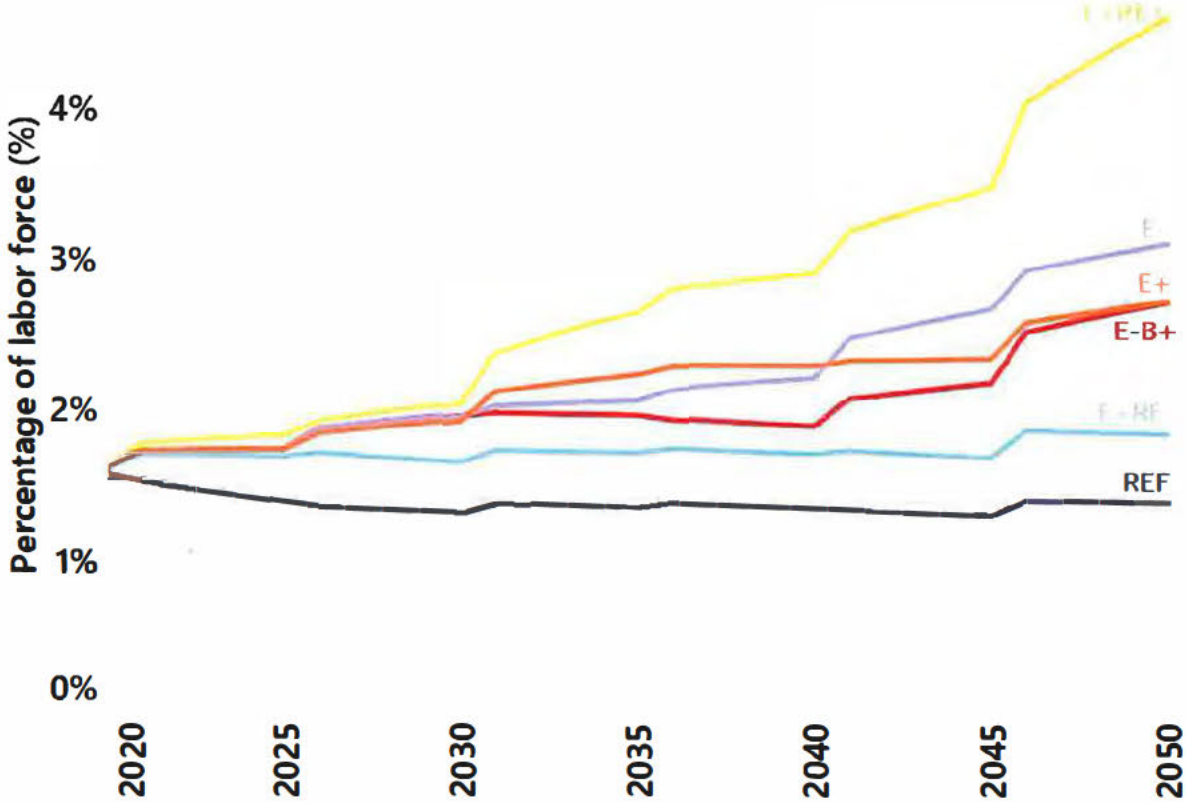
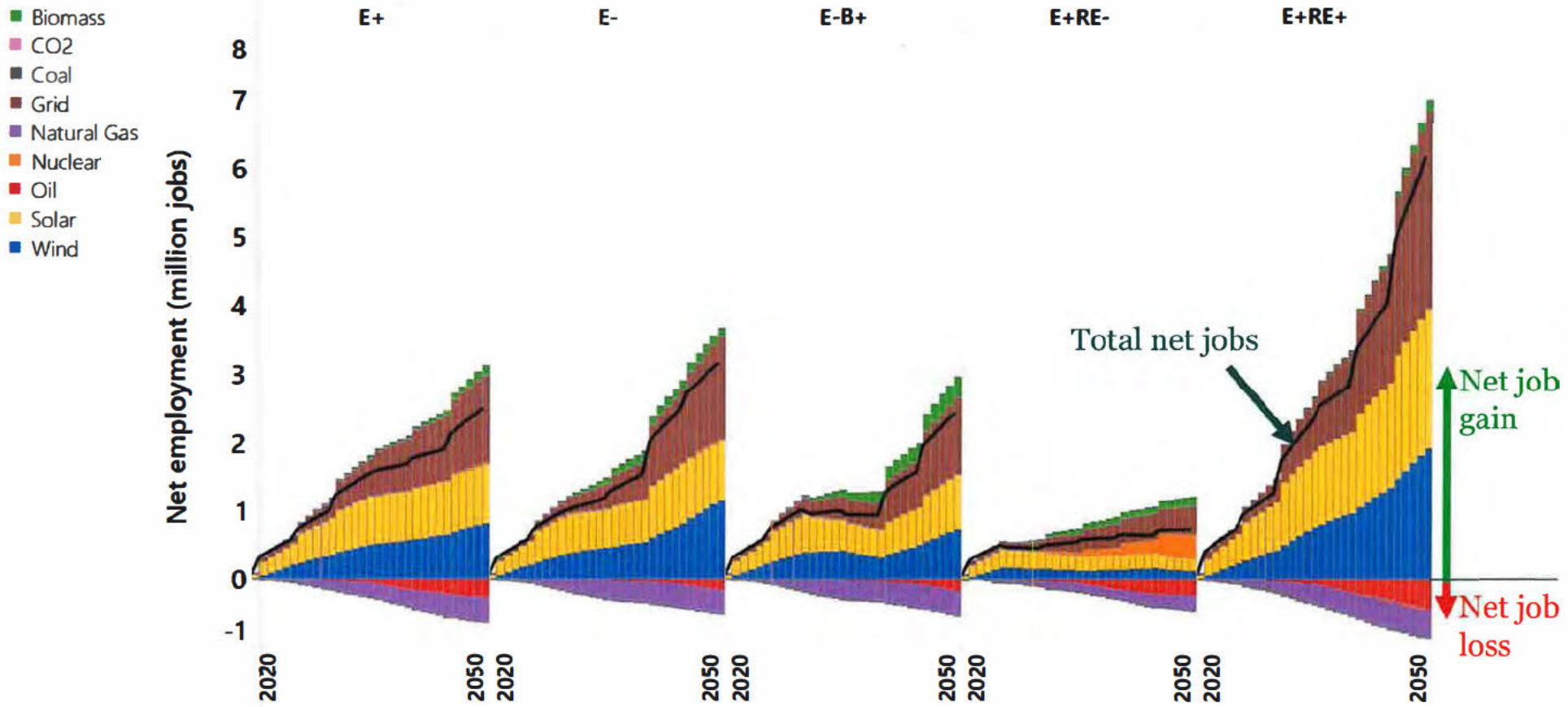
1.5% of the U.S. labor force is directly employed in energy-supply today; this may increase by 2050 to 2 to 4.5%.



Note: Equilibrium impact on net economy-wide employment is not modeled.

Net job losses in fossil fuel sectors in near- and long-term are more than offset (in aggregate) by increases in low carbon sectors



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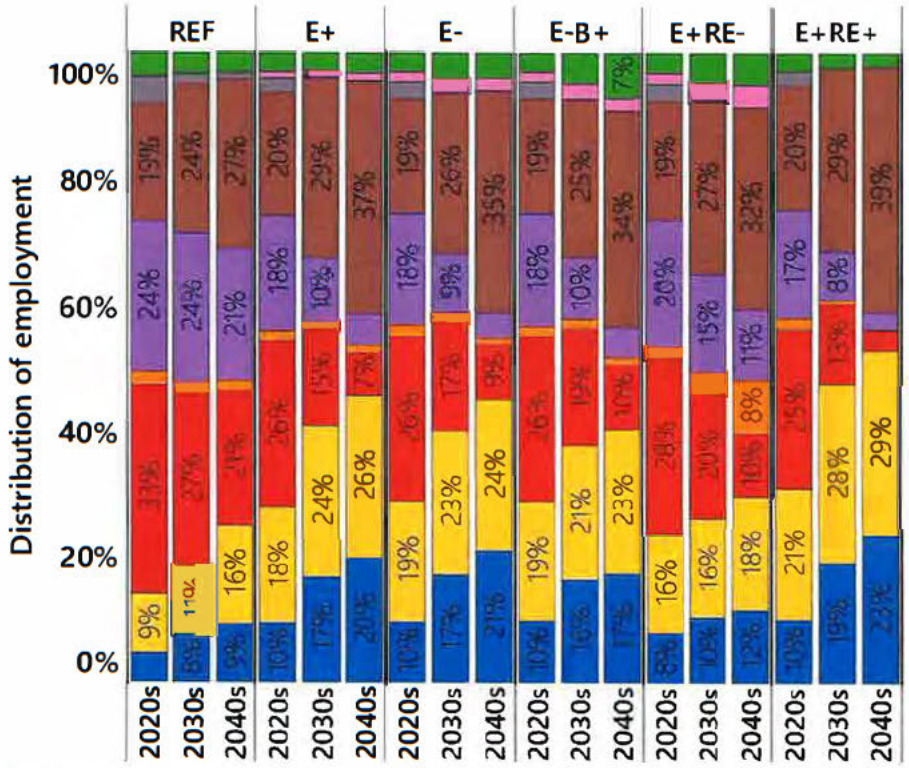
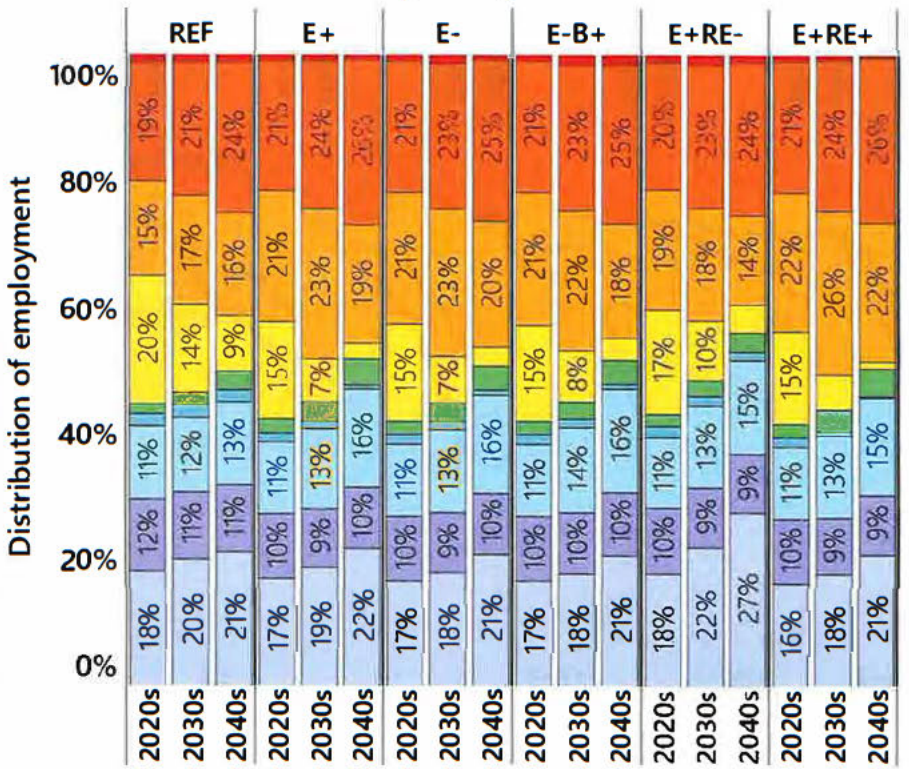
Solar and wind dominate energy-related jobs. Construction sector share increases over time, while mining (upstream fossil) declines.

Distribution of jobs by resource sector



Resource sector
- Biomass
- CO2
- Coal
- Grid
- Natural Gas
- Nuclear
- Oil
- Solar
- Wind

Distribution of jobs by economic sector



Economic sector
- agriculture
- construction
- manufacturing
- mining
- other
- pipeline
- professional
- trade
- utilities

Note: Mining includes upstream coal, oil, and gas activities.

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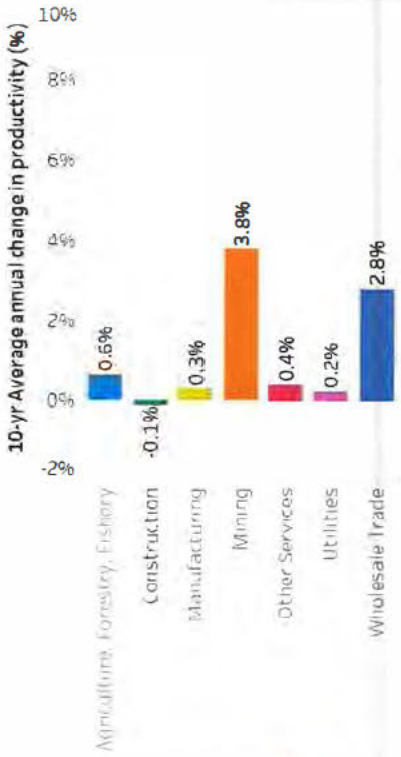
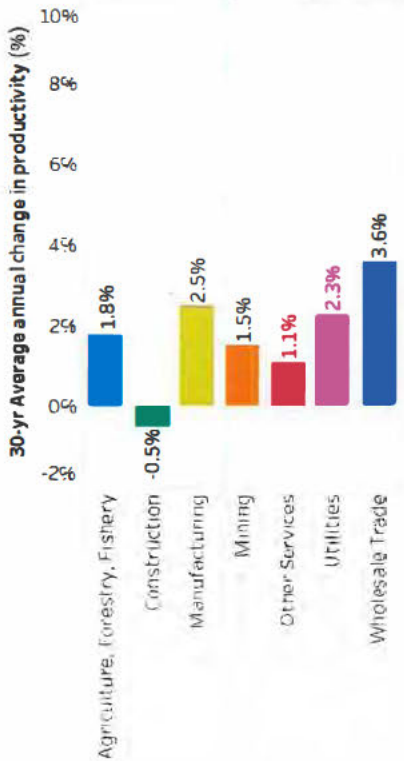
Changes in labor productivity have a large influence on employment outcomes and more broadly the energy transition as whole.

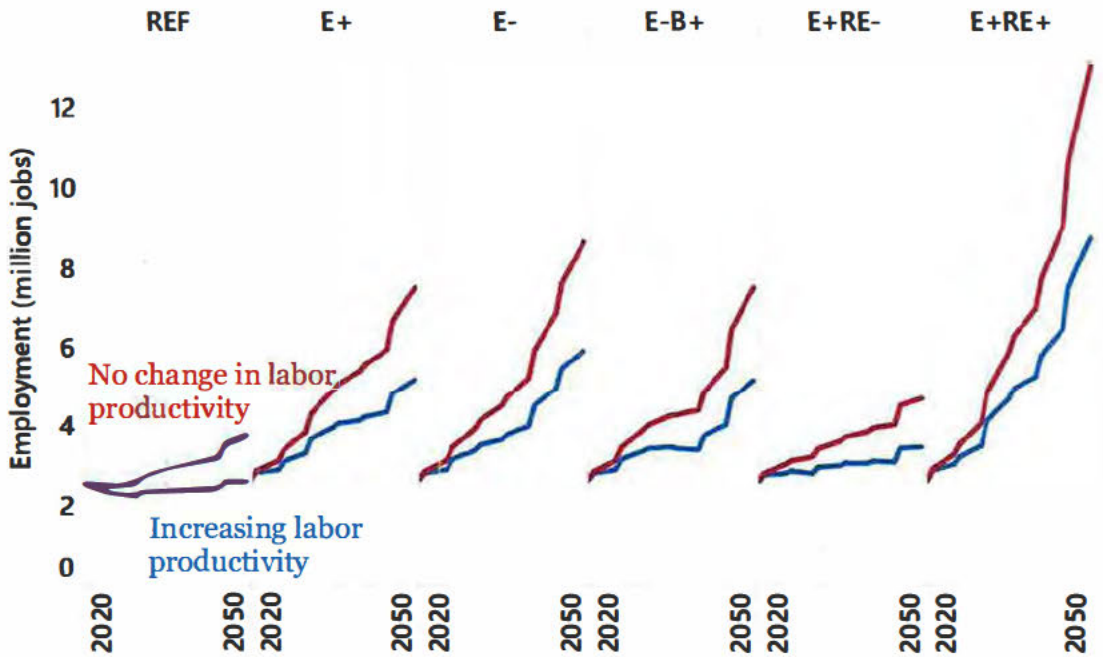
Historical changes in labor productivity

Short-term



Long-term





Note: Other employment modeling results shown in this report correspond to the results with increasing labor productivity shown on this slide.

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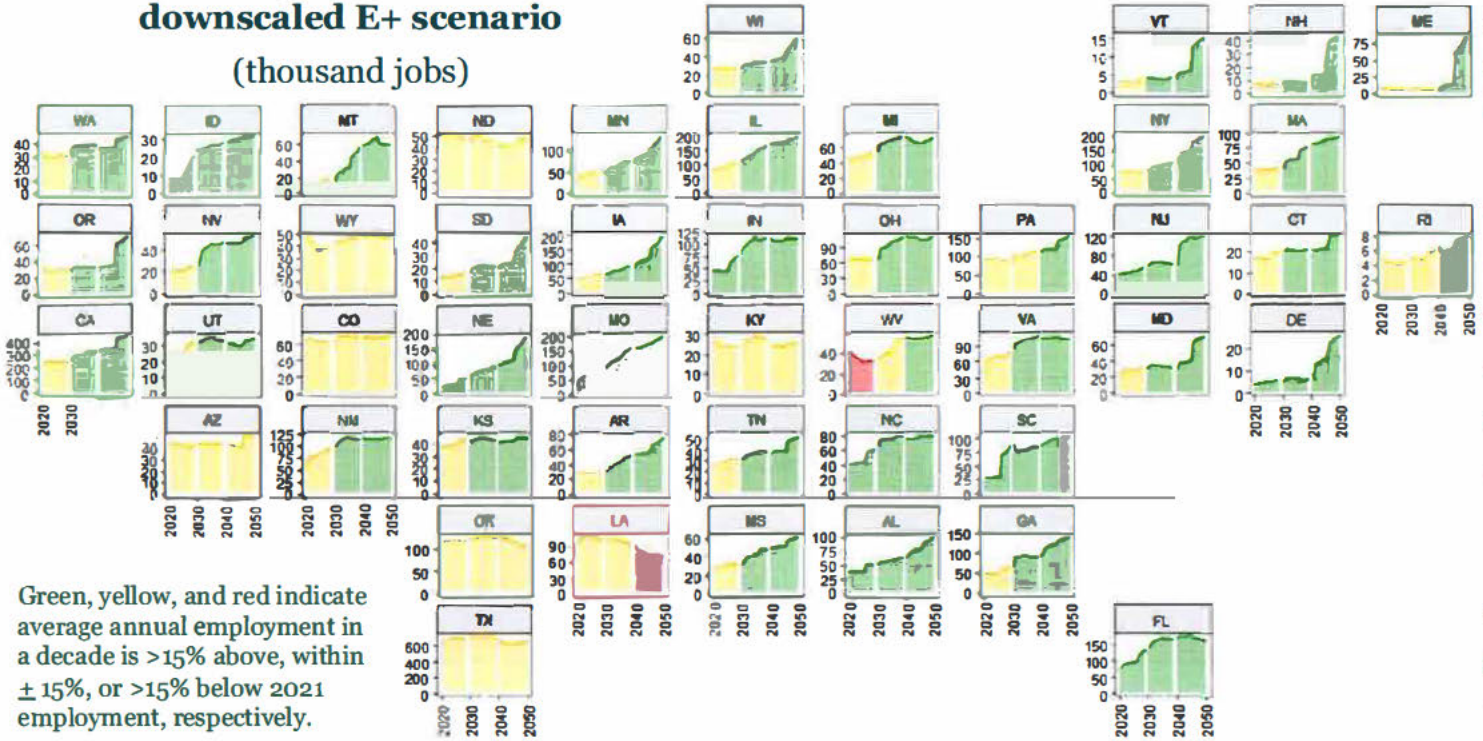
Modifiable socio-technical factors influence spatial distribution of employment. Below is one instantiation of the future (out of many).



Annual employment based on downscaled E+ scenario

(thousand jobs)



Green, yellow, and red indicate average annual employment in a decade is >15% above, within ± 15%, or >15% below 2021 employment, respectively.

Modifiable sociotechnical factors that influence the spatial distribution of employment:

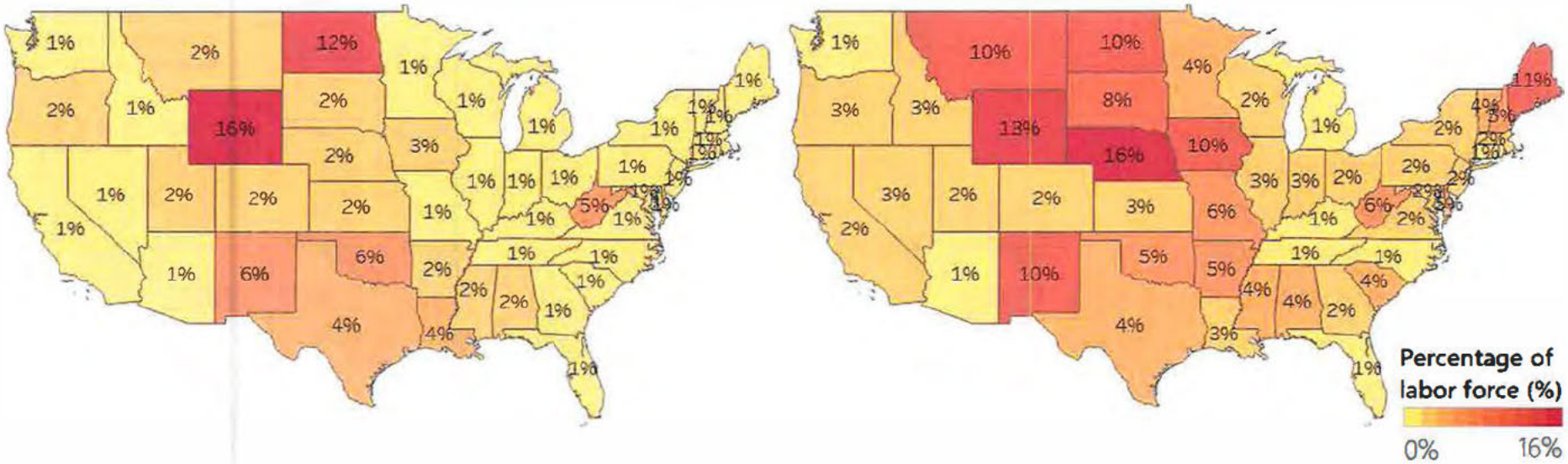
- Resource quality and availability
- Rate of electrification
- Technology selection
- Domestic manufacturing
- Siting constraints
- Oil and gas exports
- Political and policy processes and constraints

There are several degrees of freedom that can reduce transition risks and be leveraged for political bargaining.

Note: Spatial redistribution of solar and wind manufacturing facilities and increasing the domestic manufacturing share offer opportunities to ameliorate losses in fossil fuel extraction states. For assumptions used here in siting solar and wind manufacturing jobs, see this slide.

In most states, energy-related employment grows as a share of total employment through the transition period.

E+ scenario **2020** **2050**

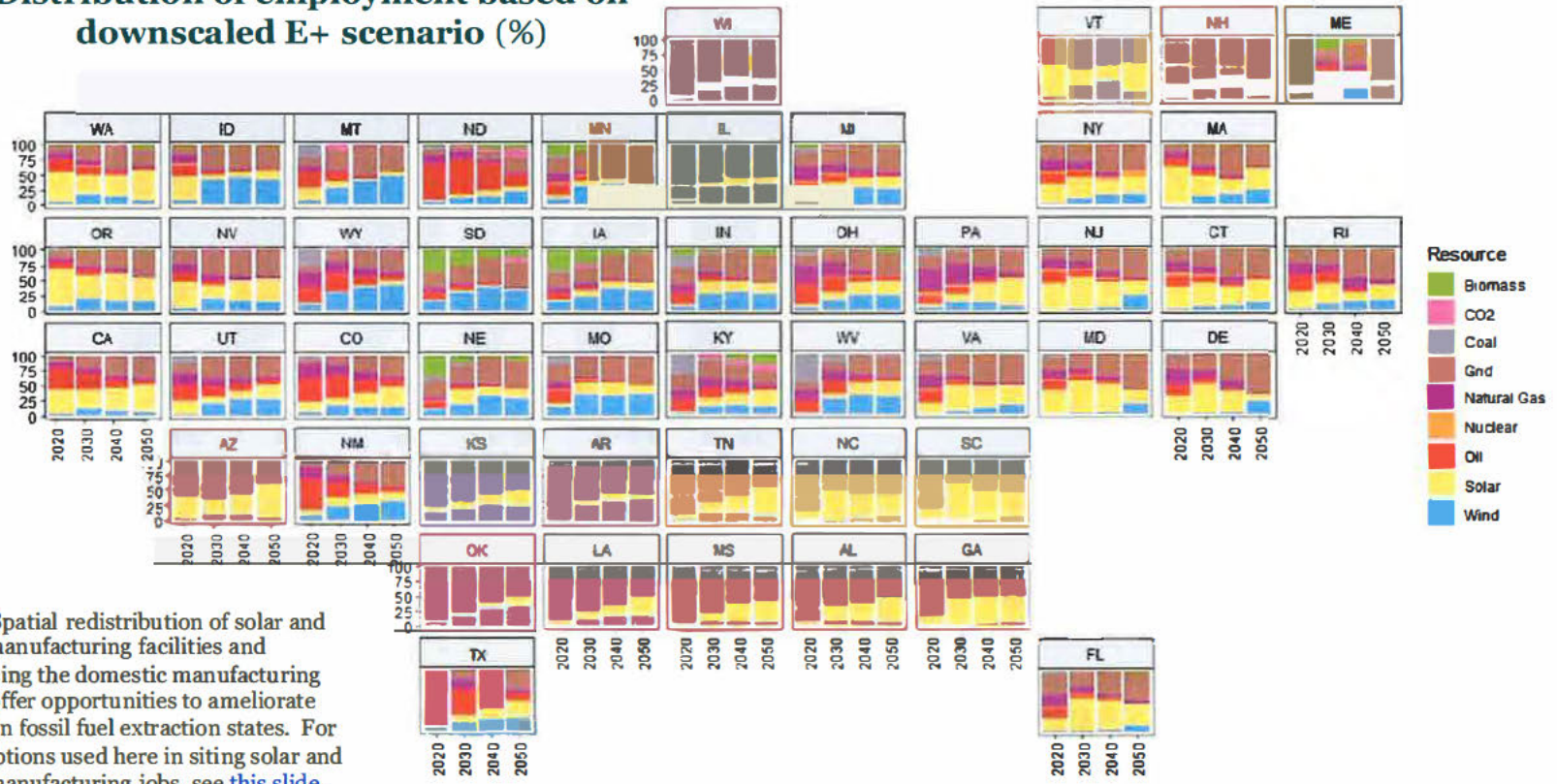


- In a few states with a very high share of the current labor force employed in upstream fossil fuel industries (e.g., WY and ND), energy-related employment decreases as a share of the total employment.
- In states with high renewable resource quality (e.g., NE, MT, and IA), energy industries grow to become major employers.

State-level distributions of employment by resource sector change dramatically over the transition.



Distribution of employment based on downscaled E+ scenario (%)



Note: Spatial redistribution of solar and wind manufacturing facilities and increasing the domestic manufacturing share offer opportunities to ameliorate losses in fossil fuel extraction states. For assumptions used here in siting solar and wind manufacturing jobs, see this slide.

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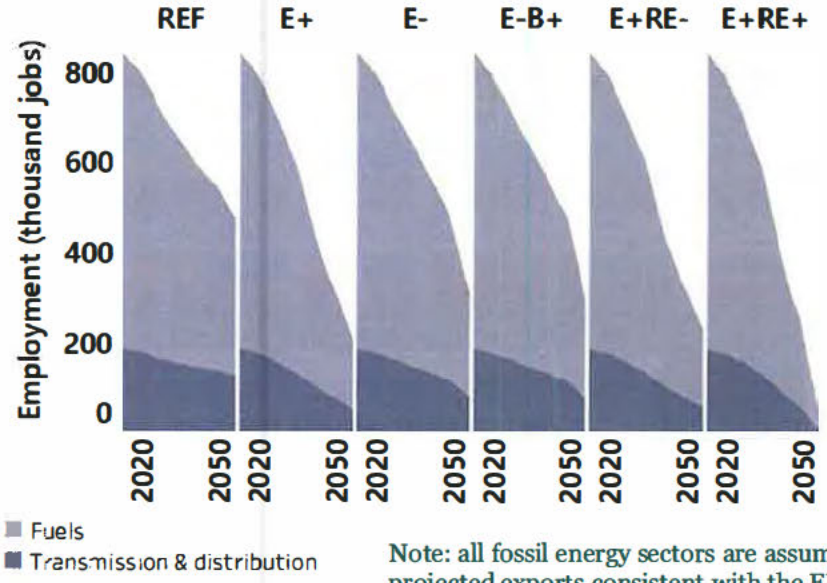
Oil sector today is largest resource sector, with nearly 1/3 of energy workforce. It supports over 800,000 jobs in model year 2021.

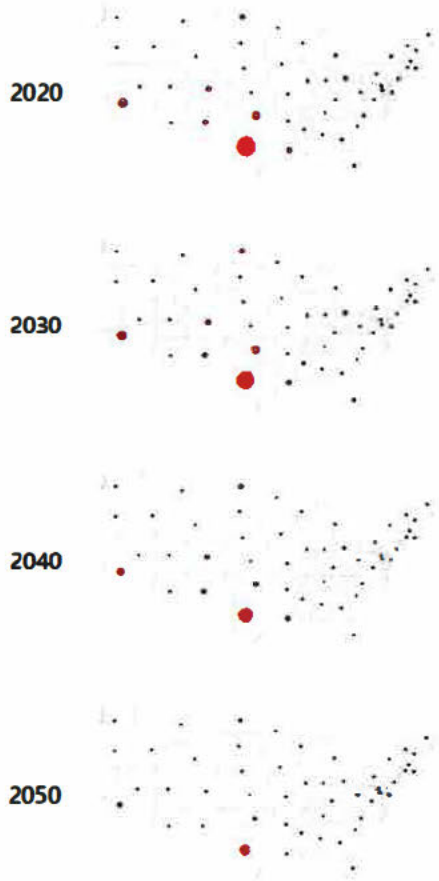
Employment declines in both REF and net-zero scenarios, and is influenced by the rate of electrification, extent of renewables deployment, and oil imports and exports. By 2050, employment in the REF scenario is approaching half that of 2020, and in the net-zero scenarios it declines by 60-95%.



Note: all fossil energy sectors are assume to continue domestic extraction to supply projected exports consistent with the EIA 2020 AEO Reference case projections.

Spatial distribution of supply chain employment for E+ scenario





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Natural gas sector is 2nd largest energy-employer, but upstream jobs have been rapidly declining for several years.

Natural gas sector supports 600,000 jobs associated with production (60%), transmission & distribution (30%), and power generation (10%) in model year 2021.



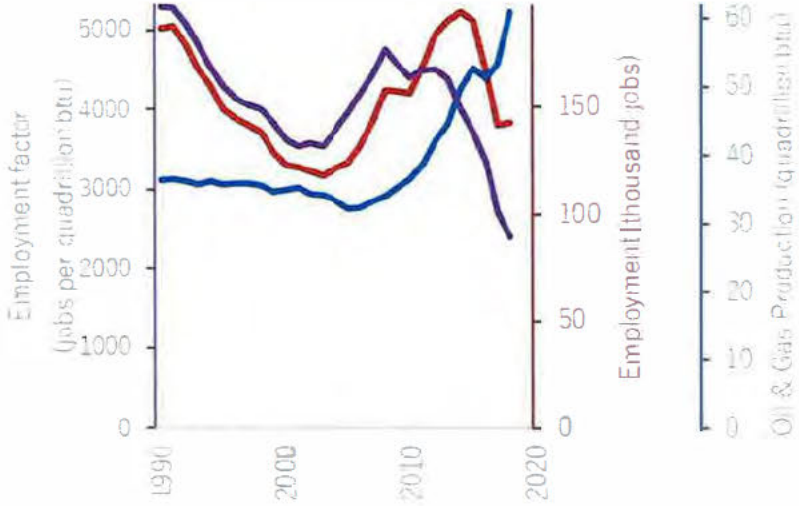
Source: NPR



Source: theint.net

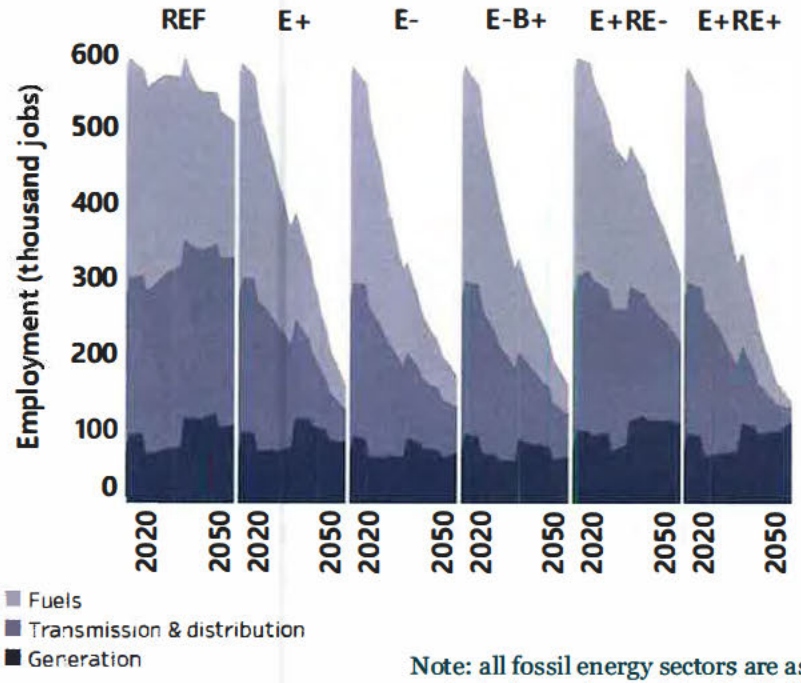
Natural gas extraction industry currently is a major employer in several counties, although part of the workforce is transient. During the peak of the shale gas boom, the natural gas industry in some rural communities comprised upwards of 60% of combined direct, indirect, and induced employment in one West Virginia county.

Employment in oil & gas extraction industry has been rapidly declining for years, and has accelerated during the COVID-19 pandemic.

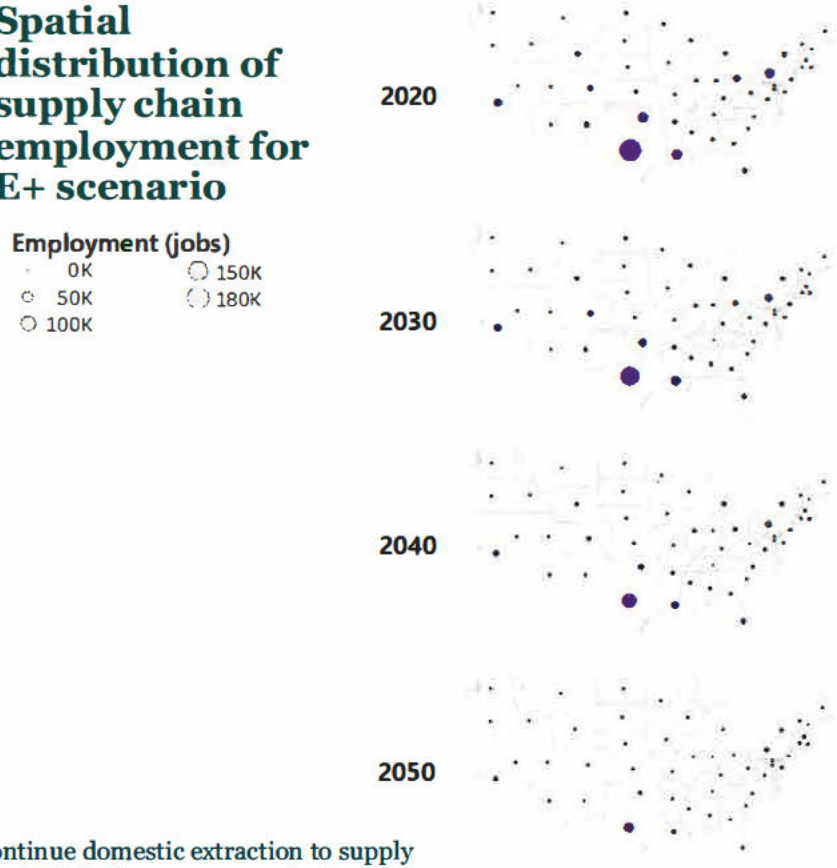


Natural gas-related employment declines, except for gas power generation. Impacts concentrated in Appalachia and Permian basin.

Natural gas employment decline is influenced by the rate of electrification, extent of renewables deployment, and natural gas exports.



Spatial distribution of supply chain employment for E+ scenario



Note: all fossil energy sectors are assume to continue domestic extraction to supply projected exports consistent with the EIA 2020 AEO Reference case projections.

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Coal mining jobs have been declining for 3 decades. Phasing out coal has greatest impact on resource-dependent rural labor markets.

At the national-scale, the coal sector is relatively small, representing 5% of the energy workforce in 2021. For model year 2021, supports 150,000 jobs associated with production (40%), transport (20%), and power generation (40%).

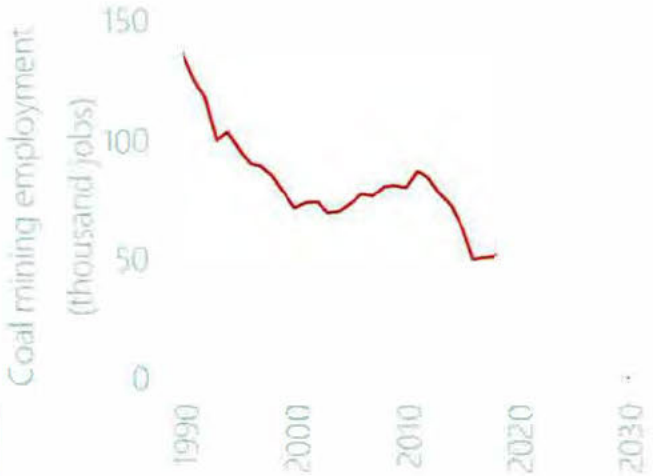


Source: Johnson Group

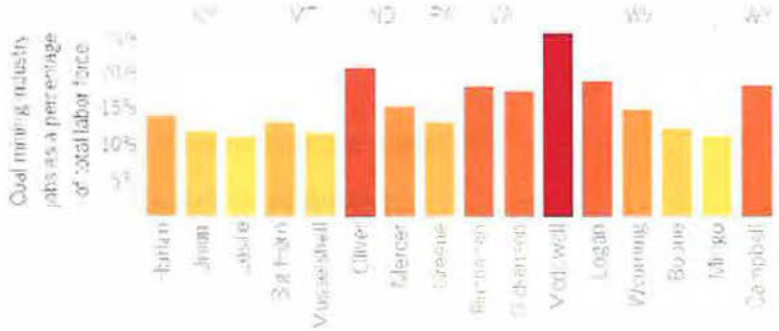


Source: power-technology.com

Over past three decades, employment in coal mining industry has declined dramatically (62%). Average decline rate of 3%/yr (3,000 jobs/yr) and peak decline rate in 2016 of 21%/yr (13,000 jobs/yr).



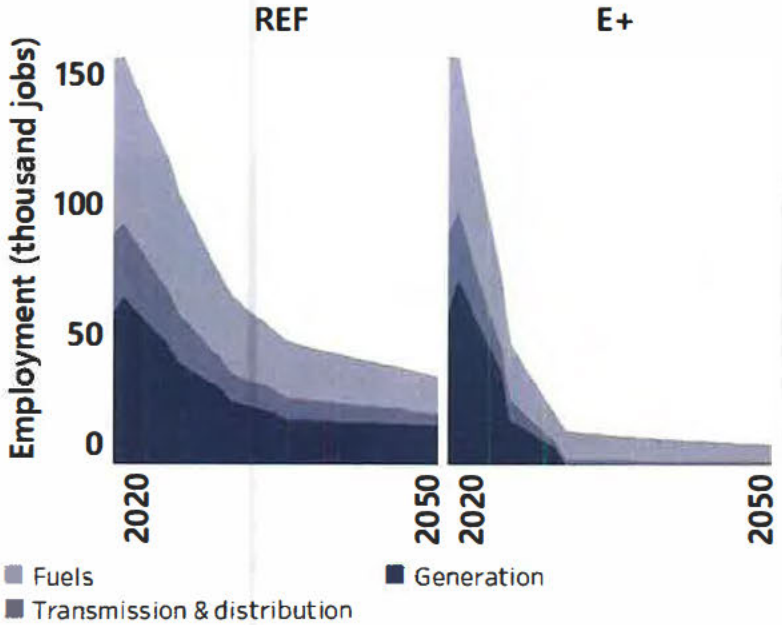
Coal mining industry currently is a major employer in several counties. The coal sector represents 5% or greater of labor force in 35 counties. This includes only jobs within the mining industry, not indirect and induced employment.



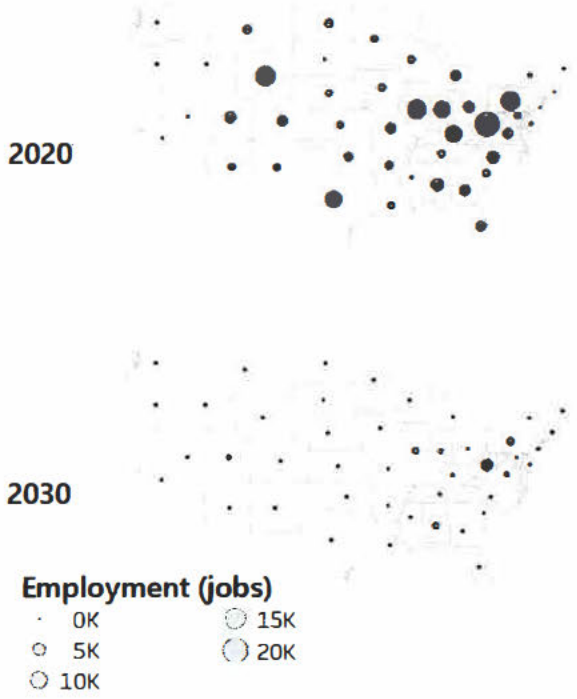
Coal mining jobs continue to decline at similar to recent historical rate. Impacts are concentrated in Appalachia & Powder River Basin.

Eliminating coal by 2030 implies an annual decline rate of 14,000 jobs/yr, compared to a decline rate of 8,000 jobs/yr in the reference scenario over the first decade

(6,000 jobs/yr mining/upstream, 2,000 jobs/yr transportation, 7,000 jobs/yr power generation)



Job losses concentrated in mining regions.



Note: all fossil energy sectors are assume to continue domestic extraction to supply projected exports consistent with the EIA 2020 AEO Reference case projections.

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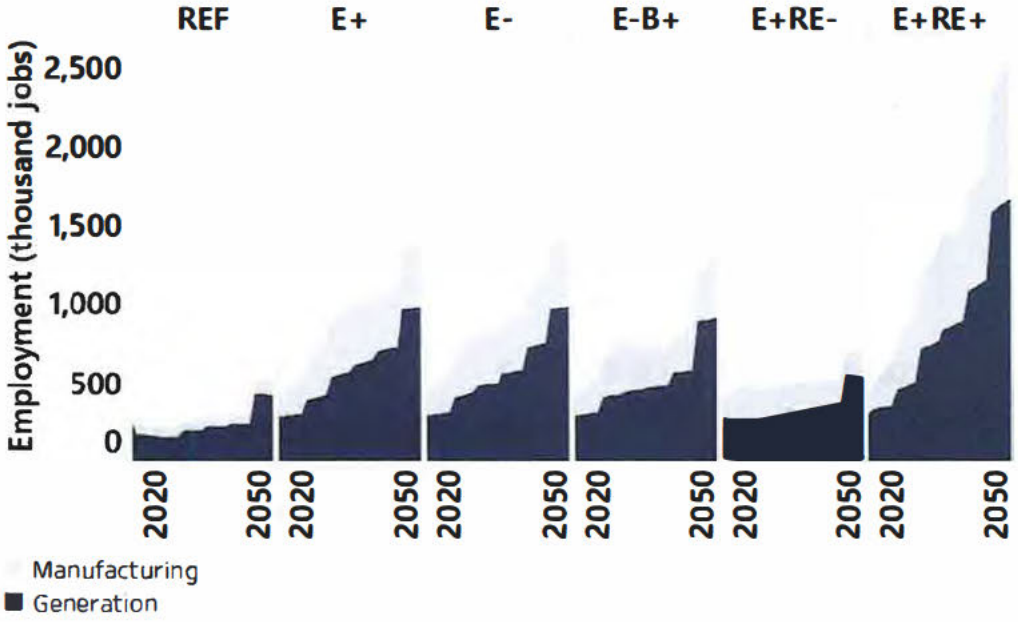
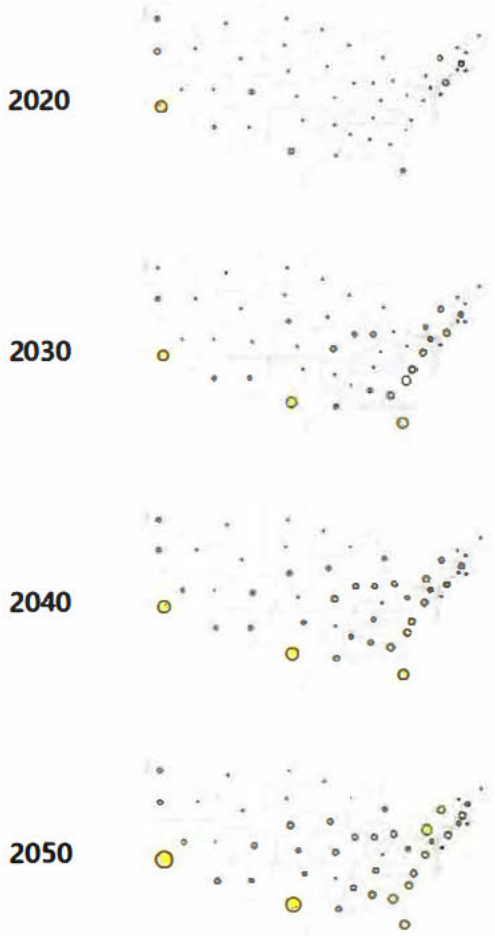
350,000 solar jobs in model year 2020. By 2030, solar is 2nd largest employer, with 80% in generation and 20% in manufacturing.

By 2050, employment in solar sector comprises a third to nearly half of energy-related jobs in net-zero scenarios. Even in reference scenario, solar emerges as the second largest resource sector.



Spatial distribution of employment is influenced by resource quality, siting constraints and decisions, domestic manufacturing.





Note: solar and wind related manufacturing employment estimates assume continuation of current domestic content shares.

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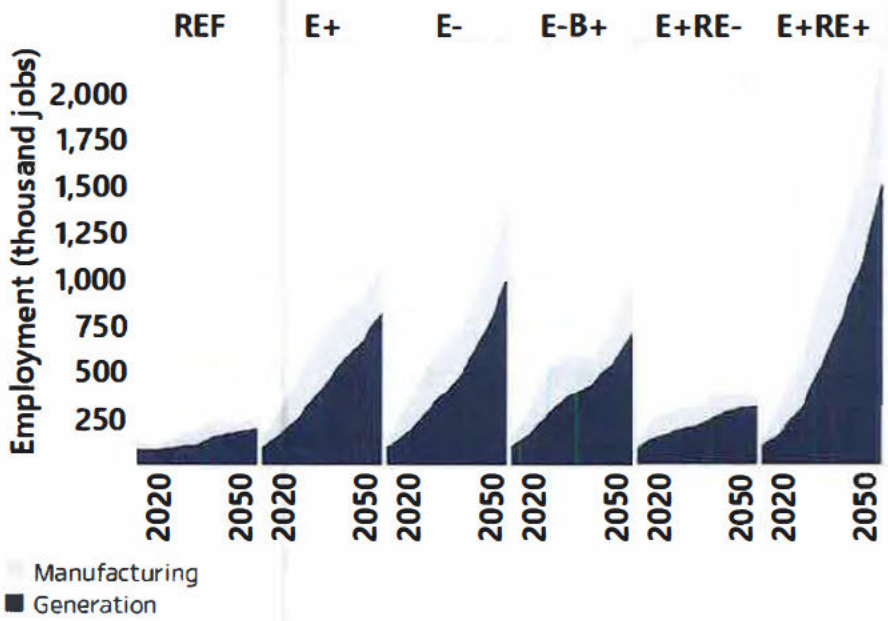
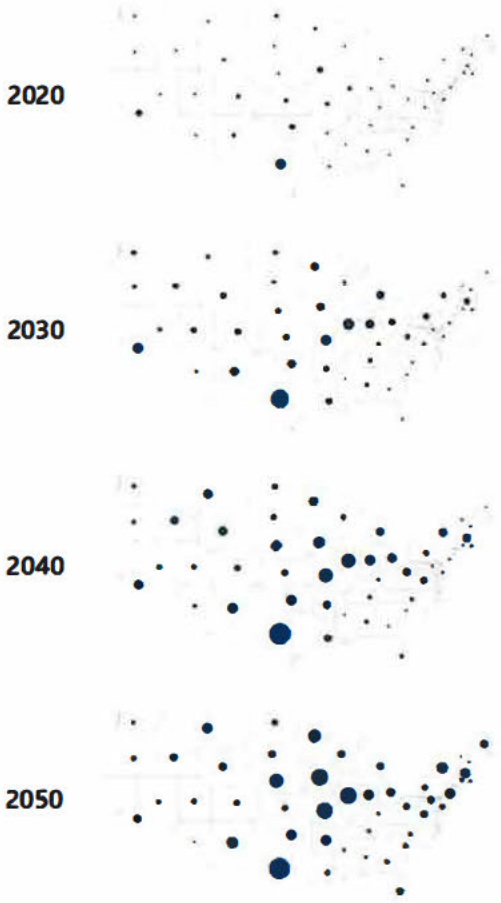
Wind sector employs 120,000, or less than 5% of the energy workforce in 2020.

By 2050, employment in the wind sector comprises 10 to 25% of energy-related jobs in the net-zero scenarios, potentially surpassing the size of the current natural gas sector.



Spatial distribution of employment is influenced by resource quality, siting constraints and decisions, domestic manufacturing.



Note: solar and wind related manufacturing employment estimates assume continuation of current domestic content shares.

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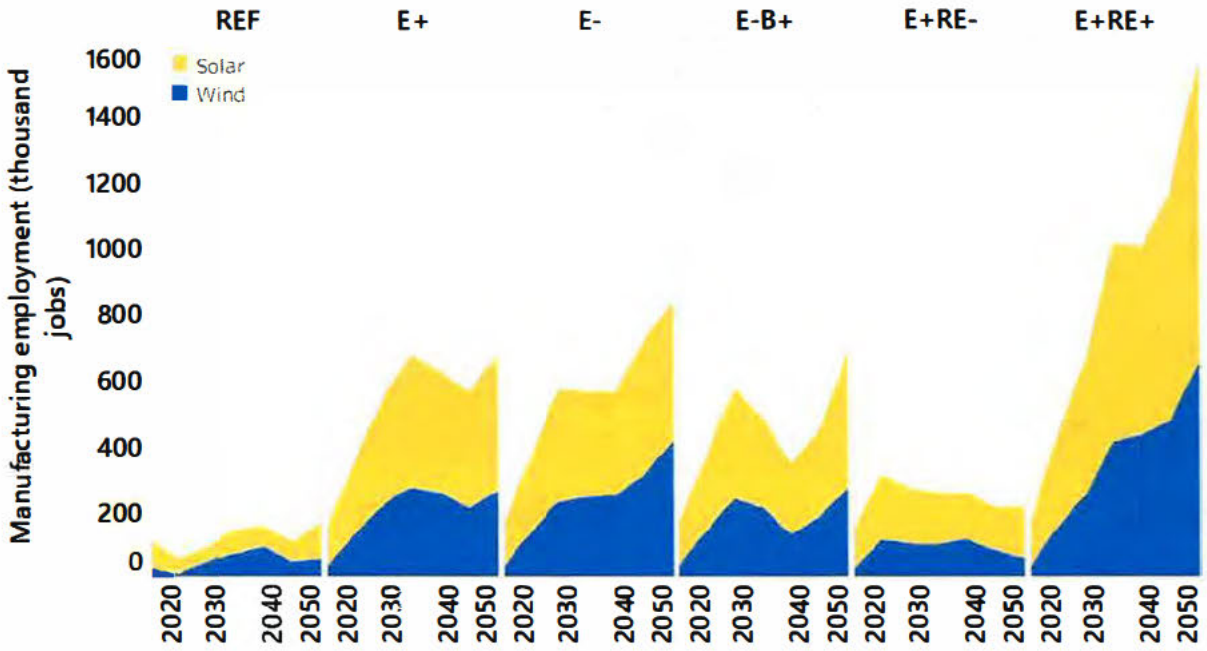
Solar and wind manufacturing offer opportunities to distribute employment benefits across multiple states



Note: Spatial redistribution of solar and wind manufacturing facilities and increasing the domestic manufacturing share offer opportunities to ameliorate losses in fossil fuel extraction states. The estimates here assume 1) manufacturing is sited within the logistic region (see next slide) where solar and wind generation are sited to account for transport between manufacturing and generation, 2) the distribution of manufacturing by state within a logistic region is consistent with the distribution of 2018 energy-related jobs (next slide), and 3) the domestic share of manufacturing is consistent with the historical domestic share (i.e., 77% wind, 11% solar).

There are degrees of freedom in siting solar and wind manufacturing facilities and the amount of manufacturing done domestically. This flexibility can be leveraged to offset job losses in communities, build coalitions, and facilitate legislative bargaining.

- To maintain current domestic shares of manufacturing (77% wind, 11% solar), manufacturing capacity must increase substantially
  - by 2030: 5-10X for wind, 10X for solar
  - by 2050: 5-45X wind, 20-120X solar
- Increasing domestic content share has minimal impact on technology costs, while supporting additional domestic jobs

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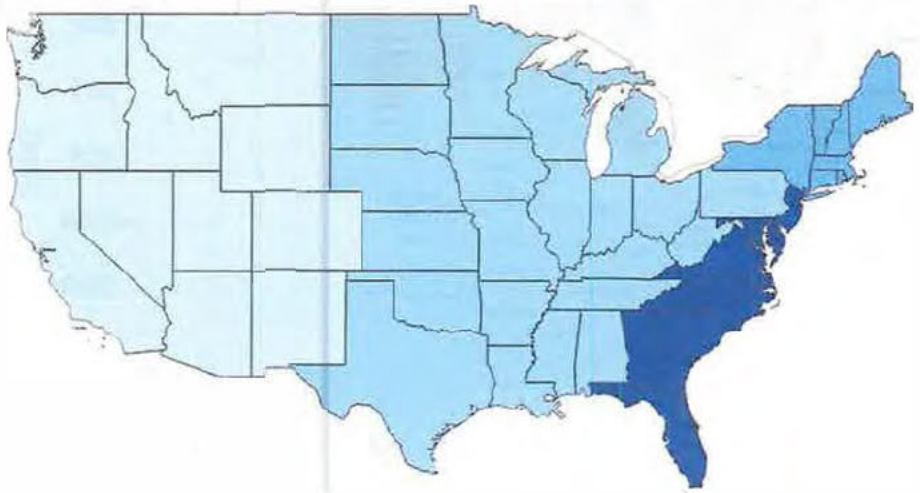
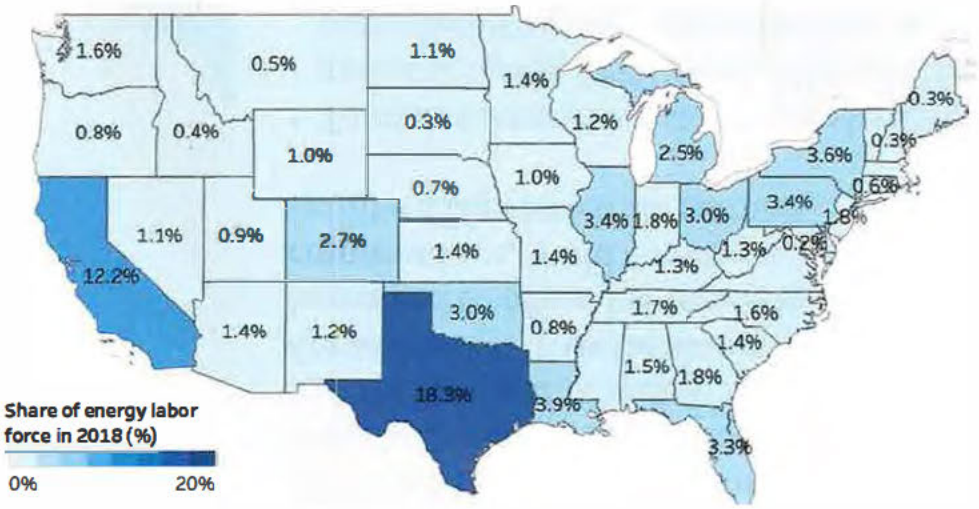
Assumptions for modeling the state-wise distribution of solar and wind manufacturing jobs

The state-wise distribution of solar and wind manufacturing jobs assumes 1) manufacturing is sited within the logistic region where solar and wind generation are sited, 2) the distribution of manufacturing by state within a logistic region is consistent with the distribution of 2018 energy-related jobs, and 3) the domestic share of manufacturing is consistent with the historical domestic share (i.e., 77% wind, 11% solar).

Logistic regions



2018 distribution of energy labor force



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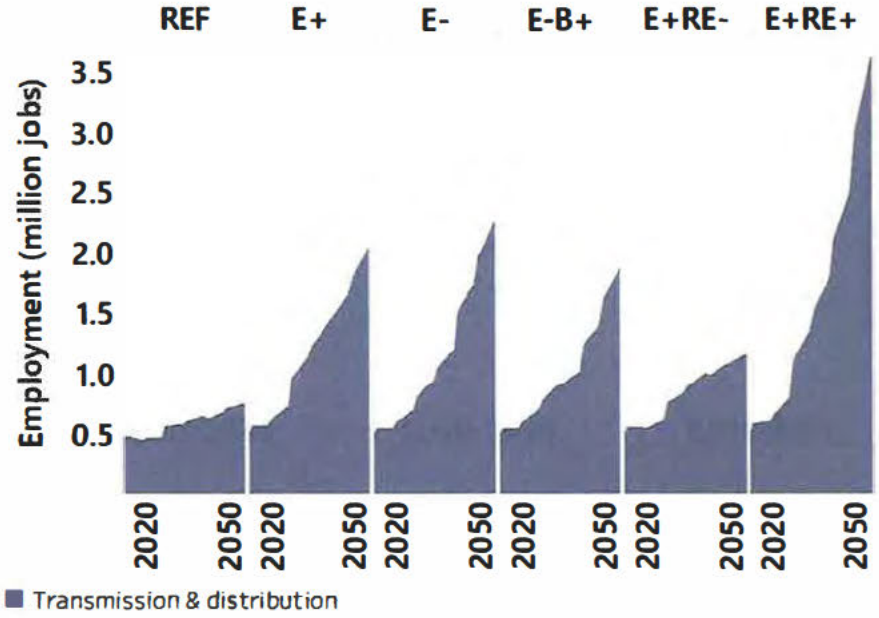
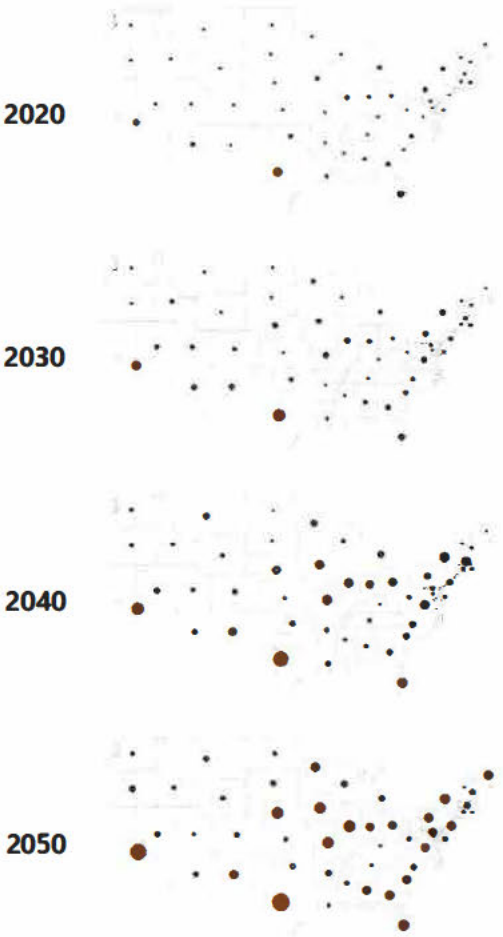
Nearly 460k grid-related jobs today (17% of energy jobs). By 2050, grid-related jobs grow and represent > 1/3 of energy workforce.

Growing employment is largely associated with the 2-4X expansion of grid and ongoing O&M of existing and expanding grid infrastructure. Employment growth is generally correlated with renewables deployment.



Spatial distribution generally correlates with existing grid infrastructure and new renewables.





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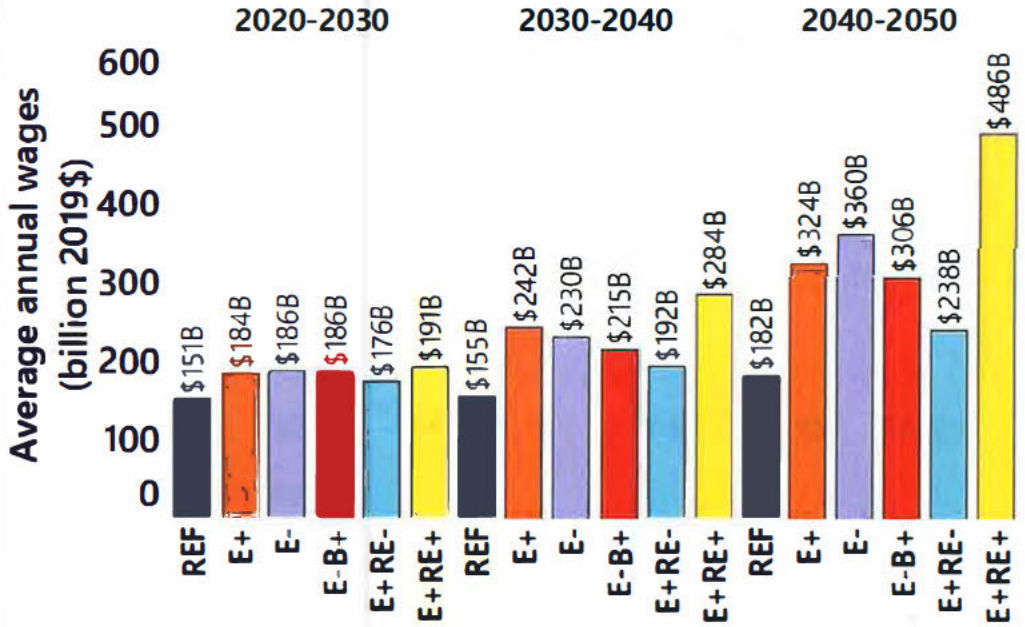
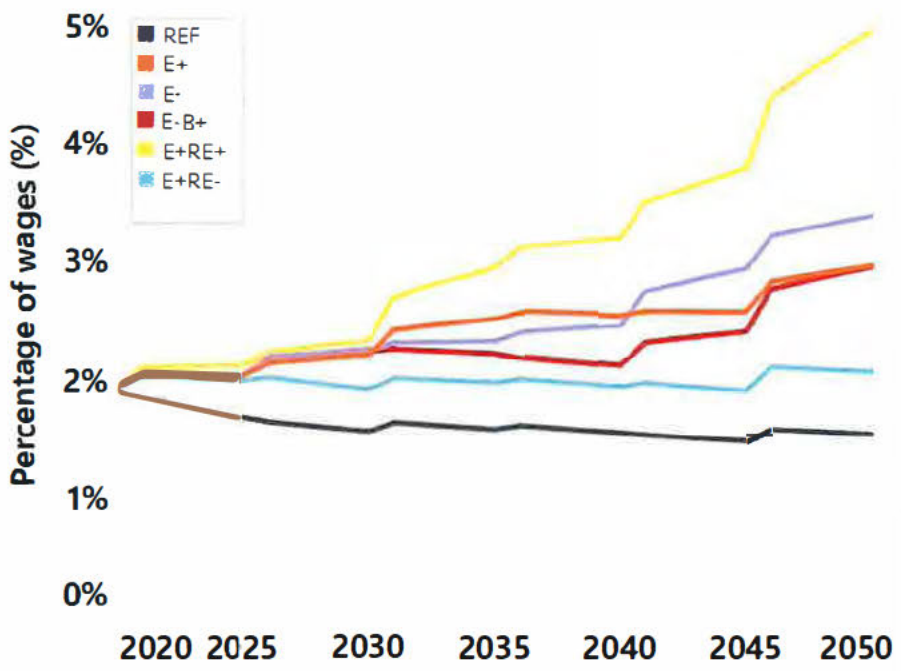
Wages for energy-supply related employment increases through net-zero transitions

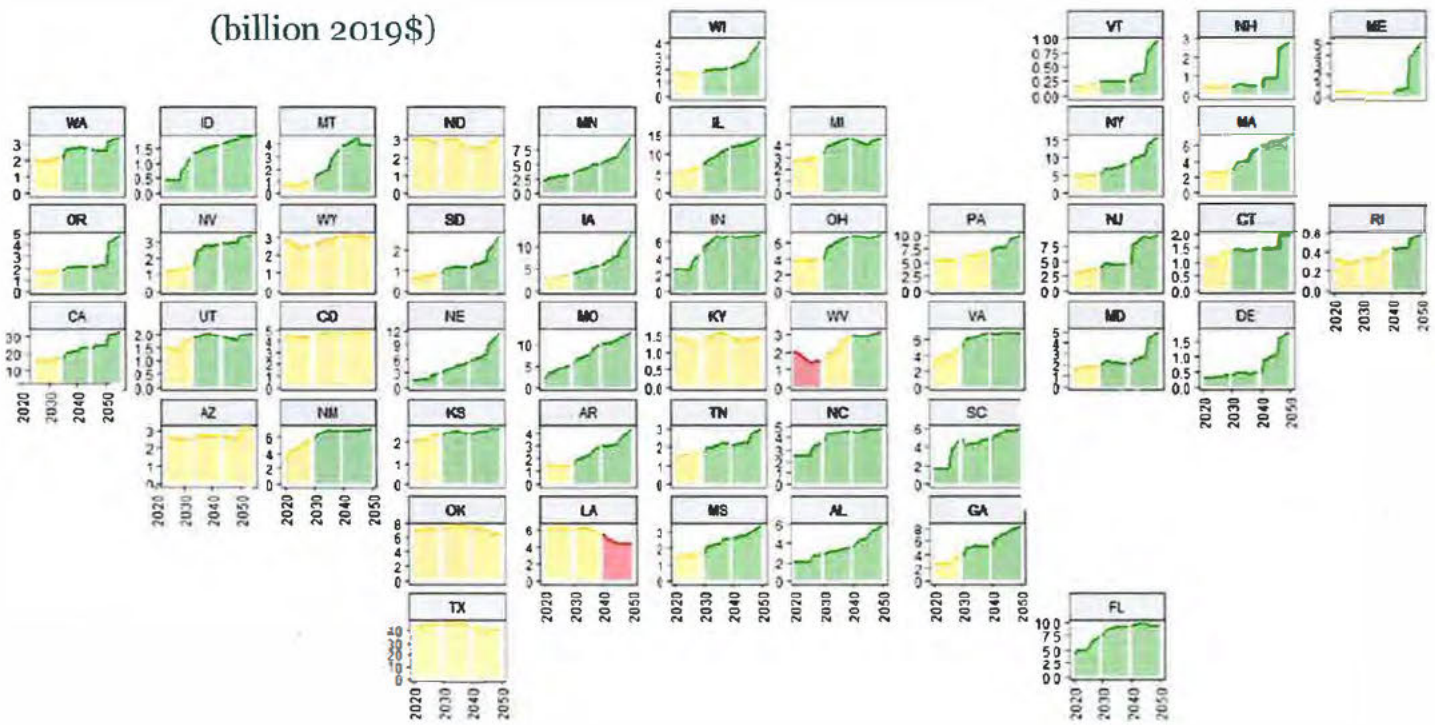
Annual wage income is 180 to 190 B$ in net-zero scenarios in the 2020s, an increase of 30-40 B$ over REF



Energy-related wages represent ~2% of total wages today and 2-5% by mid-century in net-zero scenarios



Modifiable socio-technical factors influence spatial distribution of wages. Below is one instantiation of the future.



Note: Green, yellow, and red coloring indicate whether average annual wages within a decade is more than 15% higher, within 15%, or more than 15% lower than 2021 wages, respectively.

Modifiable sociotechnical factors that influence the spatial distribution of wages:

- Resource quality and availability
- Rate of electrification
- Technology selection
- Domestic manufacturing
- Siting constraints
- Oil and gas exports
- Political and policy processes and constraints

There are several degrees of freedom that can reduce transition risks and be leveraged for political bargaining.

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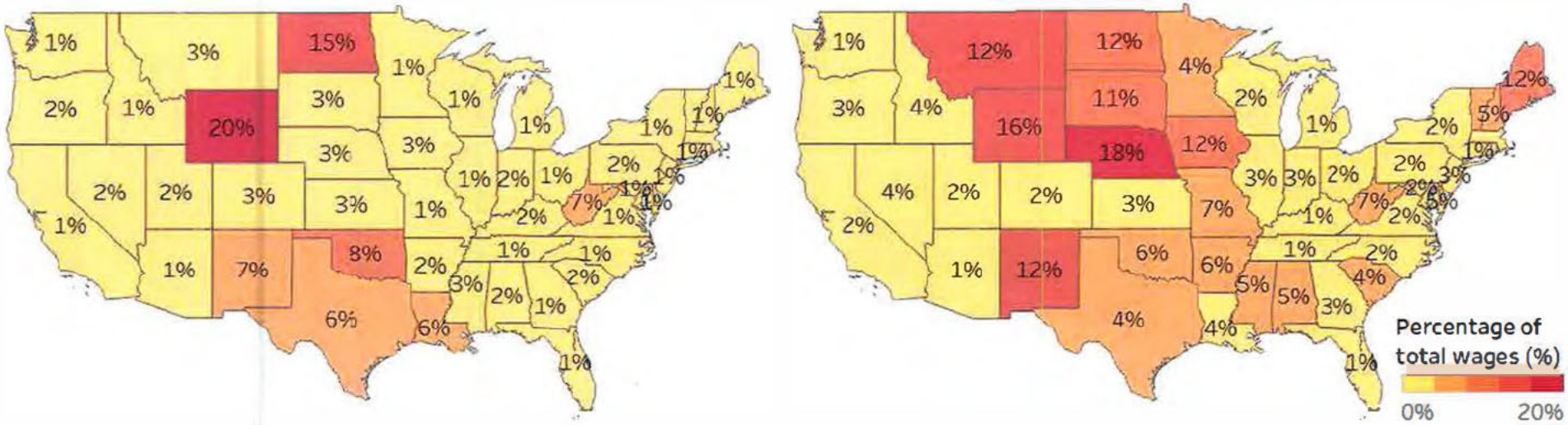
In most states, energy-related wages grow as a share of total wages through the transition period.

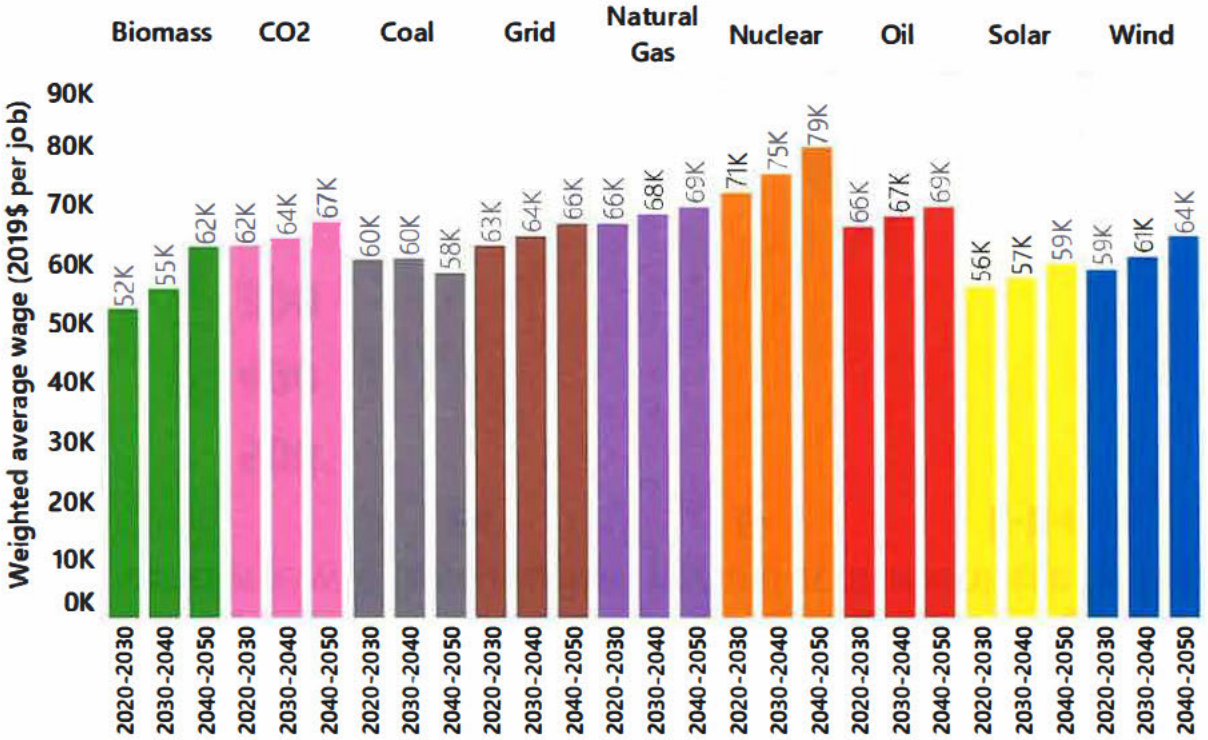
E+ scenario **2020** **2050**



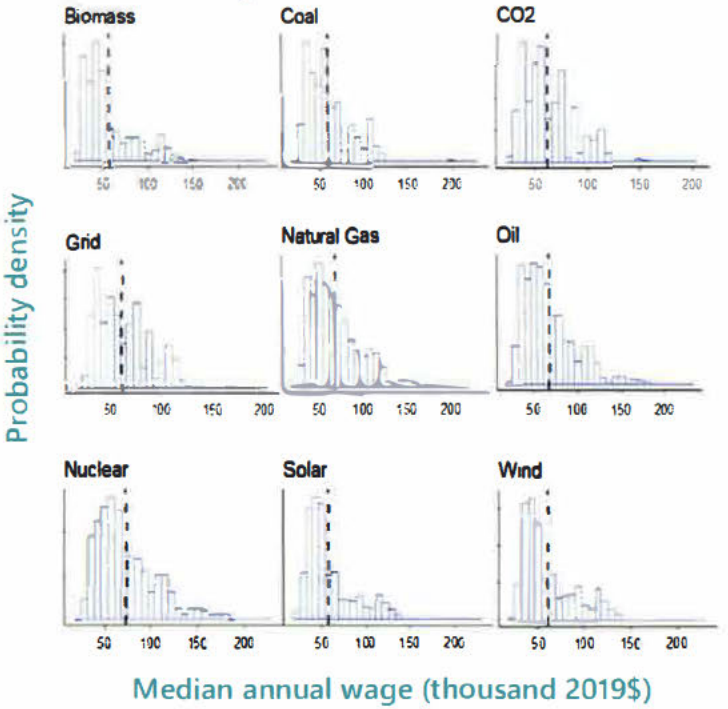
- In a few states with a very high share of the current labor force employed in upstream fossil fuel industries (e.g., WY and ND), energy-related employment wages decrease as a share of the total employment wages.
- In states with high renewable resource quality (e.g., NE, SD, MT, and IA), wages for energy-related employment as a share of total-employment wages grow considerably.

Wages per job for a given resource sector are similar for REF and net-zero scenarios, with some variations between sectors.

E+ scenario



Energy-related jobs are largely middle income jobs, but there is a range across the income spectrum.



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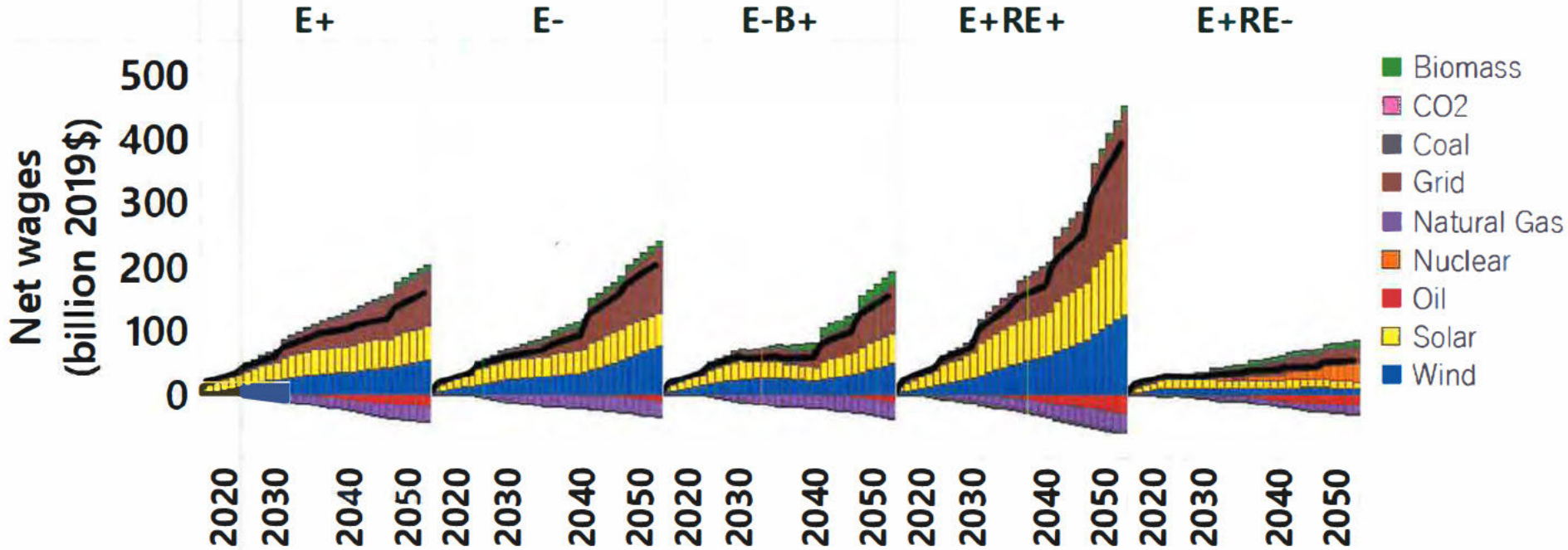
Wages losses in fossil fuel sectors are offset (in aggregate) by added wages in low carbon sectors.

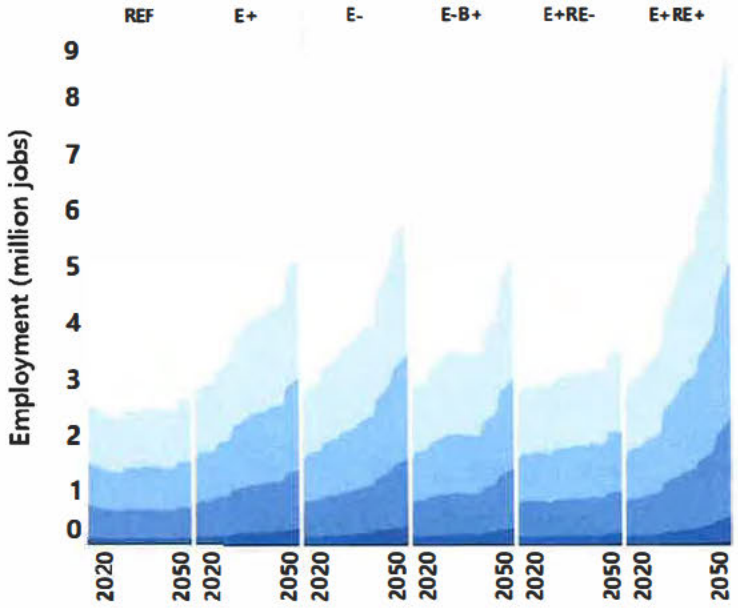
- There is minimal wage loss in fossil fuel sectors in the first decade of the transition.
- By the 2040s, the loss is substantially higher (though much of the current fossil fuel workforce will have reached normal retirement age by that time).



There will be an increasing demand for workers with a diversity of education, experience, and training backgrounds.

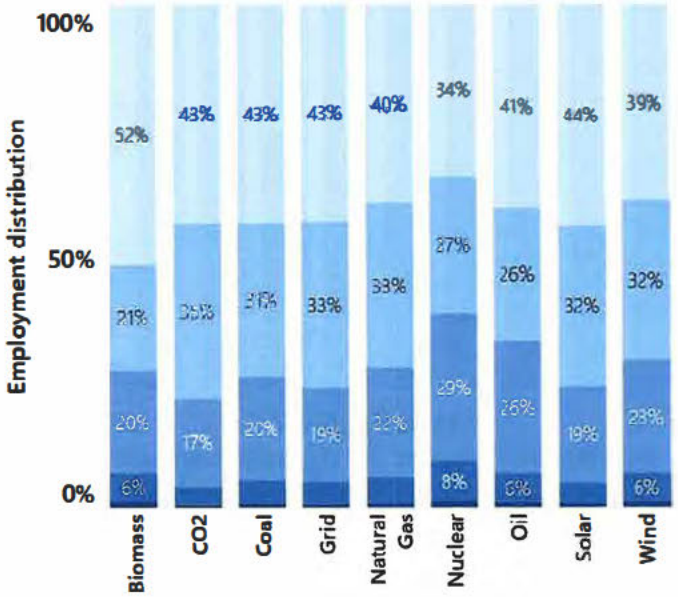


Employment by required level of education



Distribution of employment by required level of education

(results shown for E+ scenario aggregated over 30-yr period)



- High school diploma or less
- Associates degree or some college
- Bachelors degree
- Masters or professional degree
- Doctoral degree

- 30% of the energy workforce will require a bachelor's degree or higher
- Similar distribution of education requirements across reference and net-zero scenarios and over time
- Heterogeneity in education requirements across resource sectors

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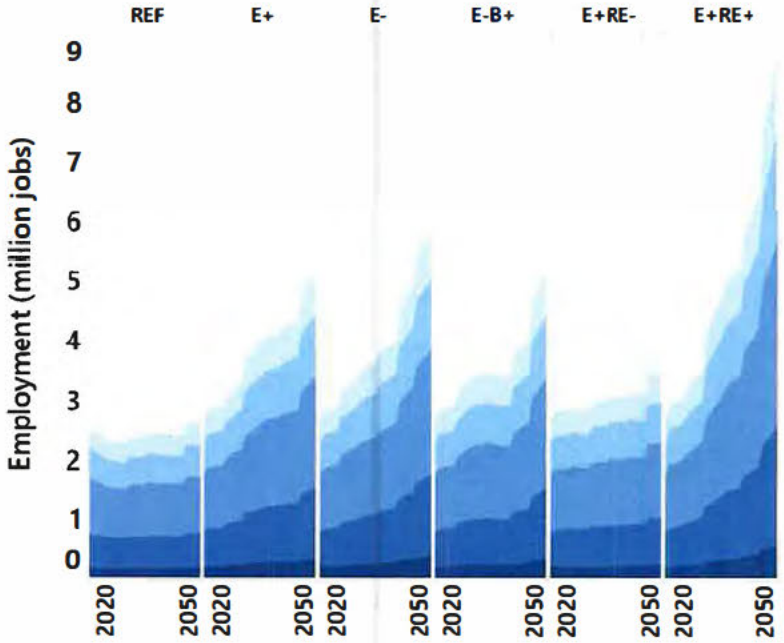
Carbon Mitigation Initiative

There will be an increasing demand for workers with a diversity of education, experience, and training backgrounds.

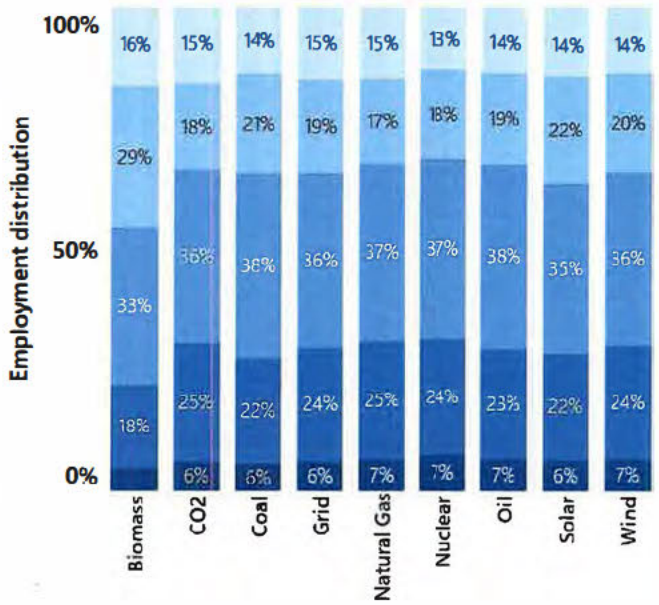


Employment by required years of experience



Distribution of employment by required years of experience

(results shown for E+ scenario aggregated over 30-yr period)



- 70% of the energy workforce requires less than 4 years of related work experience, suggesting minimal lead time required to prepare individual workers.
- Similar distribution of experience requirements across reference and net-zero scenarios and over time.
- Minimal heterogeneity in experience requirements across resource sectors.

Considerations for workforce development programs in net-zero transitions



- The rate of decarbonization is influenced by the organization and availability of labor.
- In established fossil fuel and emerging renewable labor markets, there is evidence of difficulty in hiring, which portends continued employment bottlenecks without countervailing policies and organization.
- Findings suggest that diverse workforce programs (e.g., occupational skills training, college training, and internships) are needed to re-train workers in declining sectors, and train and educate the future workforce.
- Findings suggest that there is minimal lead time required to prepare individual workers.
- Given the magnitude of future labor demand to support a decades-long transition, large-scale and sustained workforce programs and corresponding federal support will be required.
- Entails substantial coordination between unions, public agencies, firms, and workers to meet the evolving needs of both workers and employers to mitigate labor supply bottlenecks.
- Diversity of programs that account for heterogeneity of existing workforces and types of sectors and industries that will be expanded in different regions and communities.
- Beyond training, workforce programs can include recruitment and job placement assistance.

Implications of findings on energy-related employment



- To support a net-zero transition, the supply-side energy workforce may expand by upwards of 30% in the first decade and nearly triple by 2050.
- Net-zero transitions have the potential to significantly transform state and local economies.
- Labor pathways and the distribution of labor are influenced by several modifiable socio-technical factors, such as technology selection, pace of low carbon infrastructure expansion, infrastructure siting and investment decisions, oil and natural gas exports, and domestic manufacturing.
- Modifiable factors can be leveraged to reduce transition risks and to facilitate legislative bargaining.
- Designing policies that anticipate and leverage the skill, temporal, & locational complementarities between workforces of declining and emerging energy sectors can aid in moderating concentrated unemployment and mitigating labor supply bottlenecks.
- Given the magnitude of future labor demand to support a decades-long transition, large-scale, sustained, and diverse workforce programs and corresponding federal support will be required.
- Policy can mitigate the impacts of employment losses for fossil fuel workers and communities.

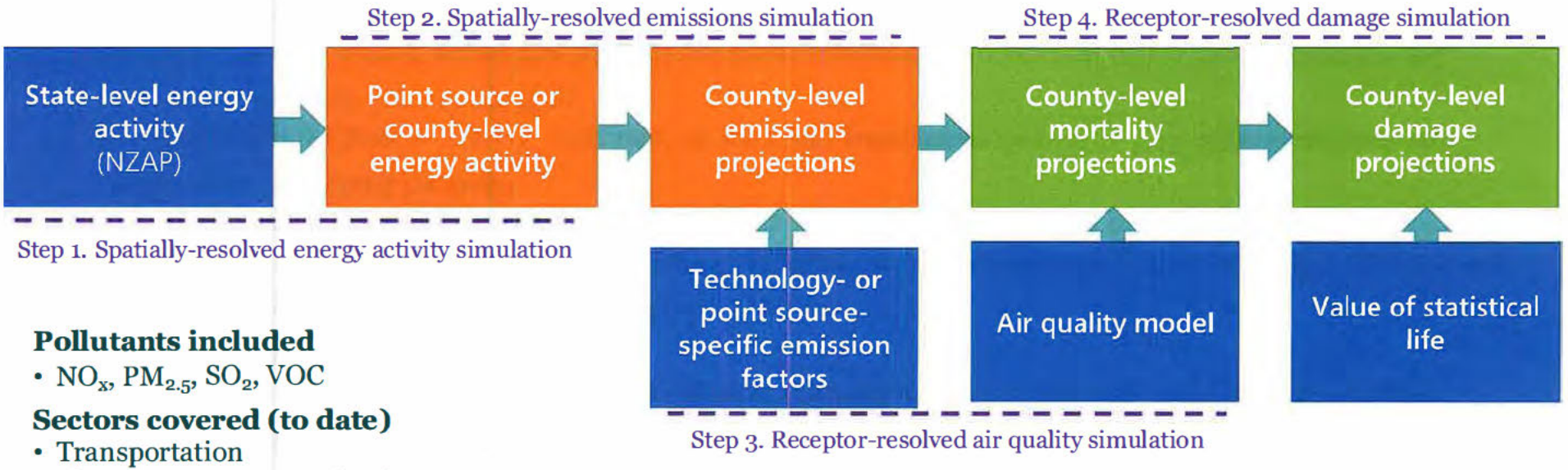
Health impacts related to air quality



Summary of this section

- Historically, there have been persistent and large air quality impacts from fine particulate matter (PM2.5) exposure associated with air pollutant emissions from carbon-producing industries.
- PM2.5 exposure disproportionately impacts lower income populations, although there is variation in the extent of the disproportionate impacts across different industries.
- Siting decisions, technology selection, air pollutant emissions abatement, and rate of electrification influence air quality outcomes.
- With modeling assumptions used in this study
  - About 40,000 premature deaths (~$400B damages) are avoided during the 2020s by transitioning transportation and coal and natural gas electric power sectors to meet an economy-wide target of net-zero emissions by 2050.
  - Cumulatively (2021 – 2050), 200,000 to 300,000 premature deaths (~$2T-$3T damages) are avoided by a net-zero transition.
- Air quality/health impact modeling has not yet been completed for several other important sectors, including industry, biomass production and utilization, oil/gas/coal upstream activities, and other natural gas end uses.

Modeling framework for estimating air pollution and associated health impacts



Pollutants included

- NO_x, $PM_{2.5}$, SO_2, VOC

Sectors covered (to date)

- Transportation
- Electricity generation (coal, gas)

Assumptions:

- Value of statistical life (VSL): 8.9M 2019$ (base), Weibull distribution (from EPA meta-analysis)
- Discount rate: 0% (base) /3%/5%/7%
- Air quality reduced complexity models: AP3 (base), InMAP, APSCA
- Health outcomes assessed: premature mortality
- Dose-response: American Cancer Society (base), Harvard 6 Cities study

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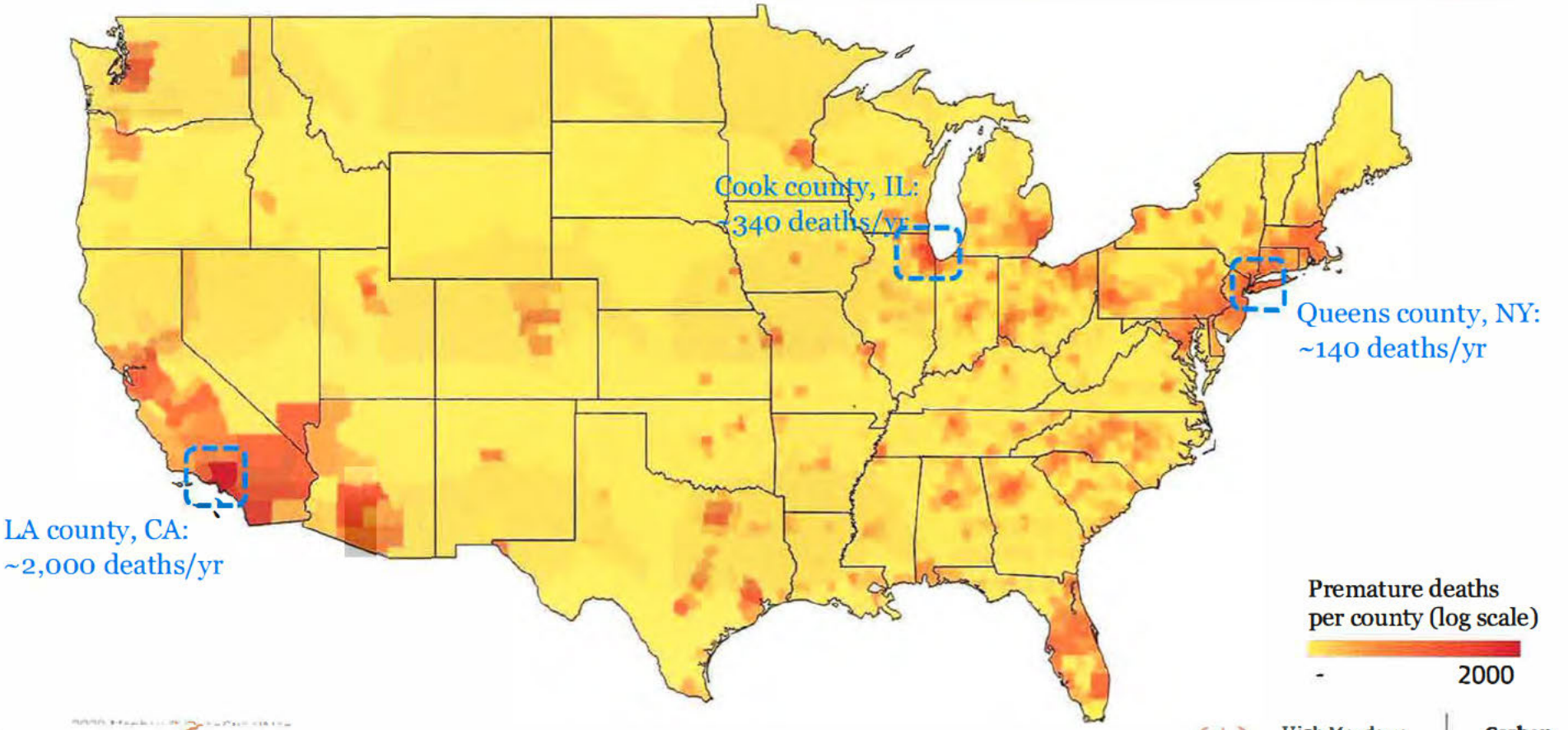
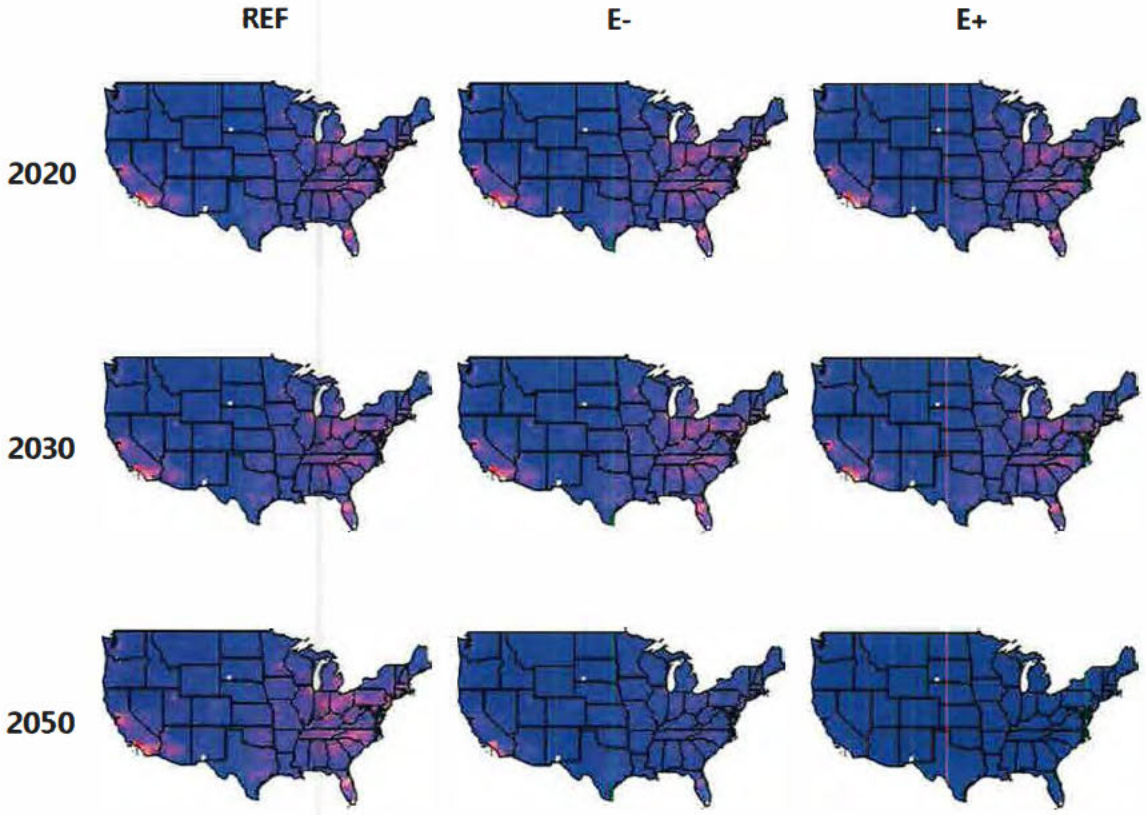
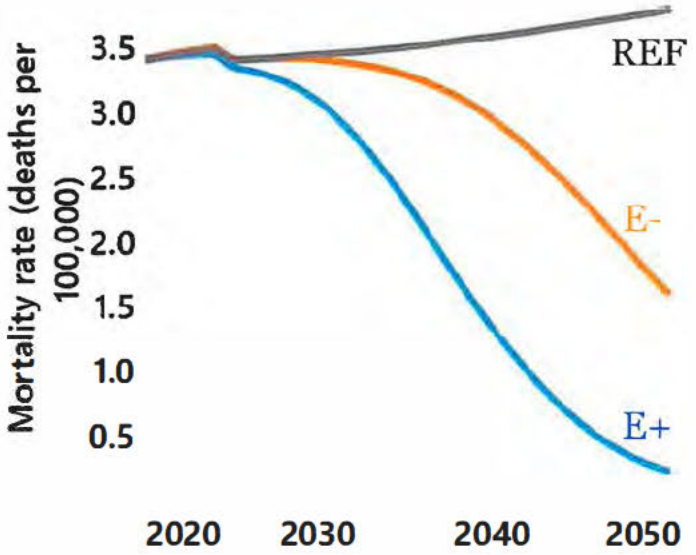
In 2019, ~11,000 premature mortalities ($100B damages) were associated with emissions from the transportation sector.



Mortality associated with transportation emissions are highest in populated areas and are effectively eliminated by 2050 in E+ paths.





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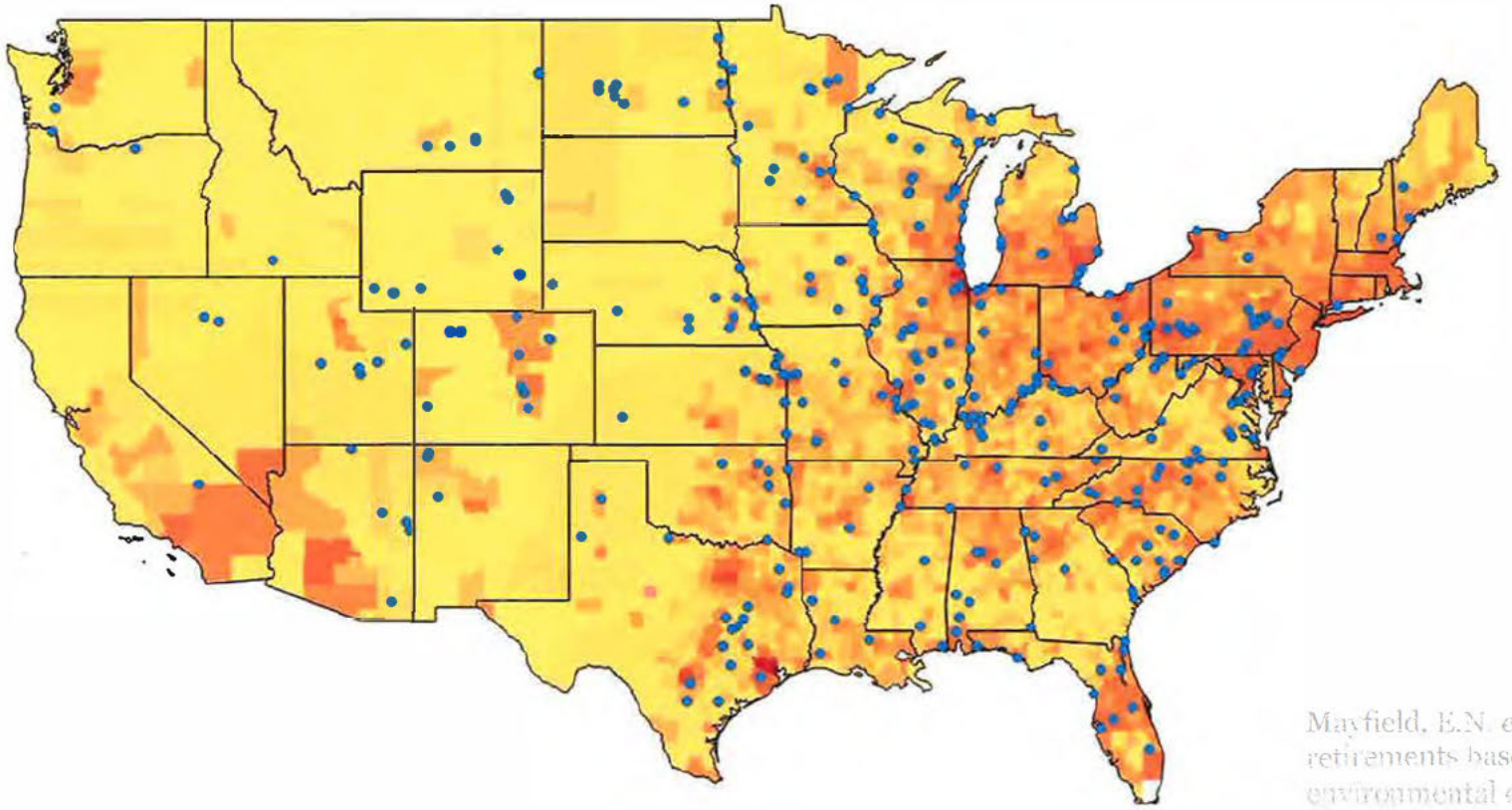
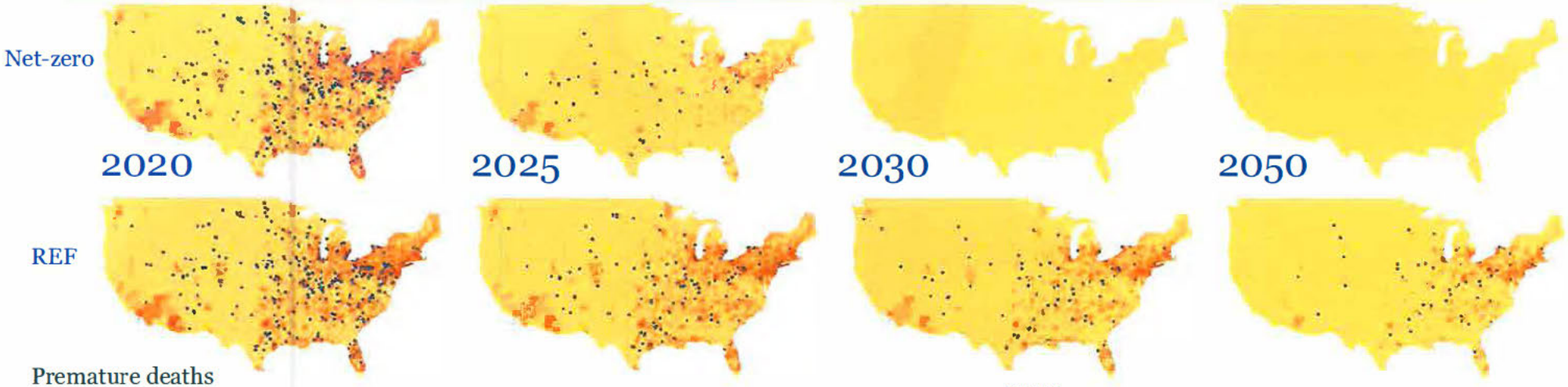
In 2018, 11,000 premature mortalities (~$100B damages) were associated with emissions from 390 coal power plants.



Mayfield, E.N. *et al.* "Sequencing coal retirements based on climate and environmental objectives." *forthcoming.*

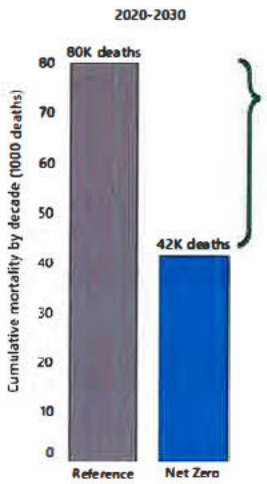
Over 100,000 coal-related air pollution deaths (~1 T$ in damages) are avoided by 2050, with annual mortalities eliminated by 2030.



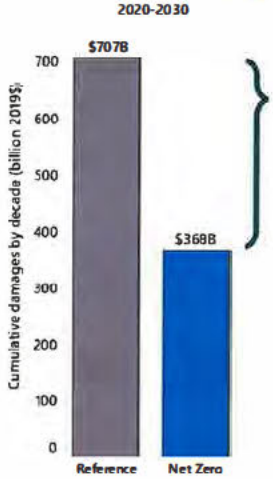
Premature deaths per county (log scale)

\- 300

Coal power plant



~40,000 premature mortalities avoided, 2020 to 2030.



$340B in air pollution benefits, 2020 to 2030

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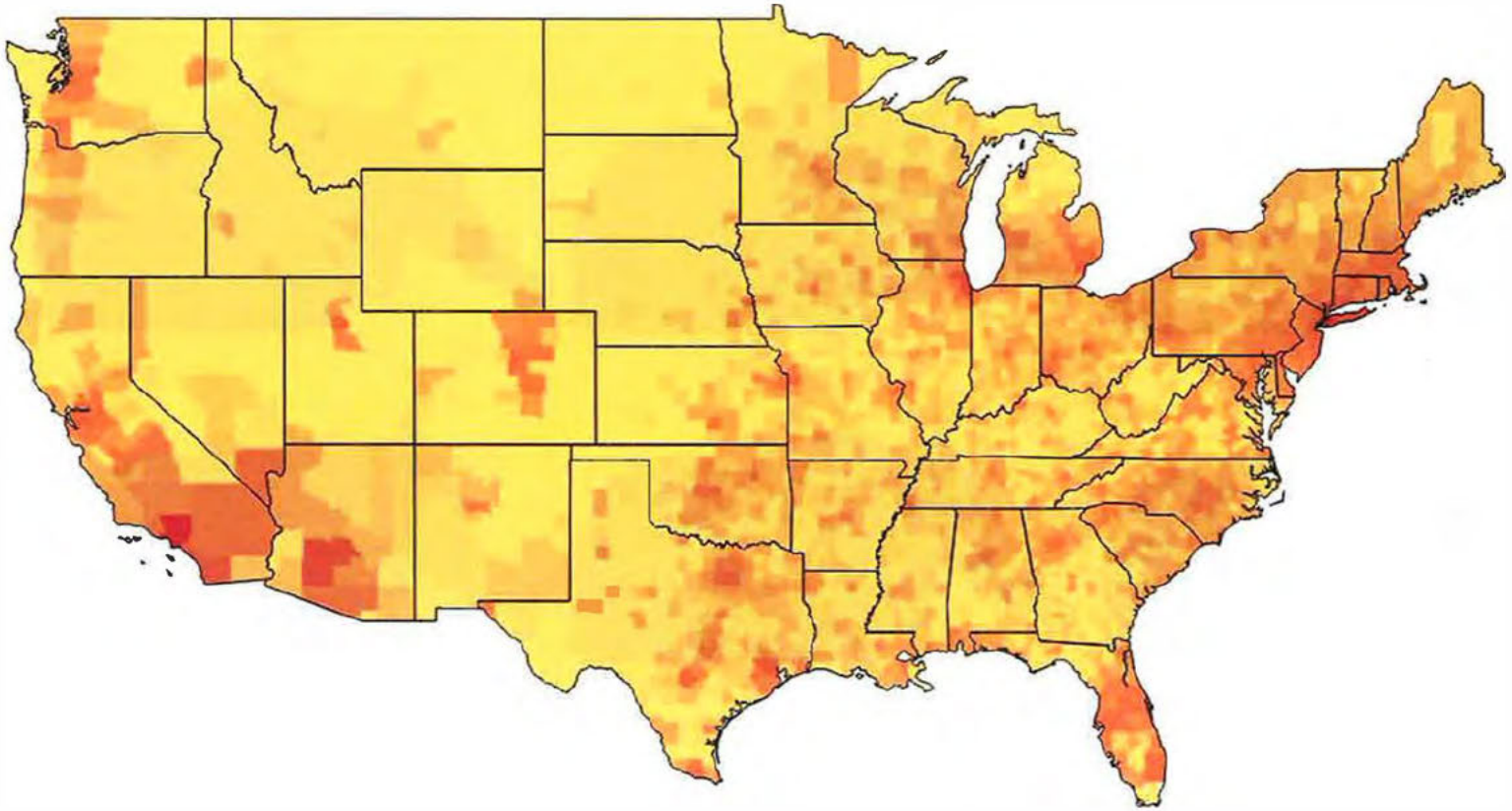
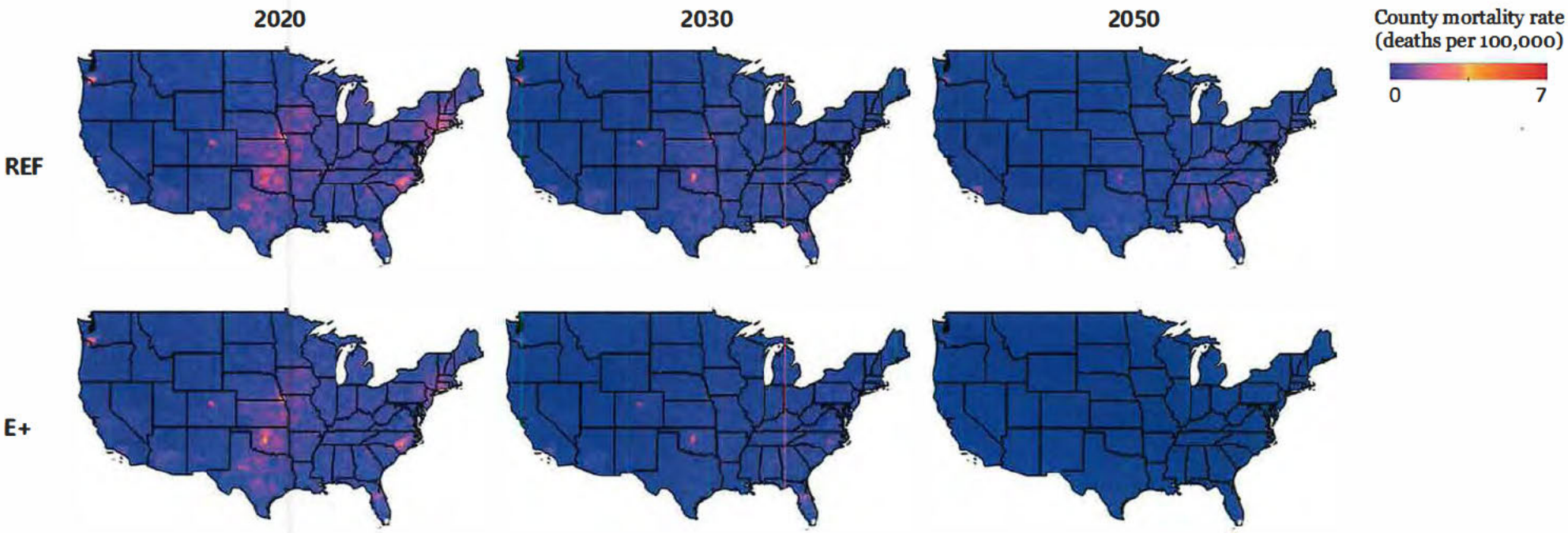
In 2019, ~1,800 premature mortalities ($16B damages) were associated with emissions from natural gas power plants.



Mortality risks from natural gas power generation emissions highest in densely populated counties and those proximate to gas basins



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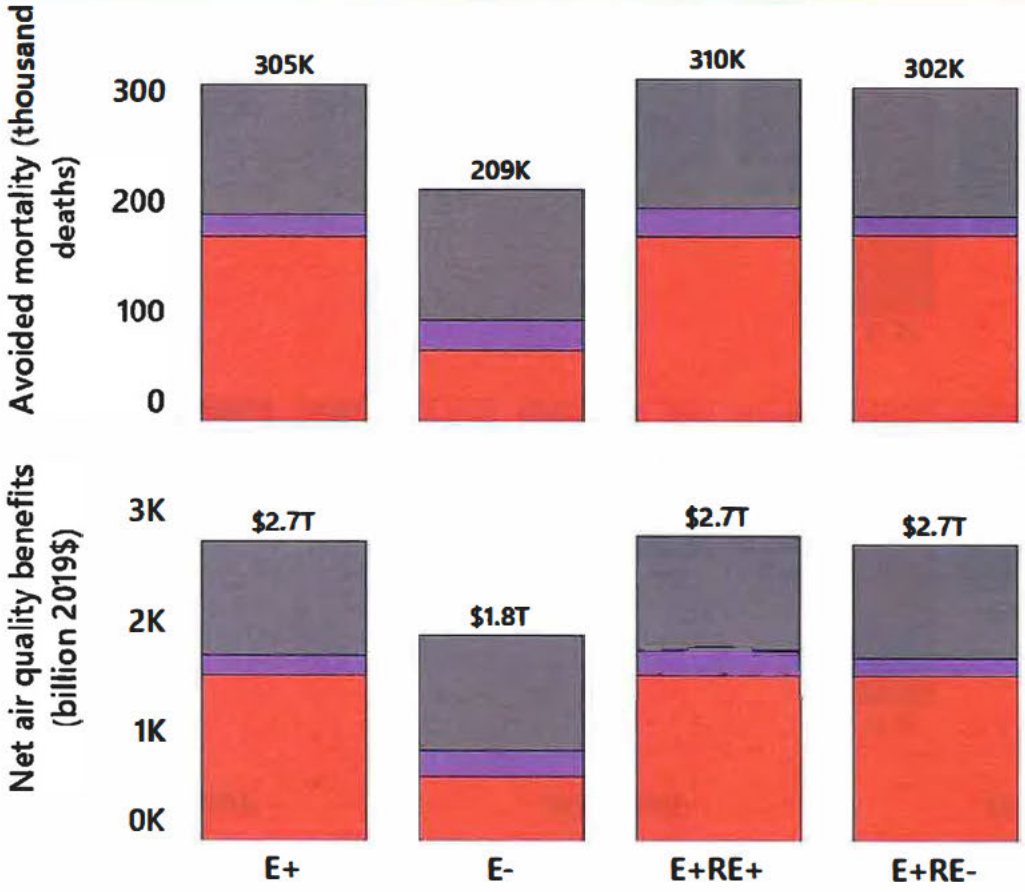
Cumulative air quality benefits, 2020 – 2050, include 200,000 to 300,000 avoided premature deaths (2 - 3 T$ estimated damages)



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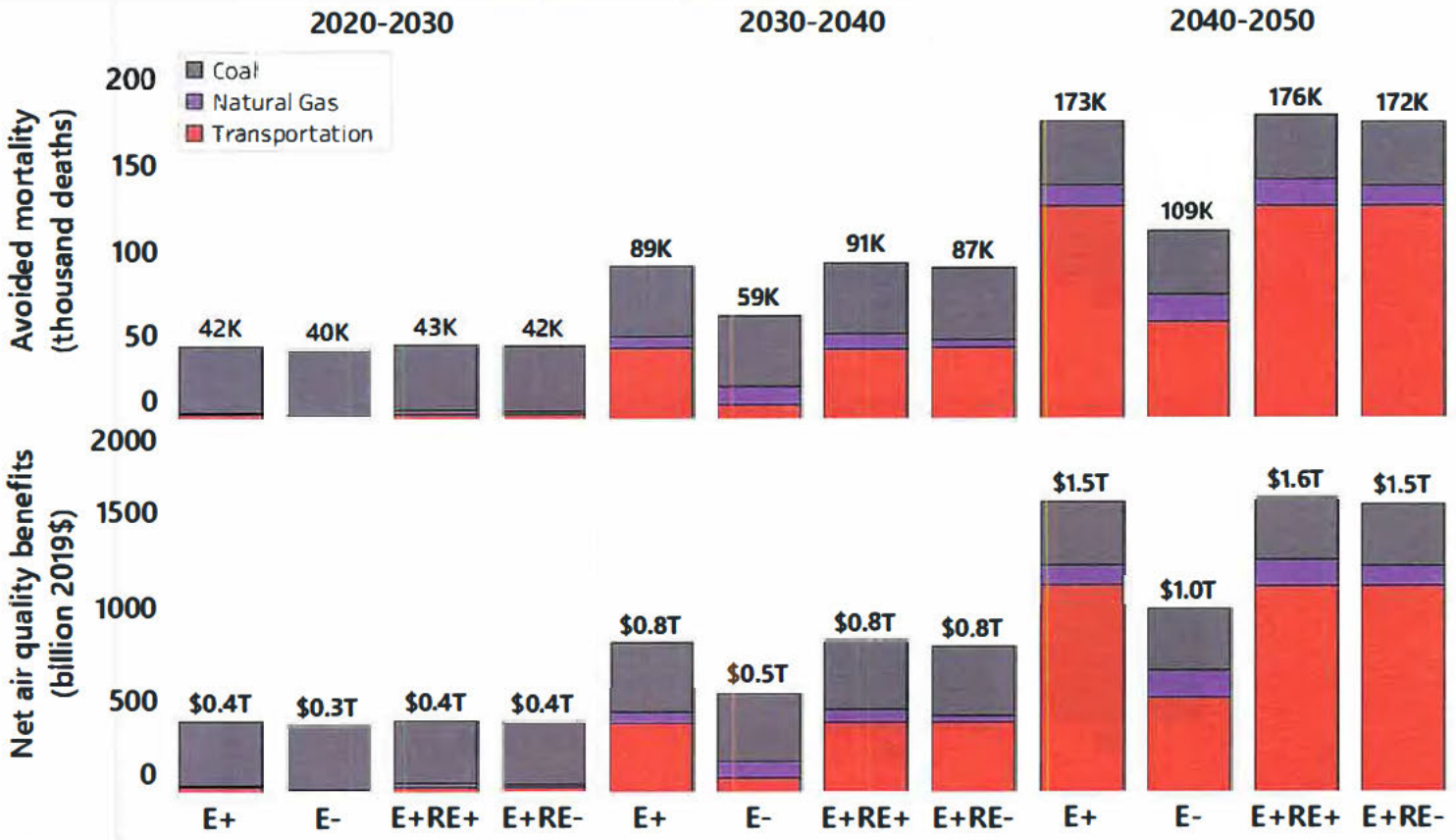
Air quality benefits in 2020s are mostly due to coal plants retiring; benefits from transportation are significant later in the transition



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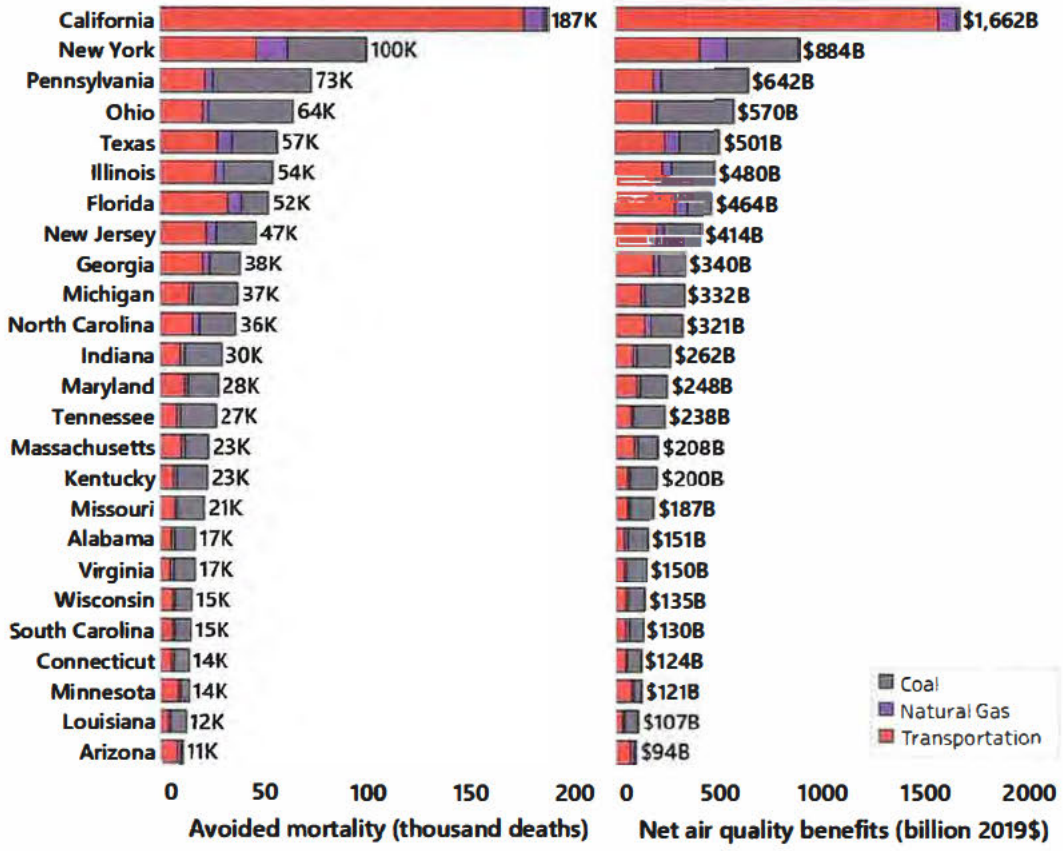
There are large cumulative air pollution-related health benefits across most states.

E+ scenario (relative to REF)



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Temporal and spatial visualization of net-zero pathways point to potential bottlenecks deserving immediate attention and analysis.



Potential bottlenecks for a 2050 Net-Zero America:

- Creation of the coalitions of public support and political will needed to achieve 2020's targets.
- Upfront cost premiums for efficient and electric consumer durable goods (EV's, heat pumps, etc.).
- Rate of mobilization of risk-capital to support project development and construction activities.
- Rate of divestment/new investment among incumbent supply-side and demand-side firms.
- Regulatory capacity to review and permit investment proposals at the required scale and pace.
- Building the EPC and the supply chain capacities needed to support deployment rates.
- Developing human / skills capacity at the pace required to support the transition.
- Concentrated employment losses in particular communities.
- Community opposition to visual and land-use impacts of wind, solar, transmission; bioenergy industrialization; environmental impacts of CO_2 sequestration; nuclear power due to safety and environmental concerns.

A blueprint for action in the 2020s: key priorities



Summary of this section

- This section presents a blueprint for action in the 2020s.
- Priority actions include a set of robust investments needed this decade to get on track to net-zero emissions by 2050, regardless of which net-zero pathway the country follows in the longer term. These can be made with confidence that they will deliver value over the long term:
  - Renewable electricity generation and transmission
  - Electrification of end uses, including vehicles and building heat
  - Industrial productivity improvement
  - Increase carbon uptake and storage in forests and in agricultural soils
  - Reduce non-CO_2 greenhouse gas emissions
- Actions for the 2020s also include a set of important investments in enabling infrastructure and innovative technologies to create real options to complete the transition to net-zero beyond 2030:
  - Plan and begin building:
    - Additional electricity transmission to enable accelerating wind and solar expansion
    - A nationwide CO_2 transportation network and permanent underground storage basins
  - Invest in maturing a range of technologies to make them cheaper, scalable and ready for widespread use in the 2030s and beyond.

Net-zero by 2050 would require aggressive action to start now. Eight Key Priorities for the 2020's



1. Build societal commitment, investment environment, and delivery capabilities
2. Improve end-use energy productivity and efficiency
3. Electrify energy demand, especially transportation and buildings
4. Decarbonize and expand electricity
5. Prepare for major expansion and transformation of the bioenergy industry
6. Build infrastructures: electricity transmission and CO_2 transport/storage
7. Enhance land sinks and reduce non-CO2 emissions
8. Innovate to enlarge the net-zero-carbon technology toolkit

Priorities for the 2020's: Behaviors, institutions, markets



1 Build societal commitment, investment environment, and delivery capabilities

- Major stakeholder engagement campaigns to build:
  - i. *Broad societal awareness* of local, state and national benefits of net-zero energy pathways; and
  - ii. *Acceptance, management, and mitigation of impacts* on landscapes and communities associated with the transition.
- Major consumer awareness campaigns and incentives to drive low-carbon energy investment decisions
- Redesign markets and institutions for a low-carbon future
  - i. *Reform electricity markets* to ensure electricity supply reliability as solar and wind contributions increase; and to value flexibility on both the supply side and the demand side
  - ii. *Improve permitting efficiency* to accelerate successful project and infrastructure siting without compromising quality of environmental and social impact assessment.
  - iii. *De-risk spending of at-risk capital* to accelerate investment decision processes in support of rapid capital expansion
- Develop workforce to support net-zero pathways
  - i. *Signal state-by-state demand and future priorities* to education and training institutions
  - ii. *School outreach programs* to encourage uptake of key STEM degrees, vocational training and trades
  - iii. *Incentive programs* to encourage workforce shifts both between industries and between states
- Major stakeholder engagement campaigns and support programs to mitigate impacts on incumbent sectors and communities and organizations impacted by transitions
- Support for development and rapid expansion of project development capabilities and new industrial capacity and supply chains

Priorities for the 2020's: Demand-Side



2 Improve end-use energy productivity and efficiency

- Industry: Achieve 2% (or greater) per year sustained improvement in industrial energy productivity
- Buildings: Reduce building space conditioning (heating/cooling) energy use through improved building shells, electric heat pumps, and controls
- Appliances: Ensure adoption of most efficient end-use appliances and consumer devices, including conversion of fuel-using devices to electricity
- Vehicles: Increase energy productivity by shifting transportation from single occupancy light duty vehicles to multi-occupancy vehicles, transit, cycling and walking; shift on-road trucking to rail freight; and steadily improve fuel efficiency of new ICE vehicles.

3 Electrify, especially transportation and buildings

- Electric vehicles: By 2030, half of all new light-duty vehicles sold are battery-electric; medium and heavy-duty trucks and bus sales are 15% battery-electric and 10% fuel cell. By 2030, there are ~50 million electric light duty vehicles on the road and ~1M medium and heavy duty trucks and buses. (These targets correspond to E+ scenario. Targets for E- would be lower.)
- Charging infrastructure: Build-out of publically-accessible EV charging infrastructure (ahead of EV adoption rate), including 2.4 million charging ports nationwide by 2030 for E+ scenario or 0.8 million ports by 2030 for E- scenario.
- Space heating: Deploy electric heat pumps in ¼ of current residences by 2030 (25-30 million households) plus ~15% of commercial buildings. Focus on new builds and end-of-life replacement of current stock in climate zones 1 through 5.
- Hot water: Deploy electric heat pump residential water heaters as end-of-life replacements for existing units.
- Automation: Expand automation and controls across electricity distribution networks and end-use devices to unlock flexibility of EV charging, space and water heating loads, and distributed energy resources and minimize distribution network expansion required to support electrification.

Priorities for the 2020's: Supply-side



4 Decarbonize and expand electricity

- Carbon-free electricity: Increase total U.S. electricity generation 10-20% by 2030, and double the carbon-free share (to ~75%).
- Wind and solar: Deploy about 300 GW of wind (3x existing) and 300 GW of solar (~4.5x existing) by 2030, supplying 45-55% of U.S. electricity (vs. ~10% today).
- Coal power: Retire all existing coal-fired power plants, reducing U.S. CO_2 emissions by ~1 billion tons (1/6 of total net U.S. greenhouse gas emissions), while avoiding ~40,000 deaths and ~$400 billion in air pollution damages through 2030. Manage associated operational reliability and local economic transition challenges and impacts. Ready retiring sites for redevelopment as new zero-carbon thermal power plants.
- Nuclear power: Preserve existing nuclear power plants wherever safe, and ready retiring nuclear plants for redevelopment as new zero-carbon thermal power plants.
- Natural gas power plants: Modest decline in generation (10-30%) through 2030 with installed capacity at ±10% of 2020. Existing gas plants play key role providing firm capacity and system flexibility. Avoid new commitments to long-lived natural gas pipeline infrastructure to avoid lock-in.
- Energy storage: 5 to 15 GW of battery energy storage deployed by 2030.

5 Prepare for transformation and expansion of bioenergy industry

- Establish biomass collection/transportation infrastructure: Sustainably use about 80 million t/y of residue biomass for energy by 2030.
- Prepare for dedicated bioenergy feedstock production: Develop high-yield energy crop systems (e.g., switchgrass, miscanthus) for converted (corn) cropland toward commencement of commercial harvests in 2035 and ramping up to 80 million tonnes/year of production by 2040 across 4 million hectares.
- Prepare bioconversion industry transition: Demonstrate advanced gasification-based bioconversion technologies for fuels production and design commercial-scale facilities to be deployed in the 2030's.

Priorities for the 2020's: Network Infrastructures



6 a. Expand critical electric network infrastructure

- Electric transmission: Build ~195,000 GW-km of new transmission lines connecting solar / wind projects to loads by 2030 (~60% increase over current US transmission capacity). Strengthen and expand U.S. long-distance electricity transmission by identifying corridors needed to support wind and solar deployment (through 2030 and beyond given long lead time for transmission), reform siting/cost allocation process, and develop stakeholder consensus/support to site transmission connecting high renewable development potential zones.
- Electric distribution: Strengthen distribution system planning, investment, and operations to allow for greater use of flexible demand and distributed energy resources, improve distribution network asset utilization, and efficiently accommodate 5-10% increase in peak electricity demand from EVs, heat pumps, and other new loads by 2030. Prepare for more rapid electrification and peak demand growth after 2030.

6 b. Expand critical CO_2 capture and storage infrastructure

- Interstate CO_2 trunk line network: Plan, site, and construct an "interstate CO_2 highway system" (trunk line network) by 2030 (~19,000 km), connecting all regions to CO_2 storage basins in Gulf Coast, West Texas (Permian), Midwest (IL, IN, MO, KY), Dakotas/Eastern MT (Bakken), and California Central Valley.
- CO_2 storage regulations: Finalize national and/or state regulatory conditions governing: pore space ownership and access; well standards; injection operations; measurement, monitoring and verification of CO_2 containment (during- and post-injection); and long-term liability.
- CO_2 reservoir exploration and appraisal: Characterize with high confidence all major basins for CO_2 sequestration and identify sites suitable for injection of approximately 250 million metric tons of CO_2 per year by 2030. Advance field development planning and permitting.
- Carbon capture and sequestration: Capture and sequester 65 million metric tons of CO_2/year by 2030, including CO_2 capture at 5 world-scale cement plants, 5-10 natural gas power plants, and 5-10 large-scale steam- or autothermal-reforming plants making hydrogen.

Priorities for the 2020's: Land Sinks and Non-CO_2 Emissions



7 a. Protect and enhance land carbon sinks

- Grow the land sink: Deploy measures to achieve 200 million tCO_{2e} per year of additional sequestration in 2030 compared with 2020 so as to offset business-as-usual reduction of natural land sinks and achieve a net increase in the land sink of 50 million tCO_{2e} per year.
  - i. *Forestry sector*: Target 160 million tCO_{2e} per year additional sequestration through deployment of a variety of measures.
  - ii. *Agriculture*: Target 40 million tCO_{2e} per year additional sequestration, primarily through measures employed on croplands.
- Prepare for future land-sink growth: Establish institutional mechanisms to ensure additional land sink enhancements beyond the 2020's.

7 b. Reduce non-CO_2 emissions

- Non-CO_2 GHGs: Reduce non-CO_2 greenhouse gases by at least 10% by 2030, including
  - i. *Reducing HFC production and consumption* consistent with the Kigali Amendment to the Montreal Protocol.
  - ii. *Identifying and eliminating largest CH_4 leakage sources in oil and gas* production, processing, and pipelines.
  - iii. *Improving management of N_2O and CH_4 in agriculture.*
  - iv. *Managing N_2O emissions from nitric and adipic acid production.*

Priorities for the 2020's: Innovation



8 Innovate to create additional *real* options for technologies needed post-2030

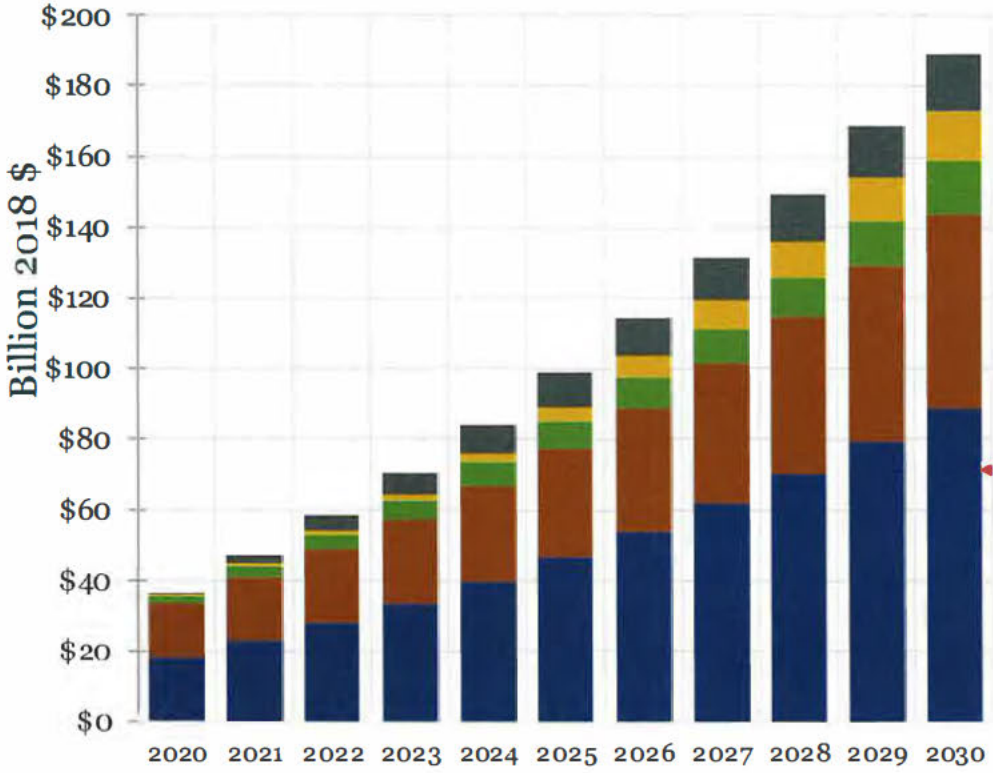
- Technology option creation: Pursue maturation, scale-up, and cost/performance improvements in clean-energy technologies, including:
  - *Clean firm electricity resources*, including advanced nuclear, advanced geothermal, natural gas power plants with CO_2 capture, biopower plants with CO_2 capture, hydrogen and ammonia combustion turbines; ultra-cheap long duration energy storage;
  - *Hydrogen production* via electrolysis, natural gas reforming with CO_2 capture, and biomass gasification with CO_2 capture;
  - *Synthesis of fuels from biomass and H_2 + CO_2*, including methane and liquid hydrocarbons (e.g., Fischer-Tropsch fuels);
  - *Direct hydrogen-reduced iron* and other carbon-free alternatives for primary steel production;
  - *CO_2 capture* in a range of industrial applications, including cement, ammonia, biofuels, and hydrogen;
  - *High-yield bioenergy crops* such as miscanthus
  - *Direct air capture* methods

  $130 Billion: Order-of magnitude capital cost estimates for up to 5 first-of-a-kind (FOAK) demonstrations for each technology above, including FOAK premiums.
- Technology innovation to reduce siting challenges: Increase investment in research and technology solutions that reduce network infrastructure siting challenges, including repurposing existing natural gas or oil pipelines for hydrogen or CO_2 transport, low-cost underground transmission lines and increasing utilization/transfer capacities of existing electricity transmission.

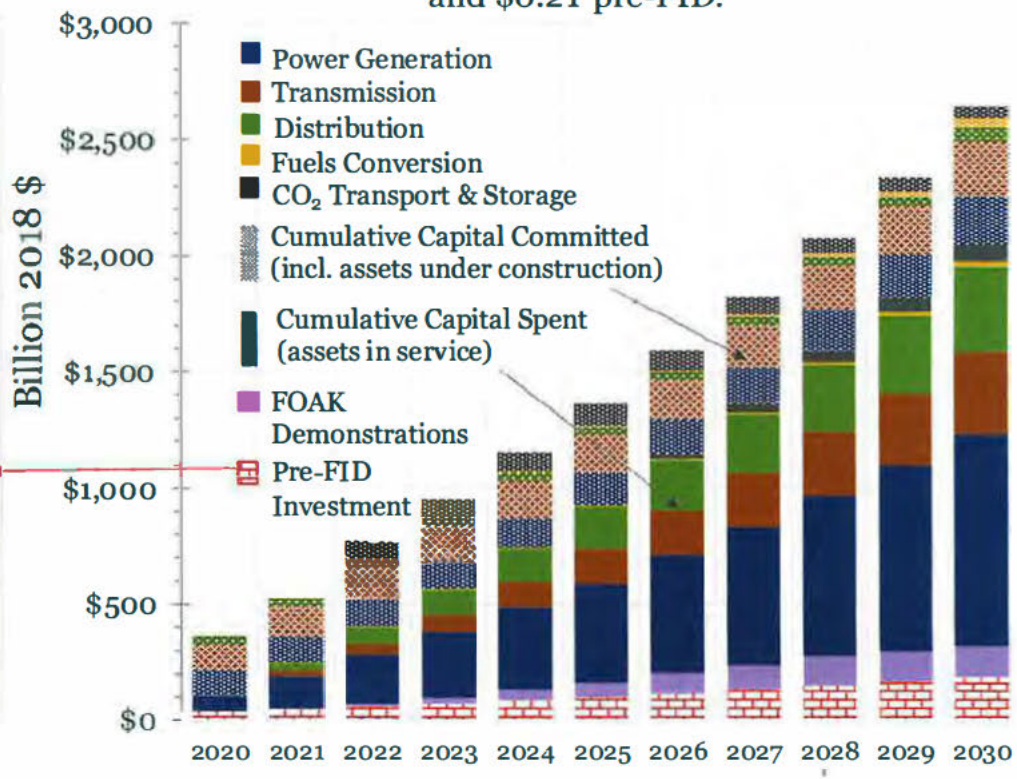
All net-zero scenarios are capital intensive. Mobilizing risk capital for development and construction will be a significant challenge

E+

$190 B$ at-risk pre-FID development costs in 2020's to support **supply-side** capital investment decisions



2.6T$ committed to **supply-side** plant & infrastructure in 2020's: $1.8T in service, $0.6T in construction, and $0.2T pre-FID.



Note: Excludes investments in demand-side transport, buildings and industry; biomass crop establishment; and land sink enhancements.

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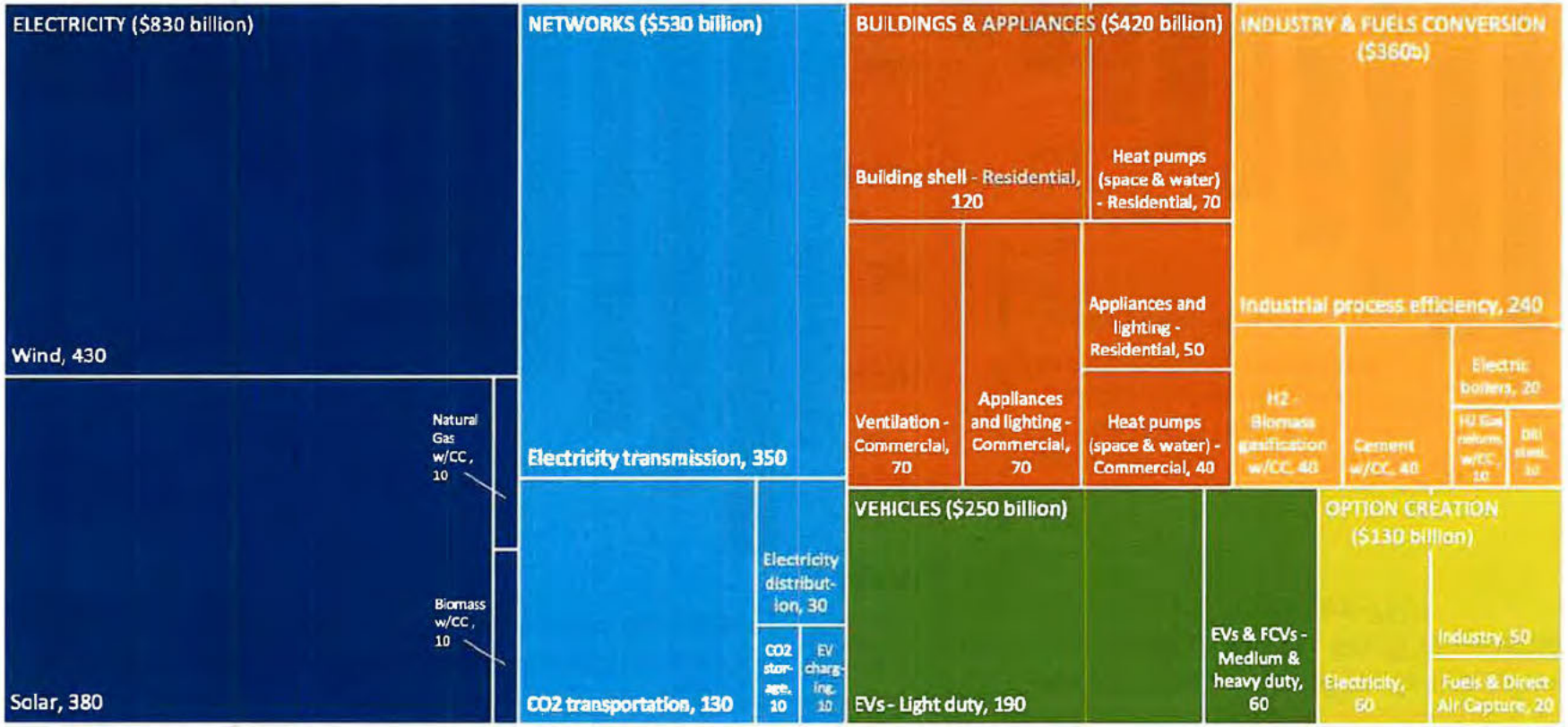
Net-zero path requires **$2.5 T additional capital** in 2020s (vs. REF) across energy supply, buildings, appliances, vehicles, industry.

Total additional capital invested and committed, 2021-2030, by sector and subsector for E+ vs. REF (billion 2018 $)



Includes capital invested pre-financial investment decision (pre-FID) and capital committed to projects under construction in 2030 but in-service in later years.
All values rounded to nearest $10b and should be considered order of magnitude estimates. Incremental capital investment categories totaling less than $5B excluded from graphic.

Other potentially significant capital expenditures *not* estimated in this study include establishment of bioenergy crops and decarbonization measures in other industries besides steel and cement, non-CO_2 GHG mitigation efforts, and establishing enhanced land sinks.

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Technical annexes provide details on methods, assumptions, and data sources for national scenarios and downscaled results.



A. Evolved Energy Research final report
B. Transition pathway sensitivity studies
C. Transport & buildings transitions
D. Solar and wind generation transition
E. Thermal power plants transition
F. Electricity transmission transition
G. Electricity distribution system transition
H. Bioenergy supply industry transition
I. CO_2 transport and storage transition
J. Iron and steel industry transition
K. Cement industry transition
L. Hydrogen transition
M. Mobilizing capital for the transition
N. Fossil fuels transition
O. Non-CO_2 emissions transition
P. Forest land sinks analysis
Q. Agricultural land sinks analysis
R. Employment transition
S. Air quality / health impacts transition

Technical annexes are available for download at https://bit.ly/NetZeroAmerica